The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries

Geoff B. Barker IEng. MEI.

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ELSEVIER

Gulf Professional Publishing
An imprint of Elsevier

Gulf Professional Publishing is an imprint of Elsevier
50 Hampshire Street, 5th Floor, Cambridge, MA 02139, United States
The Boulevard, Langford Lane, Kidlington, Oxford, OX5 1GB, United Kingdom

Library of Congress Cataloging-in-Publication Data
A catalog record for this book is available from the Library of Congress

British Library Cataloguing-in-Publication Data
A catalogue record for this book is available from the British Library

ISBN: 978-0-12-814653-8

Publishing Director: Joe Hayton
Senior Acquisition Editor: Katie Hammon
Editorial Project Manager: Andrae Akeh
Production Project Manager: Paul Prasad Chandramohan
Cover Designer: Matthew Limbert

Typeset by SPi Global, India

To my wife and two sons, who without their encouragement and understanding this book would never have been completed.

Contents

About the Author

Geoff Barker is a retired professional engineer and principal consultant at Independent Oil and Gas Consultants. He is registered as an incorporated engineer with the Engineering Council in the UK, where he studied for his Higher National Certificate in Mechanical Engineering and also received his initial engineering training.

The author is a member of the Energy Institute (UK) and a former member of the Institution of Plant Engineers (UK), the Society of Operations Engineers (UK), and the Institute of Engineering Technology—UK).

He has more than 40 years of industrial and consultancy experience worldwide in onshore and offshore oil and gas industries, as well as in petrochemical, mining, pharmaceutical, and food processing industries.

After his early training in the UK, the early 1970s saw the author undertake engineering positions in Toronto, Canada, where he studied for and received accreditation in process plant piping design and calculation. The latter part of the 1970s took the author to Alberta to work on oil and gas projects in that province, where he studied natural gas processing and gas plant operations at The Southern Alberta Institute of Technology.

The author has held engineering design and field engineering supervisory positions while working in Canada.

The 1980s saw the author move to Europe to work on onshore and offshore projects in the UK, Norway, and in the Netherlands.

Geoff has held both onshore and offshore engineering design and field engineering supervisory positions while working in Europe and Scandinavia.

In 1989, the author moved to Houston, Texas, where he worked on many oil and gas projects; these projects not only took him to the many corners of the USA but also to South America, China, and India.

The author has held engineering and management positions at most of the large oil and gas EPC companies in Houston.

He is a member of the American Society of Mechanical Engineers and has received accreditation from the ASME (The American Society of Mechanical Engineers) in ASME B31.3 Process Piping Design, ASME BPV Code, Section V111, Division 1, and API 579-1/ASME FFS-1 Fitness-for-Service.

The author has delivered technical presentations on detail engineering and layout of piping systems in the USA, Trinidad and Tobago BWI.

Introduction

This book is aimed at not only being an introduction, but an extension and further enhancement of advanced explanations covering the many facets of detail engineering and layout of plant and piping systems. The material progresses through each of the major design processes, starting with the basics of plant layout design, equipment sizing and layout, pumps and exchanger layouts, maintenance requirements, process and utility piping, pipe supports and ending with pipe sizing, and pipe stress analysis. The book concentrates not only on the design aspects, but also on the practical aspects of plant and piping layout, using design examples to illustrate the points of design, and show the maintenance, operational, and safety aspects required in designing and building a process plant facility.

The objective of this book is to focus on how to design and build a process plant and its associated piping, that is safe, operable, maintainable, and economical.

Detail engineering of process piping plants consists of the engineering, design, detail and layout of process and utility equipment, piping, and instrumentation. The objective is to enhance the understanding of detail engineering and layout of piping systems, for people employed in any area that process piping is present, be it refinery, chemical, power, pulp and paper, mining, pharmaceutical or utilities, etc. It will enhance the knowledge of engineers, designers and construction personnel in the various procedures involved in the development and engineering of Piping and Instrumentation Diagrams (P&IDs), Equipment Plot Plans, Piping Arrangements and Fabrication Drawings.

The design practices that have been incorporated into the course are in compliance with procedures developed in the petroleum industry and that comply with ASME B31.3 Code.

This will include pipe sizing, pressure drop calculations, pump and equipment sizing and selection, preparation of equipment specifications and drawings, piping specifications, instrumentation and process control, as well as piping component familiarization including valves and fittings, piping hangers, and supports.

This book will bring a greater understanding to engineers, designers, operations, and construction personnel with regard to layout, design procedures, and practices involved in the location of equipment and layout of piping systems for industrial and oil and gas facilities.

In the past, there was very little formal training in the area of plant design and process piping design. Decisions were made based on practical considerations without formulae or code reinforcement.

This has now changed with the introduction of industry codes and practices mainly implemented by ASME (American Society of Mechanical Engineers) in the United States, and by PED (Pressure Equipment Directive) in Europe, and by organizations such as the Energy Institute in the UK, API (American Petroleum Institute), NACE (National Association of Corrosion Engineers), and NFPA (National Fire Protection Association) in the USA.

The production of piping arrangement drawings and piping isometrics, takes up the majority of man-hours in the design of a process plant and the engineer is required to apply acceptable safe, maintainable, operable, and economic layout procedures to achieve this.

This book will give engineers the background required to produce the necessary detail engineering documents required to design and layout process plants including plot plans, equipment and piping drawings, and the necessary calculations required to achieve this.

CHAPTER

Engineers and designers—Career paths—Institutes

1

The terminology dimensional, temperature, pressure, etc. used throughout this book is shown in both metric and imperial (English units) notations. There are however some instances where the notation might be shown only in metric, and in other instances where it might be only shown in imperial (English units). This was done for the clarity of the particular calculation, and the fact that the book would be read by engineers in countries using both or either metric or imperial systems.

1.1 WHAT IS A PIPING/PLANT LAYOUT DESIGNER AND ENGINEER

ENGINEER

The engineer is the person in charge of the engineering design of a plant and/or of a piping system. He or she shall be experienced in the design principles of piping and plant layout design, stress analysis, materials, and pipe support design, along with a thorough understanding of the ASME B31.3 code for pressure piping. The engineer shall also be responsible for the checking and approval of all design work produced by the designer.

DESIGNER

The designer is the person responsible for the piping design and layout of a plant and/or piping system with emphasis on the detailed design. He or she shall be responsible for the ownership and lead of a design area or areas on a project, along with the detailed design and layout of equipment and piping general arrangement drawings, piping isometric drawings, and pipe support details.

ENGINEERS

Engineers need the completion of (minimum) a bachelor's degree in mechanical engineering or an HNC/HND (Higher National Certificate/Diploma) followed by an extra year of learning, to bring up to degree status. Engineers require a minimum 4 years of study, plus 10 years of experience in the design of related pressure piping.

To gain Professional Engineer registration in the United Kingdom and its territories, the following are the requirements:

Chartered Engineer (CEng)—requires a master's degree in mechanical engineering and appropriate years of experience, plus the membership of a professional institution such as but not limited to:

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https://doi.org/10.1016/B978-0-12-814653-8.00001-1

- The Institution of Mechanical Engineers
- The Institute of Engineering Technology
- The Institution of Plant Engineers
- The Energy Institute

Incorporated Engineer (IEng)—requires a bachelor's degree or an HNC/HND (with an additional year of study) in mechanical engineering, and appropriate years of experience, plus the membership of a professional institution such as but not limited to:

- The Institution of Mechanical Engineers
- The Institute of Engineering Technology
- The Institution of Plant Engineers
- The Energy Institute

To gain Professional Engineer registration in the United States an accredited 4-year degree in mechanical engineering, plus study for the engineer in training exams which must be passed to satisfy the requirements of the professional engineering board depending on the state that the engineer is to practice in.

To gain Professional Engineer registration in any other country you must consult the relevant Board of Engineering for the country you live in.

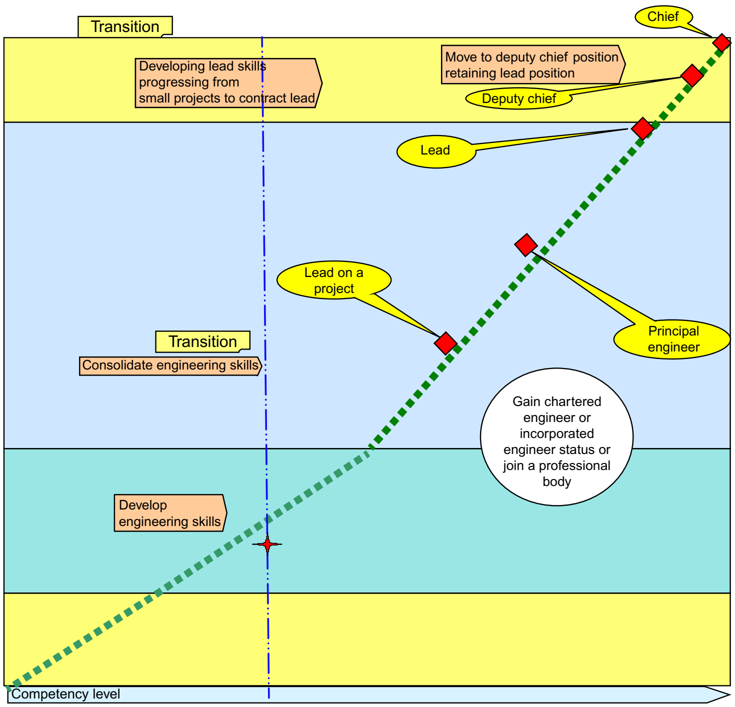

FIG. 1.1

Timeline to gain Incorporated or Chartered Engineer status.

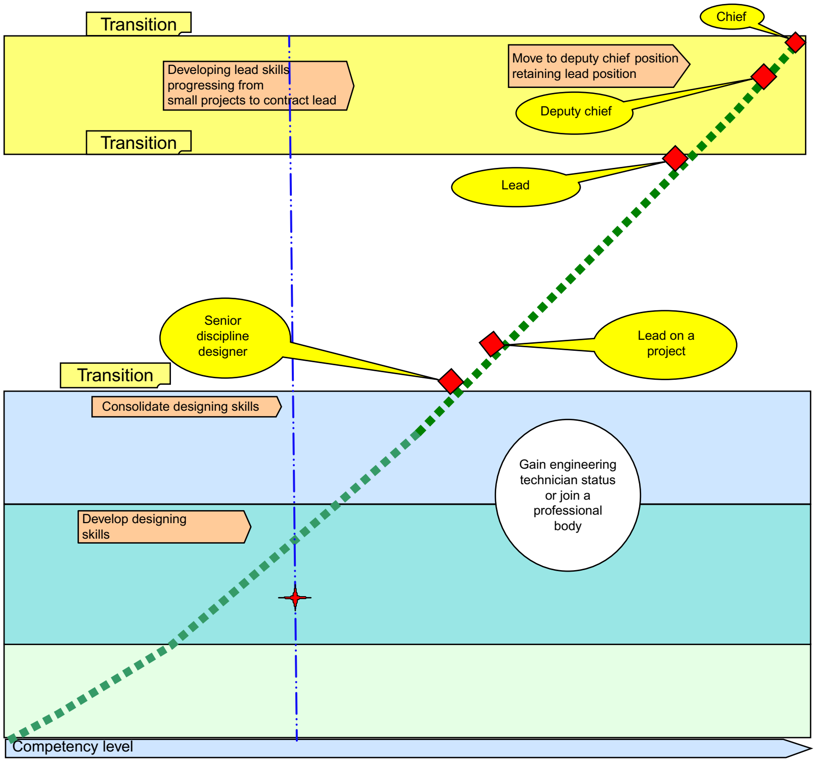

FIG. 1.2

Timeline to gain Engineering Technician status.

DESIGNERS

Require the completion of an accredited engineering technician or associates degree, or an ONC/OND (Ordinary National Certificate/Diploma, NVQ qualification or equivalent), requiring at least 2 years of study, plus a minimum of 10 years of experience in the design of related pressure piping.

To gain Engineering Technician registration in the United Kingdom and its territories, the following are the requirements:

Engineering Technician (EngTech)—an ONC/OND (Ordinary National Certificate or Diploma) in Mechanical Engineering and appropriate years of experience, plus the membership of a professional institution such as but not limited to:

- The Institution of Mechanical Engineers
- The Institute of Engineering Technology

- The Institution of Plant Engineers
- The Energy Institute

To gain Engineering Technician registration in any other country you must consult the relevant Board of Engineering Technicians for the country you live in.

1.2 ENGINEERING INSTITUTIONS AND ENGINEERING SOCIETIES

AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME)

The ASME was founded in 1880 to provide a setting for engineers to discuss the concerns brought about by industrialization and mechanization. ASME is the leading international developer of codes and standards associated with the art, science, and practice of mechanical engineering. ASME started with the first issuance of its legendary Boiler and Pressure Code in 1914. These codes have now grown to nearly 600 offerings currently in print.

A major benefit of being an ASME member is to further your professional career, and to connect with the best minds in engineering, advance your career, and make a difference by getting involved. Joining ASME's community of engineers enables you to learn new technologies, keep your skills up to date, explore solutions to technical problems, and to advance your career. As an ASME member, you can take advantage of extensive professional and student benefits, most of which are available at no additional cost or at a substantial discount. ASME membership gives you the tools, professional training, information, and connections you need to succeed at every step of your career. Joining ASME is one of the most important connections a mechanical engineer can make. Members enjoy a host of valuable benefits, plus the opportunity to have a direct impact on the engineering field.

THE INSTITUTION OF PLANT ENGINEERS (IPlantE), THE SOCIETY OF OPERATIONS ENGINEERS (SOE)

The IPlantE (Institution of Plant Engineers) was founded in 1946 and is the professional sector for people whose engineering skills are typically used in industrial, manufacturing, military, and utility processes for ensuring machinery and equipment can be operated safely, efficiently, and in an environmentally sustainable way.

The institution helps its members develop their skills, share best practices, and demonstrate their professional competence—for current and prospective employers, engineering service providers, plant and equipment owners, or the community at large.

It also owns www.plantengineer.org.uk, a definitive online resource for plant engineers and technicians containing the latest industry news, jobs, and a comprehensive supplier directory. The SOE along with IPlantE runs a variety of seminars on current legislations.

THE INSTITUTE OF MECHANICAL ENGINEERS (IMechE)

The IMechE was started in 1847, holding its first meetings in Birmingham, UK.

The present headquarters of the IMechE, 1 Birdcage Walk in London was completed in 1899.

Two of IMechE's famous past presidents.

FIG. 1.3

George Stephenson.

From The Project Gutenberg eBook, Great Britain and Her Queen, by Anne E. Keeling http://www.gutenberg.org/etext/13103. Taken from https://en.wikipedia.org/wiki/George_Stephenson#/media/File:George_Stephenson_Project_Gutenberg_etext_13103.jpg.

FIG. 1.4

Joseph Whitworth.

Photograph of a portrait of Joseph Whitworth, engineer. Taken from https://commons.wikimedia.org/wiki/File:Joseph_Whitworth.jpg.

THE INSTITUTE OF MECHANICAL ENGINEERS (IMECHE)

The IMechE supports product innovation, developing a nation's economic growth and increasing its global trade. Through government campaigns such as Engineered in Britain, this institute shows that a growing and thriving manufacturing sector will provide future economic growth, wealth, and prosperity.

The institute promotes safe, efficient transport systems to ensure less congestion and emissions. To advance, travel must be made cleaner, safer, and easier, which means creating a better understanding of global transport supply and demand, while keeping a sharp focus on the implications on carbon emissions.

The **IMechE** promotes sustainable energy use and engineering sustainable supply. The institutes need to share knowledge, changes the way we behave and drives advances in technology to reduce the strain on the world's resources, and champions the development of more sustainable sources of energy which will also help reduce emissions.

The **IMechE** inspires, prepares, and supports tomorrow's engineers so that they can respond to society's challenges.

THE ENERGY INSTITUTE (EI) (FORMERLY THE INSTITUTE OF PETROLEUM)

The purpose of the Energy Institute is to develop and disseminate knowledge about energy in all its forms and applications, and to enhance public understanding of energy resources and their role in society.

The institute publishes magazines and technical publications to promote knowledge and good practice across the whole spectrum of energy supply and use.

Energy professionals can keep themselves up to date with the latest developments within the industry through its programs or events providing access to the latest thinking from industry leaders and fellow energy specialists.

The **EI** provides a wide range of industry information through its lbrary services providing access to e-publications and journals, in-depth statistics as well as a physical stock of 15,000 books held at its premises, and has an education portal covering all aspects of energy, which also provides career advice for students and professional development guidance for existing employees within the industry.

For most energy professionals, the ultimate aim of membership will be professional recognition. Professional members come from a very wide range of energy backgrounds.

The **EI** can offer you an **EI** grade of professional membership along with a number of different professional registrations appropriate to your specialism:

Professional membership (fellow, member, or technician member)
Engineering registration (CEng, IEng, or EngTech)
Chartered Scientist registration (CSci)
Chartered Environmentalist registration (CEnv)
Chartered Energy Engineer or Chartered Petroleum Engineer (unique to EI)
Chartered Energy Manager (unique to EI)

THE INSTITUTE OF ENGINEERING AND TECHNOLOGY (IET)

Sources your essential engineering intelligence from the five sectors:

Accesses expertise, finds current and reliable information, participates in active communities, and attends industry'leading events via the institute's five sectors: Built Environment, Design and Production, Energy, Information and Communications, and Transport.

This **Institute of Engineering and Technology** is the largest and broadest engineering institution in Europe offering professional development, communities, and knowledge services to engineers and technicians working in multidisciplinary environments. Our 150,000 members across the globe regard this institution as their professional home for life.

As with other institutions, the **IET** provides:

Professional development
Professional registration
Career management
Technical and professional networks
Lectures, seminars, and conferences
Magazines, books, a library, and archives

CHAPTER

Piping material, process terms, and piping codes

2

2.1 PIPING MATERIALS

DESIGN AS ADDRESSED IN ASME B31.3 CHAPTER II—DESIGN

ASME B31.3 Chapter II—Design, clearly outlines the requirements for engineers and designers along with the aspects required for the design of process piping systems. It is up to the reader to read and fully understand the ASME code by obtaining and reading the latest release of B31.3 and to use always this as a basis of design by adhering to the code.

In ASME B31.3 code Chapter II—*Design*, the code states that the ***design conditions*** define temperatures, pressures, and forces applicable to the design of piping, and continues to state that consideration shall be given to various effects and their consequent loadings. It is therefore up to the reader when designing piping systems to take the code into consideration, and it is important that the code is fully understood and implemented when designing these systems.

Chapter II of the **code** also addresses the ***Qualifications of the Designer***, it states:

"The designer is the person(s) in charge of the engineering design of a piping system and shall be experienced in the use of this code. The qualifications and experience required of the designer will depend on the complexity and criticality of the system and the nature of the individual's experience. The owner's approval is required if the individual does not meet at least one of the following criteria:

(a) Completion of an ABET accredited or equivalent engineering degree, requiring the equivalent of at least 4 years of study, plus a minimum of 5 years of experience in the design of related pressure piping.

(b) Professional engineering registration, recognized by the local jurisdiction, and experience in the design of related pressure piping.

(c) Completion of an accredited engineering technician or associates degree, requiring the equivalent of at least 2 years of study, plus a minimum of 10 years of experience in the design of related pressure piping.

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https://doi.org/10.1016/B978-0-12-814653-8.00002-3

(d) Fifteen years of experience in the design of related pressure piping. Experience in the design of related pressure piping is satisfied by piping design experience that includes design calculations for pressure, sustained and occasional loads, and piping flexibility."

ASME B31.3 Chapter II Design addresses the following topics as shown below, and the reader must read and familiarize themselves with the contents and be able to implement these considerations when designing piping systems:

- **Conditions and criteria**
  - Design conditions
  - Design criteria
- **Pressure design of piping components**
  - General
  - Pressure design of components
- **Fluid service requirements for piping components**
  - Pipe
  - Fittings, bends, miters, laps, and branch connections
  - Valves and specialty components
  - Flanges, blanks, flange facings, gaskets and bolting
- **Fluid service requirements for piping joints**
  - General
  - Welded joints
  - Flanged joints
  - Expanded joints
  - Threaded joints
  - Tubing joints
  - Caulked joints
  - Soldered and brazed joints
  - Special joints
- **Flexibility and support**
  - Piping flexibility
  - Piping support
- **Systems**
  - Specific piping systems

I refer the reader to look at the following tables in the latest edition of ASME B31.3:

- Longitudinal weld joint quality factors
- Increasing casting quality factors
- Acceptance level for castings
- Stress range factors

I also refer the reader to read the sections on limits of calculated stresses due to sustainable loads and displacement strains.

The engineer will have to refer to these tables during the design process.

STANDARDS AS ADDRESSED IN ASME B31.3 CHAPTER IV FOR PIPING COMPONENTS

ASME Chapter IV addresses, ASME B31.3 Standards for Piping Components.

The reader should pay particular attention to following sections and read and understand their applications:

- Table for weld joint strength reduction factors
- Table for component standards

The reader should also read and familiarize themselves with the following paragraphs in Chapter IV Standards for Piping Components:

- Under the paragraph heading: **dimensional requirements**
  - Listed piping components
  - Unlisted piping components
  - Threads
- Under the paragraph, heading; **rating of components**
  - Listed components
  - Unlisted components
  - Reference documents

As you can see from the list of topics mentioned in ASME B31.3 Chapter IV for Piping Components, it is important that the reader familiarize themselves with the content of not only this chapter but also the complete B31.3 publication, and refer to it constantly when designing piping systems.

METHODS OF MANUFACTURING PIPE

When we talk about piping materials we not only mean pipe, but also fittings, flanges and valves, blinds, rupture disks, bolts, nuts, etc. In other words, everything that is associated with pipe.

All these items have to be of the correct material suitable for the project and must meet code requirements. Metallic piping is divided into two classes: ferrous and nonferrous.

Ferrous materials are those of containing or derived from iron, and are most commonly used in process piping.

Ferrous metals are carbon steel, stainless steel, chrome steel, cast iron, etc.

Nonferrous metals include aluminum.

The following table shows some examples of steel pipe specifications.

Table 2.1 Some Steel Pipe Specifications

ASTM Number	Type	Material	Remarks
A53	Gr. A, B	Carbon Steel	Manufactured in welded and seamless, Grade B is most commonly specified
A-106	Gr. A, B	Carbon Steel	Seamless, Grade B is preferred and mostly used. Most modern plants have carbon steel pipe of this specification.
A-333	Gr.1	Carbon Steel	Used in subzero temperatures, and incorporates special testing, for use to −45°C (−50°F)
A-335	P1	Carbon Moly	Carbon Steel with 1/2% molybdenum, used in high temperature service
A-335	P11	Carbon Moly	1 1/4% chrome,1/2% molybdenum, used in higher temperatures and corrosive service
A-335	P5	Carbon Moly	5% chrome,1/2% molybdenum, used in higher temperature, corrosive services
A-335	P9	Carbon Moly	9% chrome, 1% molybdenum, used in high temperature highly corrosive services
A-312	304	Stainless	Used for temperatures below −45°C (−50°F) and for corrosive service at higher temperatures. Widely used for food product hygienic service piping.
A-312	316	Stainless	Used for high temperature, high corrosive service
A-312	321	Stainless	Used for very high temperature, highly corrosive service
A-312	347	Stainless	Used in harsher conditions than type 321 stainless steel
A-333	Gr.3	Nickel	3 1/2% nickel, used for temperatures from −45°C (−50°F) to −101°C (−150°F)

Pipe diameter, wall thickness, material specification, and delivery requirements are determining factors in the selection of the manufacturing process.

Steel pipe is made by lap-welding, spiral welding, butt welding, and seamless methods.

Welded pipe types are made from flat plates which are rolled to form round shapes, the edges are then welded together to form a longitudinal weld.

The longitudinal weld reduces the pressure-containing characteristics of pipe and the ANSI (American National Standards Institute) piping codes reduces the allowable stress of this method of manufacture by imposing a “joint efficiency” of less than 100%.

Seamless pipe has a joint efficiency of 100%, since there is no longitudinal joint.

Seamless pipe is made by extruding through a mold. The metal pipe is poured in a semimolten state through a mold and forced out of the other side.

Welded pipe can also attain this 100% joint efficiency rating with special quality control procedures such as stress relieving and full x-ray examination. These add to the cost though and may not be needed. In smaller sizes, seamless piping is often as economical as welded if 100% joint efficiency is specified. Whatever method of manufacture is specified, a "mill tolerance" must be added to the minimum calculated wall thickness. Plate is manufactured to a tolerance of 0.01″. Pipe that is made from plate (i.e., all pipe with a longitudinal seam) will have 0.01″ added to its calculated minimum thickness for this mill tolerance.

Seamless pipe is made by a process that requires a tolerance of 12 ½%. Seamless pipe is made from hot, round solid billets of steel. A mandrel is centered and penetrates the hot billet, expanding the solid piece to a hollow pipe.

This method can cause possible thin spots in the pipe wall: consequently, the 12 ½% mill tolerance is imposed. The tables show commercial wrought steel pipe data.

PIPE DIAMETERS, THICKNESSES, AND SCHEDULES

Table 2.2 The Charts Shows Commercial Wrought Pipe Data

Pipe Size	OD in Inches	5S	5	10S	True 10	20	30	40S & STD	True 40	60	80S & XS	True 80	100	120	140	160	XXS
1/8	.405		.035 .1383	.049 .1863	.049 .1863			.068 .2447	.068 .2447		.095 .3145	.095 .3145					
1/4	.540		.049 .2570	.065 .3297	.065 .3297			.088 .4248	.088 .4248		.119 .5351	.119 .5351					
3/8	.675		.049 .3276	.065 .4235	.065 .4235			.091 .5676	.091 .5676		.126 .7388	.126 .7388					
1/2	.840	.065 .5383	.065 .5383	.083 .6710	.083 .6710			.109 .8510	.109 .8510		.147 1.088	.147 1.088				.187 1.304	.294 1.714
3/4	1.050	.065 .6838	.065 .6838	.083 .8572	.083 .8572			.113 1.131	.113 1.131		.154 1.474	.154 1.474				.218 1.937	.308 2.441
1	1.315	.065 .8678	.065 .8678	.109 1.404	.109 1.404			.133 1.679	.133 1.679		.179 2.172	.179 2.172				.250 2.844	.358 3.659
1-1/4	1.660	.065 1.107	.065 1.107	.109 1.806	.109 1.806			.140 2.273	.140 2.273		.191 2.997	.191 2.997				.250 3.765	.382 5.214
1-1/2	1.900	.065 1.274	.065 1.274	.109 2.085	.109 2.085			.145 2.718	.145 2.718		.200 3.631	.200 3.631				.281 4.859	.400 6.408
2	2.375	.065 1.604	.065 1.604	.109 2.638	.109 2.638			.154 3.653	.154 3.653		.218 5.022	.218 5.022				.344 7.462	.436 9.029
2-1/2	2.875	.083 2.475	.083 2.475	.120 3.531	.120 3.531			.203 5.793	.203 5.793		.276 7.661	.276 7.661				.375 10.01	.552 13.70
3	3.500	.083 3.029	.083 3.029	.120 4.332	.120 4.332			.216 7.576	.216 7.576		.300 10.25	.300 10.25				.438 14.32	.600 18.58
3-1/2	4.000	.083 3.472	.083 3.472	.120 4.937	.120 4.937			.226 9.109	.226 9.109		.318 12.51	.318 12.51					.636 22.85
4	4.500	.083 3.915	.083 3.915	.120 5.613	.120 5.613			.237 10.79	.237 10.79		.337 14.98	.337 14.98		.438 19.00		.531 22.51	.674 27.54
5	5.563	.109 6.349	.109 6.349	.134 7.770	.134 7.770			.258 14.62	.258 14.62		.375 20.78	.375 20.78		.500 27.04		.525 32.96	.750 38.55
6	6.625	.109 7.585	.109 7.585	.134 9.289	.134 9.289			.280 18.97	.280 18.97		.432 28.57	.432 28.57		.562 36.39		.719 43.35	.864 53.16
8	8.625	.109 9.914	.109 9.914	.148 13.40	.148 13.40	.250 22.36	.277 24.70	.322 28.55	.322 28.55	.406 35.64	.500 43.39	.500 43.39	.594 50.95	.719 60.71	.812 67.76	.906 74.79	.875 72.42
10	10.75	.134 15.19	.134 15.19	.165 18.65	.165 18.65	.250 28.04	.307 34.24	.365 40.48	.365 40.48	.500 54.74	.500 54.74	.594 64.43	.719 77.03	.844 82.29	1.000 104.1	1.125 115.6	1.000 104.1
12	12.75	.156 21.07	.165 22.18	.180 24.18	.180 24.18	.250 33.38	.330 43.77	.375 49.56	.406 53.52	.562 73.15	.500 66.42	.688 83.63	.844 107.3	1.000 125.5	1.125 136.7	1.312 160.3	1.000 125.5
14	14.00	.156 23.07		.188 27.73	.250 36.71	.312 45.61	.375 54.57	.375 54.57	.438 63.44	.594 85.05	.500 72.09	.750 106.1	.938 130.9	1.094 150.8	1.250 170.2	1.406 189.1	
16	16.00	.165 27.90		.188 31.75	.250 42.05	.312 52.27	.375 62.58	.375 62.58	.500 82.77	.656 107.5	.500 82.77	.844 136.6	1.031 164.8	1.219 192.4	1.438 223.6	1.594 245.3	
18	18.00	.165 31.43		.188 35.76	.250 47.39	.312 58.94	.438 82.15	.375 70.59	.562 104.7	.750 138.2	.500 93.45	.938 170.9	1.156 208.0	1.375 244.1	1.562 274.2	1.781 308.5	
20	20.00	.188 39.78		.218 46.05	.250 52.73	.375 78.60	.500 104.1	.375 78.60	.594 123.1	.812 166.4	.500 104.1	1.031 208.9	1.281 256.1	1.500 296.4	1.750 341.1	1.969 379.2	
24	24.00	.218 55.37		.250 63.41	.250 63.41	.375 96.42	.562 140.7	.375 94.62	.688 171.3	.969 238.4	.500 125.5	1.219 296.6	1.531 367.4	1.812 429.4	2.062 483.1	2.344 542.1	
26	26.00				.312 85.60	.500 136.17		.375 102.63			.500 136.17						
28	28.00				.312 92.26	.500 146.85	.625 182.73	.375 110.64									
30	30.00	.250 79.43		.312 98.93	.312 98.93	.500 157.53	.625 196.08	.375 118.65			.500 157.53						
32	32.00				.312 105.59	.500 168.21	.625 209.43	.375 126.66	.688 230.08		.500 168.21						
34	34.00				.312 112.25	.500 178.89	.625 222.78	.375 134.67	.688 244.77								
36	36.00				.312 118.92		.625 236.13	.375 142.68	.750 282.35		.500 189.57						

BLACK = Wall thickness in inches

RED = Steel weight per foot in pounds*

*To calculate the weight for the alloys below, multiple the weight per foot from the chart with these factors...

ALLOY 200 1.1343
ALLOY 400 1.1272
ALLOY 600 1.0742
ALLOY 825 1.0389
ALLOY 800 1.0247
ALLOY 020 1.0220

Information provided is for reference only and is not to be used as a sole source for design or application purposes.

FITTINGS AND FLANGES

FIG. 2.1

Fittings

Welded fittings are manufactured to match the companion pipe. But it is not mandatory that the fitting and the pipe have the same thickness. Pipe is available in various schedules, but fittings are not stocked for all schedules. Fittings are usually specified as standard weight, extra strong, schedule 160, and double extra strong. It is usually advantageous to specify the fitting thickness of the next higher available weight if the pipe wall thickness is not standard, extra strong, etc.

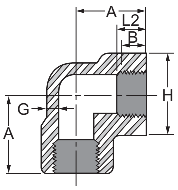
For pipe sizes 2″ and below, welded fittings are not usually used. For low pressure, noncritical service, screwed fittings are specified, while for higher pressures and most process systems, socket weld fittings are specified.

FIG. 2.2

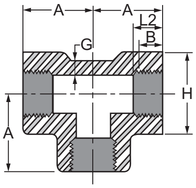
FIG. 2.3

Screwed fittings.

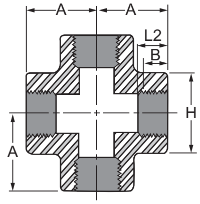
Table 2.3



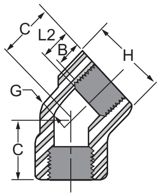
90° Elbow



Tee



Cross



45° Elbow

DN	Nom. pipe size	Center to end elbow, tee, cross A			Center to end 45° elbow C			Outside diameter of band H			Minimum wall thickness G			Length of thread min. (1)	
		2000	3000	6000	2000	3000	6000	2000	3000	6000	2000	3000	6000	B	L2
6	1/8"	21	21	25	17	17	19	22	22	25	3.18	3.18	6.35	6.4	6.7
8	1/4"	21	25	28	17	19	22	22	25	33	3.18	3.30	6.60	8.1	10.2
10	3/8"	25	28	33	19	22	25	25	33	38	3.18	3.51	6.98	9.1	10.4
15	1/2"	28	33	38	22	25	28	33	38	46	3.18	4.09	8.15	10.9	13.6
20	3/4"	33	38	44	25	28	33	38	46	56	3.18	4.32	8.53	12.7	13.9
25	1"	38	44	51	28	33	35	46	56	62	3.68	4.98	9.93	14.7	17.3
32	1-1/4"	44	51	60	33	35	43	56	62	75	3.89	5.28	10.59	17.0	18.0
40	1-1/2"	51	60	64	35	43	44	52	75	84	4.01	5.56	11.07	17.0	18.4
50	2"	60	64	83	43	44	52	75	84	102	4.27	7.14	12.09	19.0	19.2
65	2-1/2"	76	83	95	52	52	64	92	102	121	5.61	7.65	15.29	23.6	28.9
80	3"	86	95	106	64	64	79	109	121	146	5.99	8.84	16.64	25.9	30.5
100	4"	106	114	114	79	79	79	146	152	152	6.55	11.18	18.67	27.7	33.0

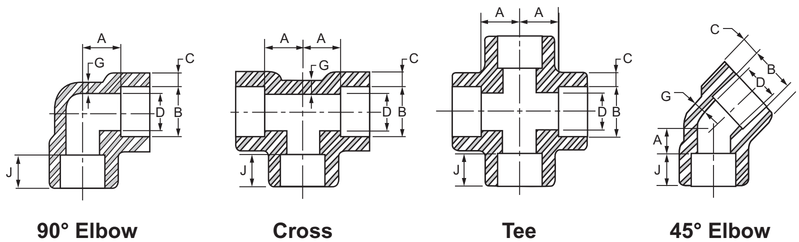
(1) Dimensions in millimeters.

(2) Dimension B is minimum length of perfect thread. The length of useful thread (B plus threads with fully formed roots and flat crests) shall not be less than L2 (effective length of external thread) required by American National Standard for pipe threads (ANSI/ASME B1.20.1)

FIG. 2.4

Table 2.4

Socket weld fittings



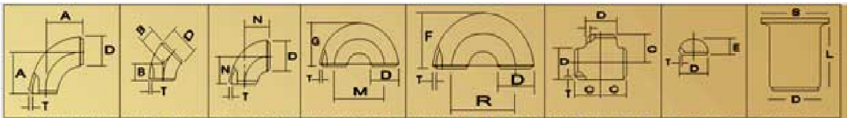
DN	Nom. pipe size	Center to bottom of socket-A						Socket bore dia.	Bore dia. of fitting D			Socket wall thickness (2) C						Body wall thickness G			Depth of socket min. J
		90° Elbows tees, crosses			45° Elbows							Class designation						Class designation			
		Class designation			Class designation				Class designation			3000		6000		9000		3000	6000	9000	
		3000	6000	9000	3000	6000	9000	B	3000	6000	9000	Ave.	Min.	Ave.	Min.	Ave.	Min.	Min.	Min.	Min.	
6	1/8"	11.0	11.0		8.0	8.0		10.8	6.9	4.0		3.18	3.18	3.96	3.43			2.41	3.15		9.5
8	1/4"	11.0	13.5		8.0	8.0		14.2	9.3	6.4		3.78	3.30	4.60	4.01			3.02	3.68		9.5
10	3/8"	13.5	15.5		8.0	11.0		17.6	12.6	9.2		4.01	3.50	5.03	4.37			3.20	4.01		9.5
15	1/2"	15.5	19.0	25.5	11.0	12.5	15.5	21.8	15.8	11.8	6.4	4.67	4.09	5.97	5.18	9.35	8.18	3.73	4.78	7.47	9.5
20	3/4"	19.0	22.5	28.5	13.0	14.0	19.0	27.2	21.0	15.6	11.1	4.90	4.27	6.96	6.04	9.78	8.56	3.91	5.56	7.82	12.5
25	1"	22.5	27.0	32.0	14.0	17.5	20.5	33.9	26.7	20.7	15.2	5.69	4.98	7.92	6.93	11.38	9.96	4.55	6.35	9.09	12.5
32	1-1/4"	27.0	32.0	35.0	17.5	20.5	22.5	42.7	35.1	29.5	22.8	6.07	5.28	7.92	6.93	12.14	10.62	4.85	6.35	9.70	12.5
40	1-1/2"	32.0	38.0	38.0	20.5	25.5	25.5	48.8	40.9	34.0	28.0	6.35	5.54	8.92	7.80	12.70	11.12	5.08	7.14	10.15	12.5
50	2"	38.0	41.0	54.0	25.5	28.5	28.5	61.2	52.5	42.9	38.2	6.93	6.04	10.92	9.50	13.84	12.12	5.54	8.74	11.07	16.0
65	2-1/2"	41.0			28.5			73.9	62.7			8.76	7.67					7.01			16.0
80	3"	57.0			32.0			89.8	78.0			9.52	8.30					7.62			16.0
100	4"	66.5			41.0			115.2	102.3			10.69	9.35					8.56			19.0

(1) Dimensions in millimeters.
(2) Average of socket wall thickness around periphery shall be no less than listed values. The minimum values are permitted in localized areas.
(3) Upper and lower values for each size are the respective maximum and minimum dimensions.

FIG. 2.5

Butt weld fittings.

Table 2.5



BUTT WELDING PIPE FITTING DIMENSIONAL STANDARD ANSI B-16.9, B-16.28 & MSS SP 43

Nominal Pipe Size		Outside Diameter	Center to Face				Back to Face			Center to Center			Length 'L' MSSSP43	B16.9
Inch	mm	D	A	B	C	N	E	F	G	R	M	S	L	L
1/2	15	21.3	38.00	16.0	25.0	_	25.0	48.0	_	76.0		35.0	50.8	76.2
3/4	20	26.7	29.00	11.0	29.0	_	25.0	43.0	_	57.0		43.0	50.8	76.2
1	25	33.4	38.00	22.0	38.0	25.0	38.0	56.0	41.0	76.0	51.0	51.0	50.8	101.6
1.1/4	32	42.2	48.00	25.0	48.0	32.0	38.0	70.0	52.0	95.0	64.0	64.0	50.8	101.6
1.1/2	40	48.3	57.15	29.0	57.0	38.0	38.0	83.0	62.0	114.0	76.0	73.0	50.8	101.6
2	50	60.3	76.00	35.0	64.0	51.0	38.0	106.0	81.0	152.0	102.0	93.0	63.5	152.4
2.1/2	65	73	95.25	44.0	76.0	64.0	38.0	132.0	100.0	191.0	127.0	105.0	63.5	152.4
3	80	88.9	114.30	51.0	86.0	76.0	51.0	159.0	121.0	229.0	152.0	127.0	63.5	152.4
3.1/2	90	1016	133.35	57.0	95.0	89.0	64.0	184.0	140.0	267.0	178.0	140.0	76.2	152.4
4	100	114.3	152.0	63.0	105.0	102.0	64.0	210.0	159.0	305.0	203.0	157.0	76.2	152.4
5	125	141.3	190.0	79.0	123.0	127.0	76.0	262.0	197.0	381.0	254.0	186.0	76.2	203.2
6	150	168.3	229.0	95.0	143.0	152.0	89.0	313.0	237.0	457.0	305.0	216.0	88.9	203.2
8	200	219.1	305.0	127.0	178.0	203.0	102.0	414.0	313.0	610.0	406.0	270.0	101.6	203.2
10	250	273.1	381.0	159.0	216.0	254.0	127.0	515.0	391.0	762.0	508.0	324.0	127	254
12	300	323.9	457.0	190.0	254.0	303.0	152.0	619.0	467.0	914.0	610.0	381.0	152.4	254
14	350	355.6	533.0	222.0	279.0	356.0	165.0	711.0	533.0	1067.0	711.0	413.0	152.4	305.0
16	400	406.4	610.0	254.0	305.0	406.0	178.0	813.0	610.0	1219.0	813.0	470.0	152.4	305.0
18	450	457.2	686.0	286.0	343.0	457.0	203.0	914.0	686.0	1372.0	914.0	533.0	152.4	305.0
20	500	508	762.0	318.0	381.0	508.0	229.0	1016.0	762.0	1524.0	1016.0	584.0	152.4	305.0
22	550	559	838.0	343.0	419.0	559.0	254.0	1118.0	838.0	1676.0	1118.0	614.4	152.4	305.0
24	600	610	914.0	381.0	432.0	610.0	267.0	1219.0	914.0	1829.0	1219.0	692.0	152.4	305.0
26	650	660	991.0	406.0	495.0	660.0	267.0							
28	700	711	1067.0	438.0	521.0	771.0	267.0							
30	750	762	1143.0	470.0	589.0	762.0	267.0							
32	800	813	1219.0	502.0	597.0	813.0	267.0							
34	850	864	1295.0	533.0	635.0	864.0	267.0							
36	900	914	1372.0	565.0	673.0	914.0	267.0							

Fittings and flanges

FIG. 2.6

Flanges

Flanges are manufactured as:

- Screwed
- Weld neck (regular and long weld neck)
- Slip-on
- Lap joint (stub ends)

Flanges are available in the following ratings:

- 150#, 300#, 400#,600#,900# and 1500#
- 2500#, 5000# and 10,000# flanges are also used in wellheads for high-pressure service

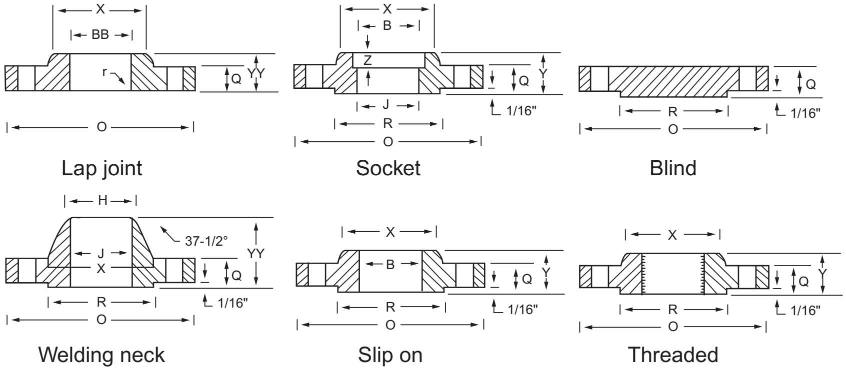


FIG. 2.7

Flange types.

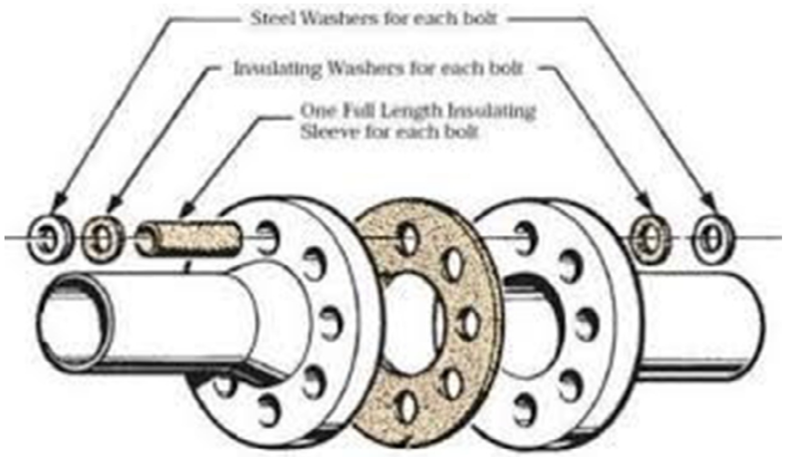


FIG. 2.8

Insulating Kit for Flanges

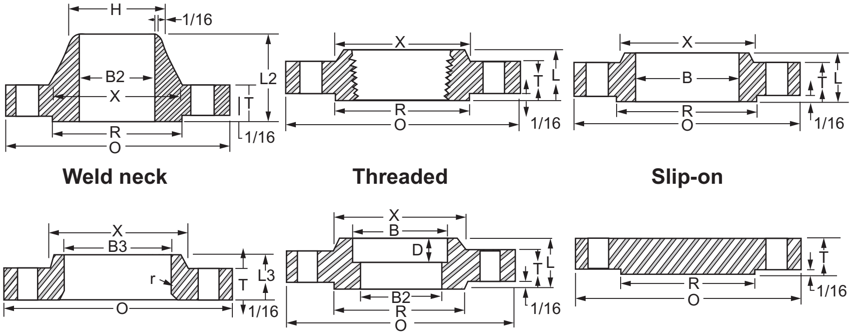
When connecting two flanges of dissimilar metals (e.g., stainless steel to carbon steel), it is necessary to use an insulating kit to isolate metal-to-metal contact between flanges, this will stop the dielectric effect and thus minimize corrosion.

Flange size and bolt tables

Table 2.6

Line Size Inches	Flange Rating All Dimensions in inches											
	150# SF 2.5		300# SF 2.5		600# SF 3.0		900# SF 3.0		1500# SF 3.0		2500# SF 3.0	
	O.D.	TKNS	O.D.	TKNS	O.D.	TKNS	O.D.	TKNS	O.D.	TKNS	O.D.	TKNS
1/2"	1 3/4	5/16	2	5/16	2	5/16	2 3/8	5/16	2 3/8	5/16	2 5/8	3/8
3/4"	2 1/8	5/16	2 1/2	5/16	2 1/2	5/16	2 5/8	5/16	2 5/8	3/8	2 7/8	3/8
1"	2 1/2	5/16	2 3/4	5/16	2 3/4	5/16	3	5/16	3	3/8	3 1/4	3/8
1 1/4"	2 7/8	5/16	3 1/8	5/16	3 1/8	3/8	3 3/8	3/8	3 3/8	3/8	4	1/2
1 1/2"	3 1/4	5/16	3 5/8	5/16	3 5/8	3/8	3 3/4	3/8	3 3/4	1/2	4 1/2	5/8
2	4	5/16	4 1/4	3/8	4 1/4	3/8	5 1/2	1/2	5 1/2	1/2	5 5/8	5/8
2 1/2"	4 3/4	5/16	5	3/8	5	1/2	6 3/8	1/2	6 3/8	5/8	6 1/2	3/4
3	5 1/4	5/16	5 3/4	3/8	5 3/4	1/2	6 1/2	5/8	6 3/4	3/4	7 5/8	7/8
3 1/2"	6 1/4	3/8	6 3/8	3/8	6 1/4	5/8						
4"	6 3/4	3/8	7	1/2	7 1/2	5/8	8	3/4	8 1/8	7/8	9 1/8	1 1/8
5"	7 5/8	3/8	8 3/8	5/8	9 3/8	3/4	9 5/8	7/8	9 7/8	1 1/8	10 7/8	1 3/8
6"	8 5/8	1/2	9 3/4	5/8	10 3/8	7/8	11	1	11	1 3/8	12 3/8	1 5/8
8"	10 7/8	1/2	12	7/8	12 1/2	1 1/8	14	1 3/8	13 3/4	1 5/8	15 1/8	2 1/8
10"	13 1/4	5/8	14 1/8	1	15 5/8	1 3/8	17	1 5/8	17	2	18 5/8	2 5/8
12"	16	3/4	16 1/2	1 1/8	17 5/8	1 5/8	19 1/2	1 7/8	20 3/8	2 3/8	21 1/2	3 1/8
14"	17 5/8	3/4	19	1 1/4	19 1/4	1 3/4	20 3/8	2 1/8	22 5/8	2 5/8		
16"	20 1/8	7/8	21 1/8	1 1/2	22 1/8	2	22 1/2	2 3/8	25 1/8	3		
18"	21 1/2	1	23 3/8	1 5/8	24	2 1/8	25	2 5/8	27 5/8	3 3/8		
20"	23 3/4	1 1/8	25 5/8	1 3/4	26 3/4	2 1/2	27 3/8	2 7/8	29 5/8	3 3/4		
22"	25 7/8	1 1/4	27 5/8	1 7/8	28 3/4	2 3/4						
24"	28 1/8	1 3/8	30 3/8	2	31	2 7/8	32 7/8	3 1/2	35 3/8	4 3/8		
* 26"	30 3/8	1 1/2	32 3/4	2	34	3 1/8	34 5/8	3 3/4				
* 28"	32 5/8	1 5/8	35 1/4	2 1/8	35 7/8	3 3/8	37 1/8	4 1/8				
* 30"	34 5/8	1 3/4	37 3/8	2 3/8	38 1/8	3 5/8	39 5/8	4 3/8				
* 32"	36 7/8	1 3/4	39 1/2	2 1/2	40 1/8	3 3/4	42 1/8	4 3/4				
* 34"	38 7/8	1 7/8	41 1/2	2 5/8	42 1/8	4 1/8	44 5/8	5				
* 36"	41 1/8	2	43 7/8	2 3/4	44 3/8	4 1/4	47 1/8	5 1/4				
* 38"	43 5/8	2 1/8	41 3/8	3	43 3/8	4 1/2	47 1/8	5 1/2				
* 40"	45 5/8	2 1/4	43 3/4	3 1/8	45 3/8	4 3/4	49 1/8	5 7/8				
* 42"	47 7/8	2 3/8	45 3/4	3 1/4	47 7/8	5	51 1/8	6 1/8				
* 44"	50 1/8	2 1/2	47 7/8	3 3/8	49 7/8	5 1/4	53 3/4	6 3/8				
* 46"	52 1/8	2 1/2	50	3 5/8	51 7/8	5 1/2	56 3/8	6 3/4				
* 48"	54 3/8	2 5/8	50	3 3/4	54 3/8	5 3/4	58 3/8	7				

ANSI B16.5 Class 150 Forged Flanges



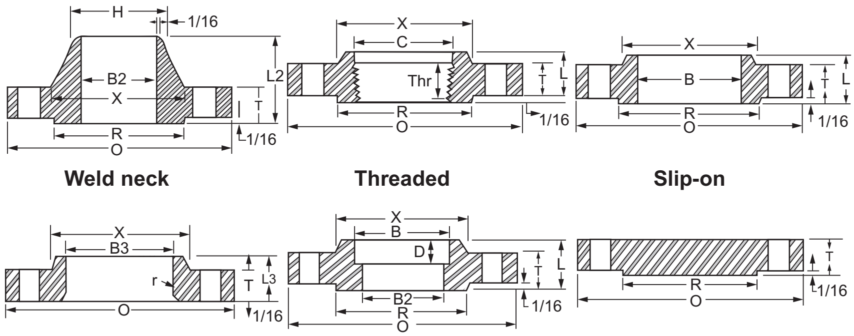
Weld neck Threaded Slip-on

Lap joint Socket weld Blind

Nom. pipe size	O	T_1	R	X	No.2/dia. of holes	Bolt circle dia.	$L2_1$	H	$B2_3$	L	B	r	$L3_4$	B3	D
½	3.5	.44	1.38	1.19	4-0.62	2.38	1.88	.84	.62	.62	.88	.12	.62	.9	.38
¾	3.88	.5	1.69	1.5	4-0.62	2.75	2.06	1.05	.82	.62	1.09	.12	.62	1.11	.44
1	4.25	.56	2	1.94	4-0.62	3.12	2.19	1.32	1.05	.69	1.36	.12	.69	1.38	.5
1¼	4.62	.62	2.5	2.31	4-0.62	3.5	2.25	1.66	1.38	.81	1.70	.19	.81	1.72	.56
1½	5	.68	2.88	2.56	4-0.62	3.88	2.44	1.9	1.61	.88	1.95	.25	.88	1.97	.62
2	6	.75	3.62	3.06	4-0.75	4.75	2.5	2.38	2.07	1	2.44	.31	1	2.46	.69
2½	7	.88	4.12	3.56	4-0.75	5.5	2.75	2.88	2.47	1.12	2.94	.31	1.12	2.97	.75
3	7.5	.94	5	4.25	4-0.75	6	2.75	3.5	3.07	1.19	3.57	.38	1.19	3.6	.81
3½	8.5	.94	5.5	4.81	8-0.75	7	2.81	4	3.55	1.25	4.07	.38	1.25	4.1	.88
4	9	.94	6.19	5.31	8-0.75	7.5	3	4.5	4.03	1.31	4.57	.44	1.31	4.6	.94
5	10	.94	7.31	6.44	8-0.88	8.5	3.5	5.56	5.05	1.44	5.66	.44	1.44	5.69	.94
6	11	1	8.5	7.56	8-0.88	9.5	3.5	6.63	6.07	1.56	6.72	.5	1.56	6.75	1.06
8	13.5	1.12	10.62	9.69	8-0.88	11.75	4	8.63	7.98	1.75	8.72	.5	1.75	8.75	1.25
10	16	1.19	12.75	12	12-1.00	14.25	4	10.75	10.02	1.94	10.88	.5	1.94	10.92	1.31
12	19	1.25	15	14.38	12-1.00	17	4.5	12.75	12	2.19	12.88	.5	2.19	12.92	1.56
14	21	1.38	16.25	15.75	12-1.12	18.75	5	14	13.25	2.25	14.14	.5	3.12	14.18	1.63
16	23.5	1.44	18.5	18	16-1.12	21.25	5	16	15.25	2.5	16.16	.5	3.44	16.19	1.75
18	25	1.56	21	19.88	16-1.25	22.75	5.5	18	17.25	2.69	18.18	.5	3.81	18.20	1.94
20	27.5	1.69	23	22	20-1.25	25	5.69	20	19.25	2.88	20.2	.5	4.06	20.25	2.13
22	29.5	1.81	25.25	24.25	20-1.38	27.25	5.88	22	21.25	3.13	22.22	.5	4.25	22.25	2.38
24	32	1.88	27.25	26.12	20-1.38	29.5	6	24	23.25	3.25	24.25	.5	4.38	24.25	2.50

Dimensions in inches.

ANSI B16.5 Class 300 Forged Flanges

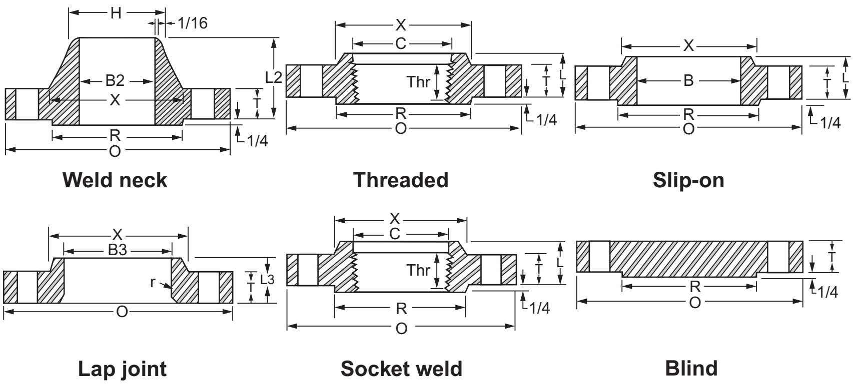


Weld neck — Threaded — Slip-on

Lap joint — Socket weld — Blind

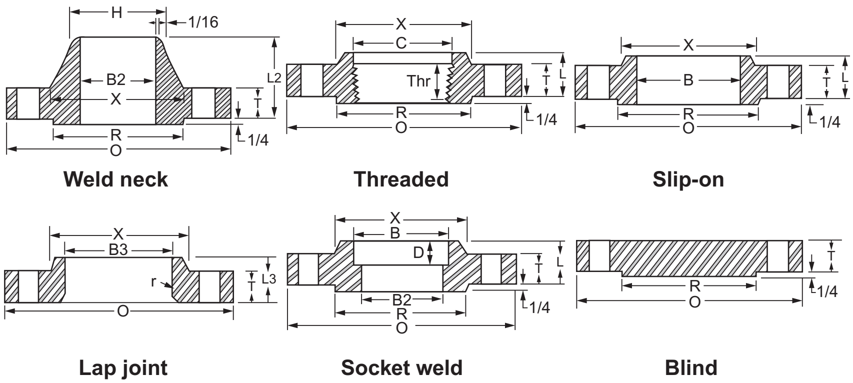
Nom. pipe size	O	T_1	R	X	No.2 & dia. of holes	Bolt circle dia.	$L2_1$	H	$B2_3$	L	B	r	$L3_4$	B3	D	C	Thr
½	3.75	0.56	1.38	1.5	4-0.62	2.62	2.06	0.84	0.62	0.88	0.88	0.12	0.88	0.9	0.38	0.93	0.62
¾	4.62	0.62	1.69	1.88	4-0.75	3.25	2.25	1.05	0.82	1	1.09	0.12	1	1.11	0.44	1.14	0.62
1	4.88	0.69	2	2.12	4-0.75	3.5	2.44	1.32	1.05	1.06	1.36	0.12	1.06	1.38	0.5	1.41	0.69
1¼	5.25	0.75	2.5	2.5	4-0.75	3.88	2.56	1.66	1.38	1.06	1.7	0.19	1.06	1.72	0.56	1.75	0.81
1½	6.12	0.81	2.88	2.75	4-0.88	4.5	2.69	1.9	1.61	1.19	1.95	0.25	1.19	1.97	0.62	1.99	0.88
2	6.5	0.88	3.62	3.31	8-0.75	5	2.75	2.38	2.07	1.31	2.44	0.31	1.31	2.46	0.69	2.5	1.12
2½	7.5	1	4.12	3.94	8-0.88	5.88	3	2.88	2.47	1.5	2.94	0.31	1.5	2.97	0.75	3	1.25
3	8.25	1.12	5	4.62	8-0.88	6.62	3.12	3.5	3.07	1.69	3.57	0.38	1.69	3.6	0.81	3.63	1.25
3½	9	1.19	5.5	5.25	8-0.88	7.25	3.19	4	3.55	1.75	4.07	0.38	1.75	4.1		4.13	1.44
4	10	1.25	6.19	5.75	8-0.88	7.88	3.38	4.5	4.03	1.88	4.57	0.44	1.88	4.6		4.63	1.44
5	11	1.38	7.31	7	8-0.88	9.25	3.88	5.56	5.05	2	5.66	0.44	2	5.69		5.69	1.69
6	12.5	1.44	8.5	8.12	12-0.88	10.62	3.88	6.63	6.07	2.06	6.72	0.5	2.06	6.75		6.75	1.81
8	15	1.62	10.62	10.25	12-1.00	13	4.38	8.63	7.98	2.44	8.72	0.5	2.44	8.75		8.75	2
10	17.5	1.88	12.75	12.62	16-1.12	15.25	4.62	10.75	10.02	2.62	10.88	0.5	3.75	10.92		10.88	2.19
12	20.5	2	15	14.75	16-1.25	17.25	5.12	12.75	12.00	2.88	12.88	0.5	4	12.92		12.94	2.38
14	23	2.12	16.25	16.75	20-1.25	20.25	5.62	14	13.25	3	14.14	0.5	4.38	14.18		14.19	2.5
16	25.5	2.25	18.5	19	20-1.38	22.5	5.75	16	15.25	3.25	16.16	0.5	4.75	16.19		16.19	2.69
18	28	2.38	21	21	24-1.38	24.75	6.25	18	17.25	3.5	18.18	0.5	5.12	18.2		18.19	2.75
20	30.5	2.5	23	23.12	24-1.38	27	6.38	20	19.25	3.75	20.2	0.5	5.5	20.25		20.19	2.88
22	33	2.63	25.25	25.25	24-1.63	29.25	6.5	22	21.25	4.00	22.22	0.5	5.75	22.25		22.19	3.13
24	36	2.75	27.25	27.62	24-1.62	32	6.62	24	23.25	4.19	24.25	0.5	6	24.25		24.19	3.25

ANSI B16.5 Class 400 Forged Flanges



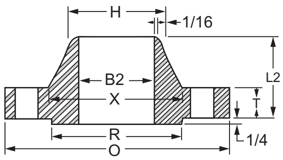
Nom. pipe size	O	T_1	R	X	No.2 & dia. of holes	Bolt circle dia.	$L2_1$	H	B2	L	B	r	L3	B3	D	C	Thr
½	3.75	0.56	1.38	1.5	4-0.62	2.62	2.06	0.84	Specified by purchaser	0.88	0.88	0.12	0.88	0.9	0.38	0.93	0.62
¾	4.62	0.62	1.69	1.88	4-0.75	3.25	2.25	1.05		1	1.09	0.12	1	1.11	0.44	1.14	0.62
1	4.88	0.69	2	2.12	4-0.75	3.5	2.44	1.32		1.06	1.36	0.12	1.06	1.38	0.5	1.41	0.69
1¼	5.25	0.81	2.5	2.5	4-0.75	3.88	2.62	1.66		1.12	1.7	0.19	1.12	1.72	0.56	1.75	0.81
1½	6.12	0.88	2.88	2.75	4-0.88	4.5	2.75	1.9		1.25	1.95	0.25	1.25	1.97	0.62	1.99	0.88
2	6.5	1	3.62	3.31	8-0.75	5	2.88	2.38		1.44	2.44	0.31	1.44	2.46	0.69	2.5	1.12
2½	7.5	1.12	4.12	3.94	8-0.88	5.88	3.12	2.88		1.62	2.94	0.31	1.62	2.97	0.75	3	1.25
3	8.25	1.25	5	4.62	8-0.88	6.62	3.25	3.5		1.81	3.57	0.38	1.81	3.6	0.81	3.63	1.38
3½	9	1.38	5.5	5.25	8-1.00	7.25	3.38	4		1.94	4.07	0.38	1.94	4.1		4.13	1.56
4	10	1.38	6.19	5.75	8-1.00	7.88	3.5	4.5		2	4.57	0.44	2	4.6		4.63	1.44
5	11	1.5	7.31	7	8-1.00	9.25	4	5.56		2.12	5.66	0.44	2.12	5.69		5.69	1.69
6	12.5	1.62	8.5	8.12	12-1.00	10.62	4.06	6.63		2.25	6.72	0.5	2.25	6.75		6.75	1.81
8	15	1.88	10.62	10.25	12-1.12	13	4.62	8.63		2.69	8.72	0.5	2.69	8.75		8.75	2
10	17.5	2.12	12.75	12.62	16-1.25	15.25	4.88	10.75		2.88	10.88	0.5	4	10.92		10.88	2.19
12	20.5	2.25	15	14.75	16-1.38	17.25	5.38	12.75		3.12	12.88	0.5	4.25	12.92		12.94	2.38
14	23	2.38	16.25	16.75	20-1.38	20.25	5.88	14		3.31	14.14	0.5	4.62	14.18		14.19	2.5
16	25.5	2.5	18.5	19	20-1.50	22.5	6	16		3.69	16.16	0.5	5	16.19		16.19	2.69
18	28	2.62	21	21	24-1.50	24.75	6.5	18		3.88	18.18	0.5	5.38	18.2		18.19	2.75
20	30.5	2.75	23	23.12	24-1.62	27	6.62	20		4	20.2	0.5	5.75	20.25		20.19	2.88
22	33	2.88	25.25	25.25	24-1.75	29.25	6.75	22		4.25	22.22	0.5	6	22.25		--	--
24	36	3	27.25	27.62	24-1.88	32	6.88	24		4.5	24.25	0.5	6.25	24.25		24.19	3.25

ANSI B16.5 Class 600 Forged Flanges

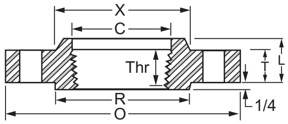


Nom. pipe size	O	T_1	R	X	No.2 and dia. of bolt holes	Bolt circle dia.	$L2_1$	H	B2	L	B	r	L3	B3	D	C	Thr
½	3.75	0.56	1.38	1.5	4-0.62	2.62	2.06	0.84	To be Specified by purchaser	0.88	0.88	0.12	0.88	0.9	0.38	0.93	0.62
¾	4.62	0.62	1.69	1.88	4-0.75	3.25	2.25	1.05		1	1.09	0.12	1	1.11	0.44	1.14	0.62
1	4.88	0.69	2	2.12	4-0.75	3.5	2.44	1.32		1.06	1.36	0.12	1.06	1.38	0.5	1.41	0.69
1¼	5.25	0.81	2.5	2.5	4-0.75	3.88	2.62	1.66		1.12	1.7	0.19	1.12	1.72	0.56	1.75	0.81
1½	6.12	0.88	2.88	2.75	4-0.88	4.5	2.75	1.9		1.25	1.95	0.25	1.25	1.97	0.62	1.99	0.88
2	6.5	1	3.62	3.31	8-0.75	5	2.88	2.38		1.44	2.44	0.31	1.44	2.46	0.69	2.5	1.12
2½	7.5	1.12	4.12	3.94	8-0.88	5.88	3.12	2.88		1.62	2.94	0.31	1.62	2.97	0.75	3	1.25
3	8.25	1.25	5	4.62	8-0.88	6.62	3.25	3.5		1.81	3.57	0.38	1.81	3.6	0.81	3.63	1.38
3½	9	1.38	5.5	5.25	8-1.00	7.25	3.38	4		1.94	4.07	0.38	1.94	4.1		4.13	1.56
4	10.75	1.5	6.19	6	8-1.00	8.5	4	4.5		2.12	4.57	0.44	2.12	4.6		4.63	1.62
5	13	1.75	7.31	7.44	8-1.12	10.5	4.5	5.56		2.38	5.66	0.44	2.38	5.69		5.69	1.88
6	14	1.88	8.5	8.75	12-1.12	11.5	4.62	6.63		2.62	6.72	0.5	2.62	6.75		6.75	2
8	16.5	2.19	10.62	10.75	12-1.25	13.75	5.25	8.63		3	8.72	0.5	3	8.75		8.75	2.25
10	20	2.50	12.75	13.5	16-1.38	17	6	10.75		3.38	10.88	0.5	4.38	10.92		10.88	2.56
12	22	2.62	15	15.75	20-1.38	19.25	6.12	12.75		3.62	12.88	0.5	4.62	12.92		12.94	2.75
14	23.75	2.75	16.25	17	20-1.50	20.75	6.5	14		3.69	14.14	0.5	5	14.18		14.19	2.88
16	27	3.00	18.5	19.5	20-1.62	23.75	7	16		4.19	16.16	0.5	5.5	16.19		18.19	3.06
18	29.25	3.25	21	21.5	20-1.75	25.75	7.25	18		4.62	18.18	0.5	6	18.2		18.1	3.12
20	32	3.5	23	24	24-1.75	28.5	7.5	20		5	20.2	0.5	6.5	20.25		20.19	3.25
22	34.25	3.75	25.25	26.25	24-1.75	30.63	7.75	22		5.25	22.22	0.5	6.88	22.25		--	--
24	37	4	27.25	28.25	24-2.00	33	8	24		5.5	24.25	0.5	7.25	24.25		24.19	3.62

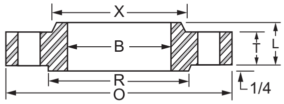
ANSI B16.5 Class 900 Forged Flanges



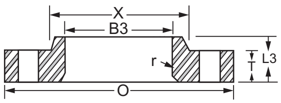
Weld neck



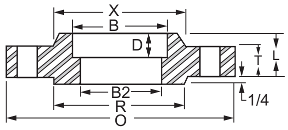
Threaded



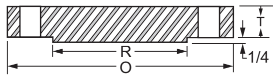
Slip-on



Lap joint



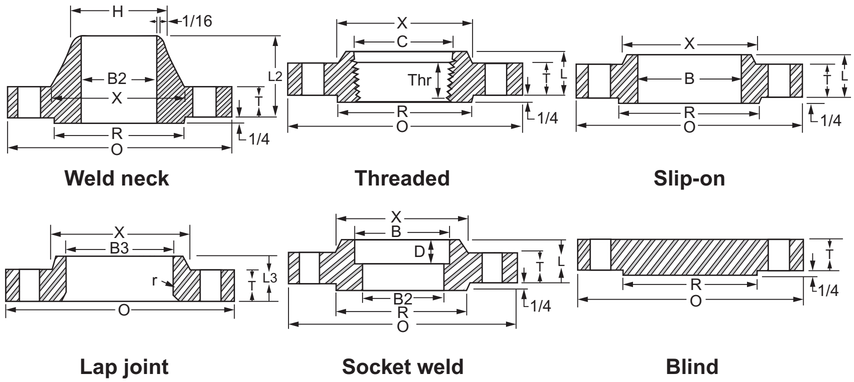
Socket weld



Blind

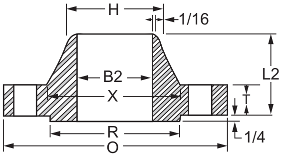
Nom. pipe size	O	T_1	R	X	No.2 and dia. of bolt holes	Bolt circle dia.	$L2_1$	H	B2	L	B	r	L3	B3	Thr
Sizes ½" thru 2½" are identical to class 1500															
3	9.50	1.50	5.00	5.00	8-1.00	7.50	4.00	3.5	Specified by purchaser	2.13	3.57	0.38	2.13	3.6	1.63
4	11.50	1.75	6.19	6.25	8-1.25	9.25	4.50	4.5		2.75	4.57	0.44	2.75	4.6	1.88
5	13.75	2.00	7.31	7.50	8-1.38	11.50	5.00	5.56		3.13	5.66	0.44	3.13	5.69	2.13
6	15.00	2.19	8.50	9.25	12-1.25	12.50	5.50	6.63		3.38	6.72	0.5	3.38	6.75	2.25
8	18.50	2.50	10.63	11.75	12-1.50	15.50	6.38	8.63		4.00	8.72	0.5	4.50	8.75	2.50
10	21.50	2.75	12.75	14.50	16-1-50	18.50	7.25	10.75		4.25	10.88	0.5	5.00	10.92	2.81
12	24.00	3.13	15.00	16.50	20-1-50	21.00	7.88	12.75		4.63	12.88	0.5	5.63	12.92	3.00
14	25.25	3.38	16.25	17.75	20-1-63	22.00	8.38	14		5.13	14.14	0.5	6.13	14.18	3.25
16	25.75	3.50	18.50	20.00	20-1.75	24.25	8.50	16		5.25	16.16	0.5	6.50	16.19	3.38
18	31.00	4.00	21.00	22.25	20-2.00	27.00	9.00	18		6.00	18.18	0.5	7.50	18.2	3.50
20	33.75	4.25	23.00	24.50	20-2.13	29.50	9.75	20		6.25	20.2	0.5	8.25	20.25	3.63
24	41.00	5.50	27.25	29.50	20-2.63	35.50	11.50	24		8.00	24.25	0.5	10.5	24.25	4.00

ANSI B16.5 Class 1500 Forged Flanges

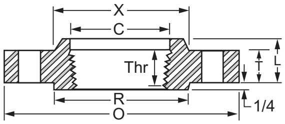


Nom. pipe size	O	T_1	R	X	No.2 and dia. of bolt holes	Bolt circle dia.	$L2_1$	H	B2	L	B	r	L3	D	B3	Thr
½"	4.75	0.88	1.38	1.50	4-0.88	3.25	2.38	0.84	Specified by purchaser	1.25	0.88	0.13	1.25	0.38	0.90	0.88
¾	5.13	1.00	1.69	1.75	4-0.88	3.50	2.75	1.05		1.38	1.09	0.13	1.38	0.44	1.11	1.00
1	5.88	1.13	2.00	2.06	4-1.00	4.00	2.88	1.32		1.63	1.36	0.13	1.63	0.50	1.38	1.13
1¼	6.25	1.13	2.50	2.50	4-1.00	4.38	2.88	1.66		1.63	1.70	0.19	1.63	0.56	1.72	1.19
1½	7.00	1.25	2.88	2.75	4-1.13	4.88	3.25	1.90		1.75	1.95	0.25	1.75	0.63	1.97	1.25
2	8.50	1.50	3.63	4.13	8-1.00	6.50	4.00	2.38		2.25	2.44	0.31	2.25	0.69	2.46	1.50
2½	9.63	1.63	4.13	4.88	8-1.13	7.50	4.13	2.88		2.50	2.94	0.31	2.50	0.75	2.97	1.88
3	10.50	1.88	5.00	5.25	8-1.25	8.00	4.63	3.50		2.88	3.57	0.38	2.88	-	3.60	2.00
4	12.25	2.13	6.19	6.38	8-1.38	9.50	4.88	4.50		3.56	4.57	0.44	3.56	-	4.60	2.25
5	14.75	2.88	7.31	7.75	8-1.63	11.50	6.13	5.56		4.13	5.66	0.44	4.13	-	5.69	2.50
6	15.50	3.25	8.50	9.00	12-1.50	12.50	6.75	6.63		4.69	6.72	0.50	4.69	-	6.75	2.75
8	19.00	3.63	10.63	11.50	12-1.75	15.50	8.38	8.63		5.63	8.72	0.50	5.63	-	8.75	3.00
10	23.00	4.25	12.75	14.50	12-2.00	19.00	10.00	10.75		6.25	10.88	0.50	7.00	-	10.92	3.31
12	26.50	4.88	15.00	17.75	16-2.13	22.50	11.13	12.75		7.13	12.88	0.50	8.63	-	12.92	3.63
14	29.50	5.25	16.25	19.50	16-2.38	25.00	11.75	14.00		-	-	0.50	9.50	-	14.18	-
16	32.50	5.75	18.50	21.75	16-2.63	27.75	12.25	16.00		-	-	0.50	10.25	-	16.19	-
18	36.00	6.38	21.00	23.50	16-2.88	30.50	12.88	18.00		-	-	0.50	10.88	-	18.20	-
20	38.75	7.00	23.00	25.25	16-3.13	32.75	14.00	20.00		-	-	0.50	11.50	-	20.25	-
24	46.00	8.00	27.25	30.00	16-3.63	39.00	16.00	24.00		-	-	0.50	13.00	-	24.25	-

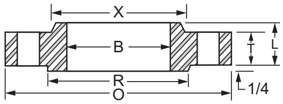
ANSI B16.5 Class 2500 Forged Flanges



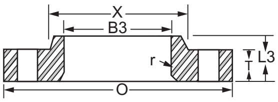
Weld neck



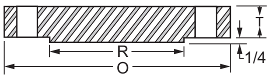
Threaded



Slip-on



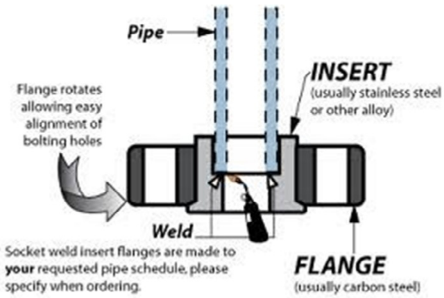
Lap joint



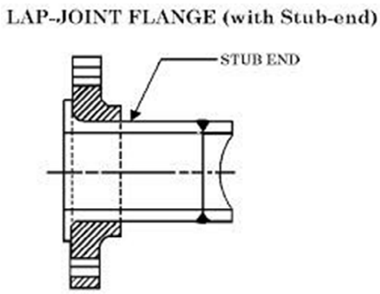
Blind

Nom. pipe size	O	T_1	R	X	No.2 and dia. of bolt holes	Bolt circle dia.	$L2_1$	H	B2	L	B	r	L3	B3	Thr
½"	5.25	1.19	1.38	1.69	4-0.88	3.50	2.88	0.84	Specified by purchaser	1.56	0.88	0.13	1.56	0.90	1.13
¾	5.50	1.25	1.69	2.00	4-0.88	3.75	3.13	1.05		1.69	1.09	0.13	1.69	1.11	1.25
1	6.25	1.38	2.00	2.25	4-1.00	4.25	3.50	1.32		1.88	1.36	0.13	1.88	1.38	1.38
1¼	7.25	1.50	2.50	2.88	4-1.13	5.13	3.75	1.66		2.06	1.70	0.18	2.06	1.72	1.50
1½	8.00	1.75	2.88	3.13	4-1.25	5.75	4.38	1.90		2.38	1.95	0.25	2.38	1.97	1.75
2	9.25	2.00	3.63	3.75	8-1.13	6.75	5.00	2.38		2.75	2.44	0.31	2.75	2.46	2.00
2½	10.50	2.25	4.13	4.50	8-1.25	7.75	5.63	2.88		3.13	2.94	0.31	3.13	2.97	2.25
3	12.00	2.63	5.00	5.25	8-1.38	9.00	6.63	3.50		3.63	3.57	0.37	3.63	3.60	2.50
4	14.00	3.00	6.19	6.50	8-1.63	10.75	7.50	4.50		4.25	4.57	0.44	4.25	4.60	2.75
5	16.50	3.63	7.31	8.00	8-1.88	12.75	9.00	5.56		5.13	5.66	0.44	5.13	5.69	3.00
6	19.00	4.25	8.50	9.25	8-2.13	14.50	10.75	6.63		6.00	6.72	0.50	6.00	6.75	3.25
8	21.75	5.00	10.63	12.00	12-2.13	17.25	12.50	8.63		7.00	8.72	0.50	7.00	8.75	3.75
10	26.50	6.50	12.75	14.75	12-2.63	21.25	16.50	10.75		9.00	10.88	0.50	9.00	10.92	4.25
12	30.00	7.25	15.00	17.38	16-2.88	24.38	18.25	12.75		10.00	12.88	0.50	10.00	12.92	4.75

Standard flange picture



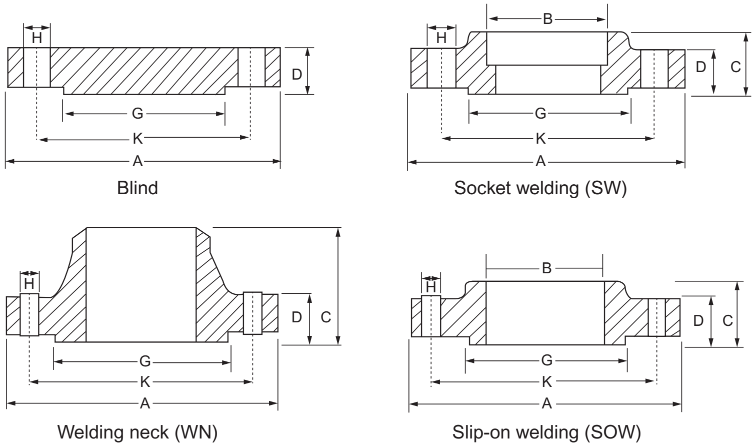
Socket weld flange



Lap joint flange

Service	Flange Design Conditions			
	Pressure Class	Temp. (°C)	Flange Facing	Gasket Selection
General hydrocarbon	150	−196/500*	RF	Tanged graphite sheet or
	300			
Steam/condensate, boiler feed water		−196/+500		Spiral wound with flexible graphite or
		−196/350		Spiral wound with nongraphite filter
General utilities		−40/+250	RF	Nitrile rubber based reinforced sheet
General hydrocarbon, steam/condensate, boiler feed water	6oo	−196/+500	RF	Spiral wound with flexible graphite
	900			
General hydrocarbon, steam, boiler feed water	1500	As per flange material	RTJ	Metal joint ring
	2500			
Hydrogen	150	−196/+500	RF	Spiral wound with flexible graphite
	300			
	600			
	900	As per flange material	RTJ	Metal joint ring
	1500			
	2500			
Chemical oxidizers/ HF acid	150	−40/+200	RF	PTFE (reinforced or envelope)
	150	−40/+200	RF	Spiral wound PTFE filler
	300			
	600			

Flange weights



Note 1: All weights are approximate

Note 2: For Class 150, 300 the flange thickness "D" dimension includes approx. 1.5mm for the raised face height
For Class 600, 900, 1500, 2500 the flange thickness does not include the raised face height and approx. 6.4mm must be added to D dimension

Note 3: Bolt length dimensions incorporate the height of the raised face

Note 4: Welding neck bore is devived from the pipe schedule

Class 150 flanges to ASME B16.5

Nominal size		Dimensions												Weight (kg)		
						Length thru hub		Bolt drilling								
DN	NPS	Flange OD A mm	Flange thickness D mm	Bore SOW SW B mm	Raised face diam. G mm	SOW, SW threaded C mm	W neck C mm	Circle diam. K mm	Hole diam. H mm	Bolts No.	Bolt diam. in	RF stud bolt length mm	RF mach. bolt length mm	SOW SW	WN	Blind
15	½	88.9	11.2	22.4	35.1	15.8	47.8	60.4	15.7	4	½"	60.0	45.0	0.4	0.5	0.4
20	¾	98.6	12.7	27.7	42.9	15.8	52.3	69.9	15.7	4	½"	65.0	50.0	0.6	0.7	0.6
25	1	108.0	14.2	34.5	50.8	17.5	55.6	79.2	15.7	4	½"	65.0	55.0	0.8	1.0	0.9
32	1¼	117.3	15.7	43.2	63.5	20.6	57.2	88.9	15.7	4	½"	70.0	55.0	1.0	1.3	1.2
40	1½	127.0	17.5	49.5	73.2	22.4	62.0	98.6	15.7	4	½"	70.0	60.0	1.3	1.7	1.5
50	2	152.4	19.1	62.0	91.9	25.5	63.5	120.7	19.1	4	⅝"	80.0	65.0	2.1	2.6	2.4
65	2½	177.8	22.4	74.7	104.6	28.5	69.9	139.7	19.1	4	⅝"	90.0	75.0	3.3	4.1	3.9
80	3	190.5	23.9	90.7	127.0	30.2	69.9	152.4	19.1	4	⅝"	90.0	75.0	3.9	4.9	4.9
90	3½	215.9	23.9	103.4	139.7	31.8	71.4	177.8	19.1	8	⅝"	90.0	75.0	4.8	6.1	6.2
100	4	228.6	23.9	116.1	157.2	33.3	76.2	190.5	19.1	8	⅝"	90.0	75.0	5.3	6.8	7.0
125	5	254.0	23.9	143.8	185.7	36.6	88.9	215.9	22.4	8	¾"	90.0	80.0	6.1	8.6	8.6
150	6	279.4	25.4	170.7	215.9	39.6	88.9	241.3	22.4	8	¾"	100.0	85.0	7.5	10.6	11.3
200	8	342.9	28.4	221.5	269.7	44.5	101.6	298.5	22.4	8	¾"	110.0	90.0	12.1	17.6	19.6
250	10	406.4	30.2	276.4	323.9	49.3	101.6	362.0	25.4	12	⅞"	115.0	95.0	16.5	24.0	28.8
300	12	482.6	31.8	327.2	381.0	55.6	114.3	431.8	25.4	12	⅞"	120.0	100.0	26.2	36.5	43.2
350	14	533.4	35.1	359.2	412.8	57.2	127.0	476.3	28.4	12	1"	130.0	110.0	34.6	48.4	58.1
400	16	596.9	36.6	410.5	469.9	63.5	127.0	539.8	28.4	16	1"	135.0	115.0	44.8	60.6	76.1
450	18	635.0	39.6	461.8	533.4	68.3	139.7	577.9	31.8	16	1⅛"	150.0	125.0	48.9	68.3	93.7
500	20	698.5	42.9	513.1	584.2	73.2	144.5	635.0	31.8	20	1⅛"	160.0	135.0	61.9	84.5	122.0
600	24	812.8	47.8	616.0	692.2	82.6	152.4	479.3	35.1	20	1¼"	175.0	145.0	86.9	115.0	185.0

Class 300 flanges to ASME B16.5																
Nominal size		Dimensions												Weight (kg)		
						Length thru hub		Bolt drilling								
DN	NPS	Flange OD A mm	Flange thickness D mm	Bore SOW SW B mm	Ralsed face diam. G mm	SOW, SW threaded C mm	W neck C mm	Circle diam. K mm	Hole diam. H mm	Bolts No.	Bolt diam. in	RF stud bolt length mm	RF mach. bolt length mm	SOW SW	WN	Blind
15	½	95.3	14.2	22.4	35.1	22.4	52.3	66.5	15.7	4	½"	65.0	55.0	0.6	0.8	0.6
20	¾	117.3	15.2	27.7	42.9	25.4	57.2	82.6	19.1	4	⅝"	75.0	60.0	1.1	1.3	1.1
25	1	124.0	17.5	34.5	50.8	26.9	62.0	88.9	19.1	4	⅝"	80.0	65.0	1.4	1.5	1.4
32	1¼	133.4	19.1	43.2	63.5	26.9	65.0	98.6	19.1	4	⅝"	80.0	65.0	1.7	2.0	1.8
40	1½	155.5	20.6	49.5	73.2	30.2	68.3	114.3	22.4	4	¾"	90.0	75.0	2.5	2.9	2.7
50	2	165.1	22.4	62.0	91.9	33.3	69.9	127.0	19.1	8	⅝"	90.0	75.0	2.9	3.4	3.2
65	2½	190.5	25.4	74.7	104.6	38.1	76.2	149.4	22.4	8	¾"	100.0	85.0	4.3	5.2	4.9
80	3	215.9	28.4	90.7	127.0	42.9	79.2	168.1	22.4	8	¾"	110.0	90.0	5.9	6.9	6.8
90	3½	228.6	30.2	103.4	139.7	44.5	81.0	184.2	22.4	8	¾"	110.0	95.0	7.3	8.7	8.7
100	4	254.0	31.8	116.1	157.2	47.8	85.9	200.2	22.4	8	¾"	110.0	95.0	9.6	11.2	11.5
125	5	279.4	35.1	143.8	185.7	50.8	98.6	235.0	22.4	8	¾"	120.0	100.0	12.3	15.1	15.6
150	6	317.5	36.6	170.7	215.9	52.3	98.6	269.7	22.4	12	¾"	125.0	105.0	15.6	19.1	20.9
200	8	381.0	41.1	221.5	269.7	62.0	112.3	330.2	25.4	12	⅞"	140.0	110.0	24.2	29.9	34.3
250	10	444.5	47.6	276.4	323.9	66.5	117.3	387.4	28.4	16	1"	155.0	130.0	34.1	42.7	53.3
300	12	520.7	50.8	327.2	381.0	73.2	130.0	450.9	31.8	16	1⅛"	170.0	145.0	49.8	61.8	78.8
350	14	584.2	53.8	359.2	412.8	76.2	142.7	514.4	31.8	20	1⅛"	175.0	150.0	69.9	85.8	105.0
400	16	647.7	57.2	410.5	469.9	82.6	146.1	571.5	35.1	20	1¼"	190.0	160.0	88.1	106.0	137.0
450	18	711.2	60.5	461.8	533.4	88.9	158.8	626.7	35.1	24	1¼"	195.0	170.0	109.0	131.0	175.0
500	20	774.7	63.5	513.1	584.2	95.3	162.1	685.8	35.1	24	1¼"	205.0	180.0	134.0	158.0	221.0
600	24	914.4	70.0	616.0	692.2	106.4	106.4	812.8	41.1	24	1½"	230.0	195.0	201.0	230.0	339.0

Class 600 flanges to ASME B16.5															
Nominal size		Dimensions											Weight (kg)		
						Length thru hub		Bolt drilling							
DN	NPS	Flange OD A mm	Flange thickness D mm	Bore SOW SW B mm	Ralsed face diam. G mm	SOW, SW threaded C mm	W neck C mm	Circle diam. K mm	Hole diam. H mm	Bolts No.	Bolt diam. in	RF stud bolt length mm	SOW SW	WN	Blind
15	½	95.3	14.2	22.4	35.1	22.4	52.3	66.5	15.7	4	½"	80.0	0.7	0.9	0.8
20	¾	117.3	15.7	27.7	42.9	25.4	57.2	82.6	19.1	4	⅝"	90.0	1.3	1.5	1.3
25	1	124.0	17.5	34.5	50.8	26.9	62.0	88.9	19.1	4	⅝"	90.0	1.5	1.8	1.6
32	1¼	133.4	20.6	43.2	63.5	28.4	66.5	98.6	19.1	4	⅝"	100.0	2.0	2.5	2.2
40	1½	155.4	22.4	49.5	73.2	31.8	69.9	114.3	22.4	4	¾"	105.0	3.0	3.5	3.3
50	2	165.1	25.4	62.0	91.9	36.6	73.2	127.0	19.1	8	⅝"	105.0	3.6	4.4	4.2
65	2½	190.5	28.4	74.7	104.6	41.1	79.2	149.4	22.4	8	¾"	120.0	5.3	6.4	6.1
80	3	209.6	31.8	90.7	127.0	46.0	82.6	168.1	22.4	8	¾"	125.0	7.0	8.5	8.4
90	3½	228.6	35.1	103.4	139.7	49.3	85.9	184.2	25.4	8	⅞"	140.0	8.8	10.7	11.0
100	4	273.1	38.1	116.1	157.2	53.8	101.6	215.9	25.4	8	⅞"	145.0	14.5	17.4	17.3
125	5	330.2	44.5	143.8	185.7	60.5	114.3	266.7	28.4	8	1"	165.0	24.4	29.2	29.4
150	6	355.6	47.8	170.7	215.9	66.5	117.3	292.1	28.4	12	1"	170.0	28.7	34.9	36.1
200	8	419.1	55.6	221.5	269.7	76.2	133.4	349.3	31.8	12	1⅛"	195.0	43.4	53.9	58.9
250	10	508.0	63.5	276.4	323.9	85.9	152.4	431.8	35.1	16	1¼"	215.0	70.3	86.5	97.5
300	12	558.8	66.5	327.2	381.0	91.9	155.4	489.0	35.1	20	1¼"	220.0	84.2	103.0	124.0
350	14	603.3	69.9	359.2	412.8	93.7	165.1	527.1	38.1	20	1⅜"	235.0	98.7	122.0	151.0
400	16	685.8	76.2	410.5	469.9	106.4	177.8	603.3	41.1	20	1½"	255.0	142.0	170.0	214.0
450	18	743.0	82.6	461.8	533.4	117.3	184.2	654.1	44.5	24	1⅝"	275.0	173.0	204.0	272.0
500	20	812.8	88.9	513.1	584.2	127.0	190.5	723.9	44.5	24	1⅝"	290.0	220.0	254.0	349.0
600	24	939.8	101.6	616.0	692.2	139.7	203.2	838.2	50.8	24	1⅞"	330.0	312.0	358.0	533.0

Class 900 flanges to ASME B16.5

Nominal size		Dimensions											Weight (kg)		
						Length thru hub		Bolt drilling							
DN	NPS	Flange OD A mm	Flange thickness D mm	Bore SOW SW B mm	Ralsed face diam. G mm	SOW, SW threaded C mm	W neck C mm	Circle diam. K mm	Hole diam. H mm	Bolts No.	Bolt diam. in	RF stud bolt length mm	SOW SW	WN	Blind
15	½	120.7	22.4	22.4	35.1	31.8	60.5	82.6	22.4	4	¾"	105.0	1.8	1.9	1.8
20	¾	130.0	25.4	27.7	42.9	35.1	70.0	88.9	22.4	4	¾"	115.0	2.4	2.6	2.4
25	1	149.4	28.4	34.5	50.8	41.1	73.2	101.6	25.4	4	⅞"	125.0	3.6	3.7	3.6
32	1¼	158.8	28.4	43.2	63.5	41.1	73.2	111.3	25.4	4	⅞"	125.0	4.0	4.3	4.1
40	1½	177.8	31.8	49.5	73.2	44.5	82.6	124.0	28.4	4	1"	140.0	5.5	5.9	5.8
50	2	215.9	38.1	62.0	91.9	57.2	101.6	165.1	25.4	8	⅞"	145.0	10.2	10.8	10.1
65	2½	244.3	41.1	74.7	104.6	63.5	104.6	190.5	28.4	8	1"	160.0	13.9	15.0	14.0
80	3	241.3	38.1	90.7	127.0	53.8	101.6	190.5	25.4	8	⅞"	145.0	11.6	13.7	13.1
100	4	292.1	44.5	116.1	157.2	69.9	114.3	235.0	31.8	8	1⅛"	170.0	19.7	22.5	26.9
125	5	349.3	50.8	143.8	185.7	79.2	127.0	279.4	35.1	8	1¼"	190.0	31.9	37.4	36.5
150	6	381.0	55.6	170.7	215.9	85.9	139.7	317.5	31.8	12	1⅛"	195.0	41.1	47.7	47.4
200	8	469.9	63.5	221.5	269.7	101.6	162.1	393.7	38.1	12	1⅜"	220.0	70.7	81.3	82.5
250	10	546.1	69.9	276.4	323.9	108.0	184.2	469.9	38.1	16	1⅜"	235.0	101.0	119.0	122.0
300	12	609.6	79.2	327.2	381.0	117.3	200.2	533.4	38.1	20	1⅜"	255.0	133.0	157.0	173.0
350	14	641.4	85.6	359.2	412.8	130.0	212.9	558.8	41.1	20	1½"	275.0	153.0	180.0	206.0
400	16	704.9	88.9	410.5	469.9	133.4	215.9	616.0	44.5	20	1⅝"	285.0	185.0	217.0	259.0
450	18	787.4	101.6	461.8	533.4	152.4	228.6	685.8	50.8	20	1⅞"	325.0	258.0	292.0	367.0
500	20	857.3	108.0	513.1	584.2	158.8	247.7	749.3	53.8	20	2"	345.0	317.0	362.0	469.0
600	24	1041.4	139.7	616.0	692.2	203.2	292.1	901.7	66.5	20	2½"	435.0	606.0	665.0	876.0

Class 1500 flanges to ASME B16.5

Nominal size		Dimensions											Weight (kg)		
						Length thru hub		Bolt drilling							
DN	NPS	Flange OD A mm	Flange thickness D mm	Bore SOW SW B mm	Ralsed face diam. G mm	SOW, SW threaded C mm	W neck C mm	Circle diam. K mm	Hole diam. H mm	Bolts No.	Bolt diam. in	RF stud bolt length mm	SOW SW	WN	Blind
15	½	120.7	22.4	22.4	35.1	31.8	60.5	82.6	22.4	4	¾"	105.0	1.8	1.9	1.8
20	¾	130.0	25.4	27.7	42.9	35.1	69.9	88.9	22.4	4	¾"	115.0	2.4	2.6	2.4
25	1	149.4	28.4	34.5	50.8	41.1	73.2	101.6	25.4	4	⅞"	125.0	3.6	3.7	3.6
32	1¼	158.8	28.4	43.2	63.5	41.1	73.2	111.3	25.4	4	⅞"	125.0	4.0	4.3	4.1
40	1½	177.8	31.8	49.5	73.2	44.5	82.6	124.0	28.4	4	1"	140.0	5.5	5.9	5.8
50	2	215.9	38.1	62.0	91.9	57.2	101.6	165.1	25.4	8	⅞"	145.0	10.2	10.8	10.1
65	2½	244.3	41.1	74.7	104.6	63.5	104.6	190.5	28.4	8	1"	160.0	13.9	15.0	14.0
80	3	266.7	47.8	90.7	127.0		117.3	203.2	31.8	8	1⅛"	180.0		19.9	19.1
100	4	311.2	53.8	116.1	157.2		124.0	241.3	35.1	8	1¼"	195.0		29.9	29.9
125	5	374.7	73.2	143.8	185.7		155.4	292.1	41.1	8	1½"	250.0		55.4	58.4
150	6	393.7	82.6	170.7	215.9		171.5	317.5	38.1	12	1⅜"	260.0		68.4	71.8
200	8	482.6	91.9	221.5	269.7		212.9	393.7	44.5	12	1⅝"	290.0		117.0	122.0
250	10	584.2	108.0	276.4	323.9		254.0	482.6	50.8	12	1⅞"	335.0		194.0	210.0
300	12	673.1	124.0	327.2	381.0		282.4	571.5	53.8	16	2"	375.0		288.0	316.0
350	14	749.3	133.4	359.2	412.8		298.5	635.0	60.4	16	2¼"	405.0		380.0	420.0
400	16	825.5	146.1	410.5	469.9		311.2	704.9	66.5	16	2½"	445.0		485.0	558.0
450	18	914.4	162.1	461.8	533.4		327.2	774.7	73.2	16	2¾"	495.0		644.0	760.0
500	20	984.3	177.8	513.1	584.2		355.6	831.9	79.2	16	3.0	540.0		775.0	965.0
600	24	1168.4	203.2	616.0	692.2		406.4	990.6	91.9	16	3½"	615.0		1232.0	1558.0

Class 2500 flanges to ASME B16.5													
Nominal size		Dimensions										Weight (kg)	
					Length thru hub		Bolt drilling						
DN	NPS	Flange OD A mm	Flange thickness D mm	Ralsed face diam. G mm	SOW, SW threaded C mm	W neck C mm	Circle diam. K mm	Hole diam. H mm	Bolts No.	Bolt diam. in	RF stud bolt length mm	WN	Blind
15	½	133.4	30.2	35.1	39.6	73.2	88.9	22.4	4	¾"	125.0	3.1	3.0
20	¾	139.7	31.8	42.9	42.9	79.2	95.3	22.4	4	¾"	125.0	3.7	3.5
25	1	158.8	35.1	50.8	47.8	88.9	108.0	25.4	4	⅞"	140.0	5.2	5.0
32	1¼	184.2	38.1	63.5	52.3	95.3	130.0	28.4	4	1"	150.0	7.7	7.4
40	1½	203.2	44.5	73.2	60.5	111.3	146.1	31.8	4	1⅛"	170.0	10.9	10.4
50	2	235.0	50.8	91.9	69.9	127.0	171.5	28.4	8	1"	175.0	16.2	15.6
65	2½	266.7	57.2	104.6	79.2	142.7	196.9	31.8	8	1⅛"	195.0	23.7	22.6
80	3	304.8	66.5	127.0		168.1	228.6	35.1	8	1¼"	220.0	36.2	34.8
100	4	355.6	76.2	157.2		190.5	273.1	41.1	8	1½"	255.0	55.3	53.9
125	5	419.1	91.9	185.7		228.6	323.9	47.8	8	1¾"	300.0	92.5	90.8
150	6	482.6	108.0	215.9		273.1	368.3	53.8	8	2"	345.0	143.0	141.0
200	8	552.5	127.0	269.7		317.5	438.2	53.8	12	2"	380.0	215.0	214.0
250	10	673.1	165.1	323.9		419.1	539.8	66.5	12	2½"	485.0	406.0	411.0
300	12	762.0	184.2	381.0		463.6	619.3	73.2	16	2¾"	540.0	572.0	592.0

Rating flanges

Rating, as applied to flanges, may best be defined as the maximum pressure allowed by the pressure piping code for the specific temperature at which the flange will be operating. Flanges and nozzles are sized according to pressure ratings established by the American National Standards Institute (ANSI).

These pressure ratings sometimes called *pound ratings* are divided into seven categories for forged steel flanges. They are 150#, 300#, 400#, 600#, 900#, 1500#, and 2500#. Cast iron flanges have pound ratings of 25#, 125#, 250#, and 800#. Pound ratings, when combined with the temperature of the commodity within the pipe are used to select the appropriate size, rating, and type of flange. This pressure/temperature relationship will allow any given flange to be used in a number of different applications.

For example, a 150# forged steel flange is rated to perform at 150# PSIG at 500°F. If the temperature were decreased to 100°F, this same flange could be used for 275# PSIG. However, if the temperature were increased to 750°F, the flange could only be used for 100# PSIG.

As you can see, the pressure/temperature relationship is important. When temperature decreases the allowable pressure increases, and vice versa. Pound ratings are also used to establish the outside diameter and thickness of a flange. Typically, as pound ratings increase, so will the flange's diameter and thickness.

Flange facings

The mating surface of a flange, nozzle, or valve is called the *face*. The face is usually machined to create a smooth surface. This smooth surface will help assure a leakproof seal when two flanges are bolted together with a gasket sandwiched in between.

Although numerous types of flange faces are produced, we will focus only on the following three:

- Flat face
- Raised face
- Ring-type joint

Flange types

Flanges have been designed and developed to be used in a myriad of applications. Each one has its own special characteristics, and should be carefully selected to meet specific function requirements. The following flanges are discussed:

- weld neck
- threaded
- socket weld
- slip-on
- lap-joint
- reducing
- blind
- orifice

Flat face

As the name implies, flanges with flat faces are those that have a flat, level connecting surface (as shown above).

Forged steel flanges with a flat face flange are commonly found in 150# and 300# ratings. Their principal use is to make connections with 125# and 250# cast iron flanges, respectively.

Attaching steel pipe to the cast iron flanges found on some valves and mechanical equipment always presents a problem because of the brittle nature of cast iron. Using a flat face flange will assure full surface contact, thereby reducing the possibility of cracking the softer cast iron.

Raised face

The most common face type in use, the raised face is available in all seven of the aforementioned pound ratings. Appropriately named, this flange face has a prominent raised surface. With shallow grooves etched into the raised surface, this flange face assures a positive grip with the gasket.

Flanges rated 150# and 300# have a 1/16″ raised face, flanges 400# and above have a 1/4″ raised face.

It is important to note most dimensioning charts, including the ones provided in this book, include the 1/16″ raised face thickness in the length dimensions for 150# and 300# flanges.

For 400# and higher pound ratings, the 1/4″ raised face thickness is *not* always included in the length dimensions. To assure accurate dimensioning, always determine if the dimensioning chart being used includes the 1/4″ raised face thickness for the larger pound rating flanges. The 1/4″ raised face thickness *must* be added to the dimensioning chart measurement to obtain the overall flange length if the dimensioning chart indicates it has not been added.

Weld neck flange

The **weld neck flange** is occasionally referred to as the "high-hub" flange. It is designed to reduce high-stress concentrations at the base of the flange by transferring stress to the adjoining pipe. Although expensive, the weld neck flange is the best-designed butt weld flange available because of its inherent structural value and ease of assembly.

Known for its strength and resistance to dishing, the weld neck flange is manufactured with a long tapered hub. The tapered hub is created by the gradual increase in metal thickness from the weld joint to the flange facing.

The symmetrical taper transition is extremely beneficial under conditions of repeated bending caused by line expansion, contraction, or other external forces.

Weld neck flanges are normally used in severe service applications involving high-pressures, high-temperatures, or subzero conditions.

Weld neck flanges are bored to match the ID of the adjoining pipe. In other words, the thinner the wall of the pipe, the larger the bore (hole) through the flange. The thicker the wall of the pipe, the smaller the bore. Because of these matching IDs, there is no restriction to the flow.

Turbulence and erosion are therefore eliminated.

Ring-type joint

Also known simply as *ring joint*, the ring-type joint does not use a gasket to form a seal between connecting flanges. Instead, a round metallic ring is used that rests in a deep groove cut into the flange face (as shown above).

The donut-shaped ring can be oval or octagonal in design. As the bolts are tightened, the metal ring is compressed, creating a tight seal.

Although it is the most expensive, the ring-type joint is considered to be the most efficient flange used in process piping systems.

The ring and groove design actually uses internal pressures to enhance the sealing capacity of the connecting flanges. The superiority of this seal can have its disadvantages, however. When dismantling ring joint connections, the flanges must be forcibly separated to release the ring from the groove. In crowded installations, this could cause major problems. Because of this, the ring joint flange is relegated to applications where space for maintenance and replacement are adequate.

Although available for all pound ratings, flanges with ring-type joint faces are normally used in piping systems rated 400# and higher.

Slip-on flange

The **slip-on flange** shown above has a low hub that allows the pipe to be inserted into the flange prior to welding. Shorter in length than a weld neck flange, the slip-on flange is used in areas where short tie-ins are necessary or space limitations necessitate its use. Two significant disadvantages, however, are the requirements of two fillet welds, one internal and one external, to provide sufficient strength and prevent leakage, as well as a life span about one-third that of the weld neck flange.

They are preferred over welding neck flanges by many users because of their lower initial cost. However, the total cost after installation is not much less than the welding neck because of the additional welding involved.

Threaded flange

The **threaded flange** shown above is similar to the slip-on flange, but the bore is threaded. Its principal value is that it can be assembled without welding. This feature makes the threaded flange well suited to extreme pressure services that operate at normal atmospheric temperatures and in highly explosive areas where welding may create a hazard.

Threaded flanges are not suited, however, for conditions involving temperatures or bending stresses of any significance, particularly when cyclic conditions exist, which may cause leakage through the threads. After just a relatively few cycles of expansion and contraction or movement caused by stress, the threaded flange no longer performs adequately.

Lap-joint flange

The **lap-joint flange** shown above is primarily used on carbon or low alloy steel piping systems. Attachment of the lap-joint flange to the piping system requires a lap-joint stub end.

The lap-joint flange and stub end assembly are used mainly in piping systems that necessitate frequent dismantling for inspection or routine maintenance. It is also used in the erection of large diameter or hard to adjust piping configurations because of its quick bolt hole alignment.

Reducing flange

Like the reducer fitting, the **reducing flange** shown above is used to make a reduction in the diameter of the pipe.

A reducing flange is most frequently used in installations with limited space. Crowded situations may necessitate the use of the reducing flange because it has a shorter overall length when compared to a weld neck flange and reducer-fitting configuration.

Be aware though that the flow should travel from the smaller size to the larger. If the flow were reversed, severe turbulence could develop.

Blind flange

The **blind flange** shown above serves as a function similar to that of a plug or cap. It is used to terminate the end of a piping system. The blind flange is basically a flange that does not have a hub or a bored center. Blind flanges have the face thickness of a flange, a matching face type, and similar bolting pattern.

Blind flanges can also be used to seal a nozzle opening on a pressure vessel.

Because it is bolted, the blind flange provides easy access to the interior of a vessel or pipe, unlike a cap that is welded.

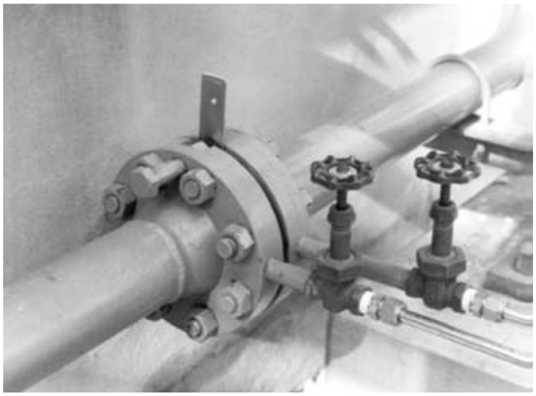
Orifice flange

Of the flanges discussed, the **orifice flange** (shown above) is the only one that actually performs a function.

The function of the orifice flange is to measure the rate of the flow of the commodity through the piping system. Orifice flanges are easy to recognize because they have a hole drilled through the face of the flange perpendicular to the pipe. They also have an additional set of bolts called **jack screws**.

These screws are used to help separate the flanges so inspection and/or replacement of the orifice plate can be performed.

The orifice flange is a single component of the **orifice flange union** assembly. The orifice flange union is composed of two orifice flanges, an orifice plate, bolts, nuts, jack screws, and two gaskets.



The orifice flange union is used to measure, or meter, the amount of pressure drop through the orifice plate. The length of pipe within the piping system where orifice flanges are installed and where these measurements are recorded is known as a **meter run.** The illustration above shows the orifice flange union assembly installed in a meter run.

The orifice plate, which is not typically furnished with the orifice union assembly package, looks similar to a large ring washer with a handle attached. When fully assembled, the orifice plate is sandwiched between the orifice flanges. Valve taps are inserted into pressure holes that allow for the attachment of field monitoring equipment so accurate measurements can be recorded.

Orifice flanges can be either weld neck, slip-on, or threaded.

The weld neck and threaded orifice flanges are manufactured in 300# and larger pound ratings. However, the slip-on orifice flange is only available as a 300# raised face flange.

Gaskets

The primary purpose of any flanged assembly is to connect piping systems in such a manner as to produce a leak-free environment. Hazardous and combustible materials and extreme pressures and temperatures require the utmost in safety precaution.

Creating a leak-proof seal between two connecting metal surfaces in an industrial setting is almost impossible. Therefore, gaskets perform a vital function in plant safety. Using a gasket material softer than two adjoining flanges is an excellent way to eliminate the possibility of a fluid escape. Gaskets can be made of materials such as asbestos, rubber, neoprene, Teflon, lead, or copper. Although asbestos gaskets are not used anymore, they still can be found in older piping systems, and when maintenance is required, these have to be replaced with a non-asbestos material gasket.

When bolts are tightened and flange faces are drawn together, the gasket material will conform to any imperfections in the flange faces to create a uniform seal.

The picture above shows three types of gaskets that can be found in piping systems.

They are **full face, flat ring**, and **metal ring**. **Full face** gaskets are used on flat face flanges. **Flat ring** gaskets are used on raised face flanges. **Metal rings** are used on ring-type joint flanges.

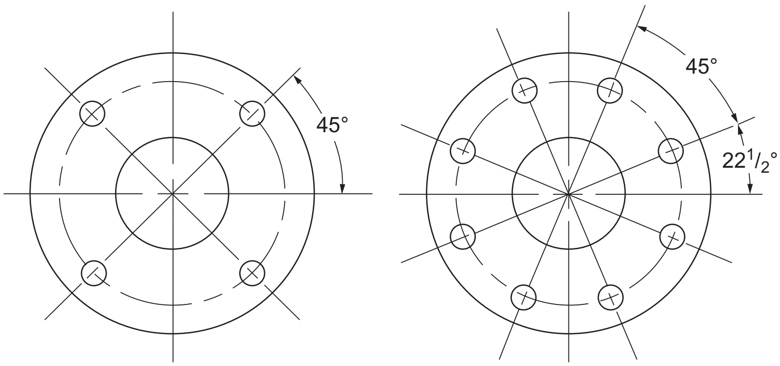
A gasket's thickness must be accounted for when dimensioning the piping system. The typical gasket has a thickness of 1/8″ (3.175 mm). At every occurrence of a flange bolting to a nozzle, two flanges joining one another, two valves joining one another, or a flange connecting to a valve, a gasket thickness must be added to the length of the pipe components. Figs. 4.34 and 4.35 show that a flat-ring gasket does occupy space. Although its only 1/8″ (3.175 mm) thick, a gasket cannot be ignored, and must be taken into consideration when dimensioning piping spools.

Bolts

Both stud bolts and machine bolts can be used for connecting flanges.

The most commonly used in the petro-chemical, oil, and gas industries are stud bolts.

Stud bolts Machine bolts



4 Bolt flange 8 Bolt flange

Shown above are the bolt spacing's for a 4 bolt and an 8 bolt flange

Shown next are the dimension and numbers required for the different flange ratings for stud bolts.

Forged steel flanges—Class 150

NPS (in.)	No. of Studs	Diameter of Stud (in.)	Length of Stud (in.)
1/2	4	1/2	2–1/2
3/4	4	1/2	2–1/2
1	4	1/2	2–3/4
1–1/4	4	1/2	2–3/4

Continued

NPS (in.)	No. of Studs	Diameter of Stud (in.)	Length of Stud (in.)
1–1/2	4	1/2	3
2	4	5/8	3–1/2
2–1/2	4	5/8	3–3/4
3	4	5/8	3–3/4
3–1/2	8	5/8	3–3/4
4	8	5/8	3–3/4
5	8	3/4	4
6	8	3/4	4–1/4
8	8	3/4	4–1/2
10	12	7/8	4–3/4
12	12	7/8	5
14	12	1	5–1/2
16	16	1	5–1/2
18	16	1–1/8	6
20	20	1–1/8	6–1/2
24	20	1–1/4	7

Forged steel flanges—Class 300

NPS (in.)	No. of Studs	Diameter of Stud (in.)	Length of Stud (in.)
1/2	4	1/2	2–3/4
3/4	4	5/8	3–1/4
1	4	5/8	3–1/4
1–1/4	4	5/8	3–1/2
1–1/2	4	3/4	3–3/4
2	8	5/8	3–3/4
2–1/2	8	3/4	4–1/4
3	8	3/4	4–1/2
3–1/2	8	3/4	4–1/2
4	8	3/4	4–3/4
5	8	3/4	5
6	12	3/4	5
8	12	7/8	5–3/4
10	16	1	6–1/2
12	16	1–1/8	7
14	20	1–1/8	7–1/4
16	20	1–1/4	7–3/4
18	24	1–1/4	8
20	24	1–1/4	8–1/4
24	24	1–1/2	9–1/4

Forged steel flanges—Class 400

NPS (in.)	No. of Studs	Diameter of Stud (in.)	Length of Stud (in.)
1/2	4	1/2	3–1/4
3/4	4	5/8	3–3/4
1	4	5/8	3–3/4
1–1/4	4	5/8	4
1–1/2	4	3/4	4–1/2
2	8	5/8	4–1/2
2–1/2	8	3/4	5
3	8	3/4	5–1/4
3–1/2	8	7/8	5–3/4
4	8	7/8	5–3/4
5	8	7/8	6
6	12	7/8	6–1/4
8	12	1	7
10	16	1–1/8	7–3/4
12	16	1–1/4	8–1/4
14	20	1–1/4	8–1/2
16	20	1–3/8	9
18	24	1–3/8	9–1/4
20	24	1–1/2	9–3/4
24	24	1–3/4	10–3/4

Forged steel flanges—Class 600

NPS (in.)	No. of Studs	Diameter of Stud (in.)	Length of Stud (in.)
1/2	4	1/2	3–1/4
3/4	4	5/8	3–3/4
1	4	5/8	3–3/4
1–1/4	4	5/8	4
1–1/2	4	3/4	4–1/2
2	8	5/8	4–1/2
2–1/2	8	3/4	5
3	8	3/4	5–1/4
3–1/2	8	7/8	5–3/4
4	8	7/8	6
5	8	1	6–3/4
6	12	1	7

Continued

NPS (in.)	No. of Studs	Diameter of Stud (in.)	Length of Stud (in.)
8	12	1–1/8	7–3/4
10	16	1–1/4	8–3/4
12	20	1–1/4	9
14	20	1–3/8	9–1/2
16	20	1–1/2	10–1/4
18	20	1–5/8	11
20	24	1–5/8	11–1/2
24	24	1–7/8	13

Forged steel flanges—Class 900

NPS (in.)	No. of Studs	Diameter of Stud (in.)	Length of Stud (in.)
1/2	4	3/4	4–1/2
3/4	4	3/4	4–3/4
1	4	7/8	5–1/4
1–1/4	4	7/8	5–1/4
1–1/2	4	1	5–3/4
2	8	7/8	6
2–1/2	8	1	6–1/2
3	8	7/8	6
4	8	1–1/8	7
5	8	1–1/4	7–3/4
6	12	1–1/8	7–3/4
8	12	1–3/8	9
10	16	1–3/8	9–1/2
12	20	1–3/8	10–1/4
14	20	1–1/2	11
16	20	1–5/8	11–1/2
18	20	1–7/8	13
20	20	2	14
24	20	2–1/2	17–1/2

Forged steel flanges—Class 1500

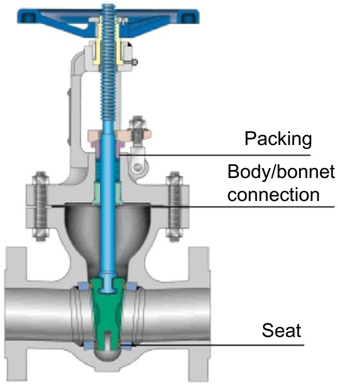
NPS (in.)	No. of Studs	Diameter of Stud (in.)	Length of Stud (in.)
1/2	4	3/4	4–1/2
3/4	4	3/4	4–3/4
1	4	7/8	5–1/4
1–1/4	4	7/8	5–1/4
1–1/2	4	1	5–3/4
2	8	7/8	6
2–1/2	8	1	6–1/2
3	8	1–1/8	7–1/4
4	8	1–1/4	8
5	8	1–1/2	10
6	12	1–3/8	10–1/2
8	12	1–5/8	11–3/4
10	12	1–7/8	13–1/2
12	16	2	15
14	16	2–1/4	16–1/2
16	16	2–1/2	18
18	16	2–3/4	19–1/2
20	16	3	21–1/2
24	16	3–1/2	24–1/2

VALVES

Valves: Types of valves

Gate valves—Used for ON-OFF shutdown

Gate valve

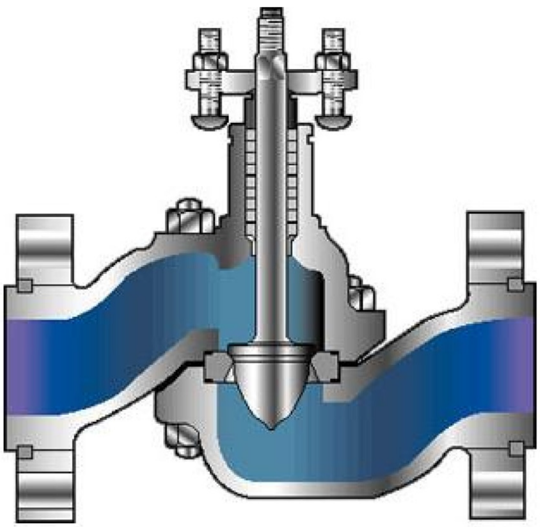


Gate valve internals

Knife gate valve

Globe valves—Used for throttling and control of flow, and for control valves.

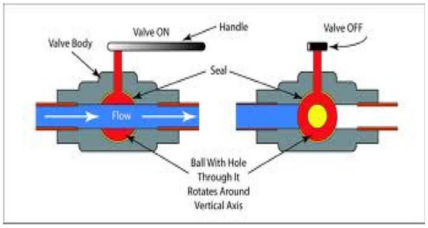
Globe valve



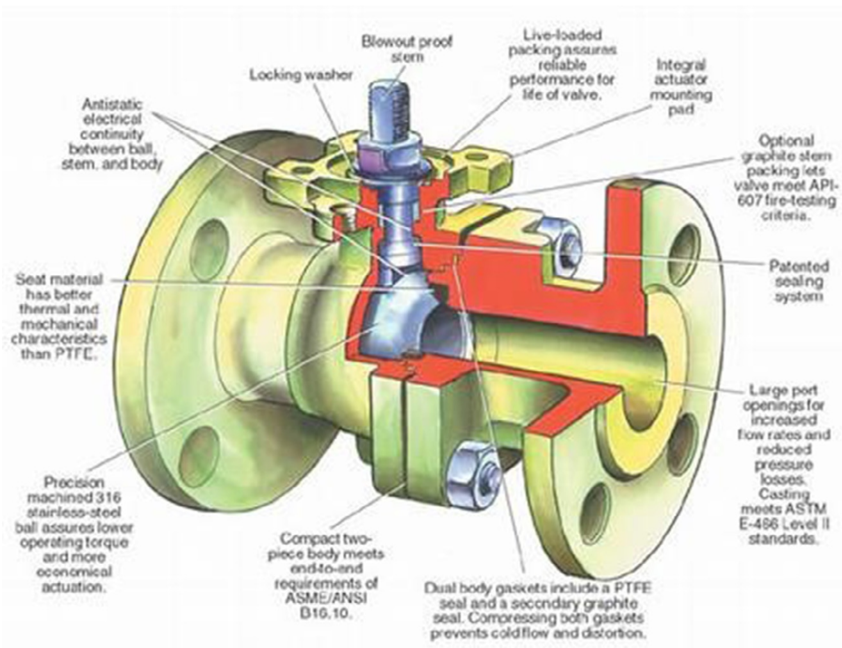
Globe valve internals

Ball valves—There are two types of ball valves: reduced port and full port, typical applications for these valves are air lines, process lines, gas lines, pigging lines (full port only) design and cost decides the type to be used.

Ball Valve



Flow Though a Ball Valve

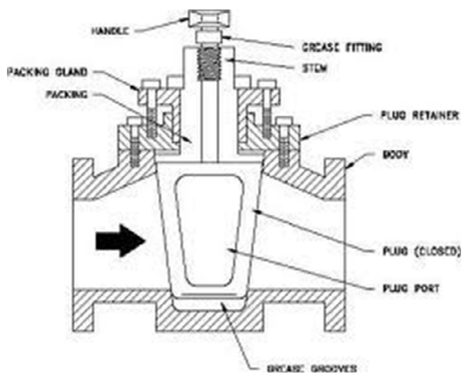


Ball Valve Internals

Plug valves—used in industrial processes, oil and gas, petro-chemical, refining, and pipelines. The advantage of the plug valve is that during the opening and closing of the valve, the valve disk and valve seat is separated and there is no friction and thus the sealing face has no abrasion, a soft seal is applied for sealing, so there will be no leakage in the process of closing.

Plug valve

Plug valve internals



Plug valve schematic

Plug valve

Butterfly valves—used throughout the process, oil and gas, pharmaceutical, food, brewing, and industrial industries for process, water, and fluids.

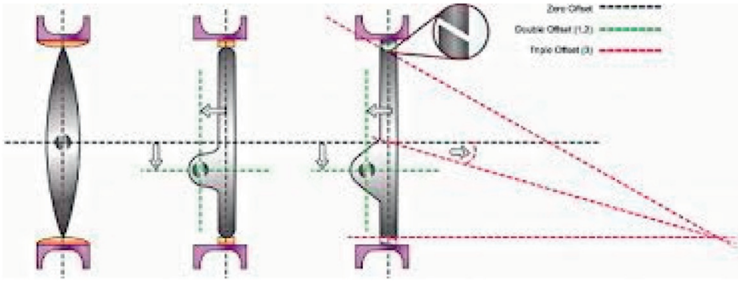
Types of butterfly valves include flanged, lug, wafer, and triple offset.

Lug Wafer Flanged

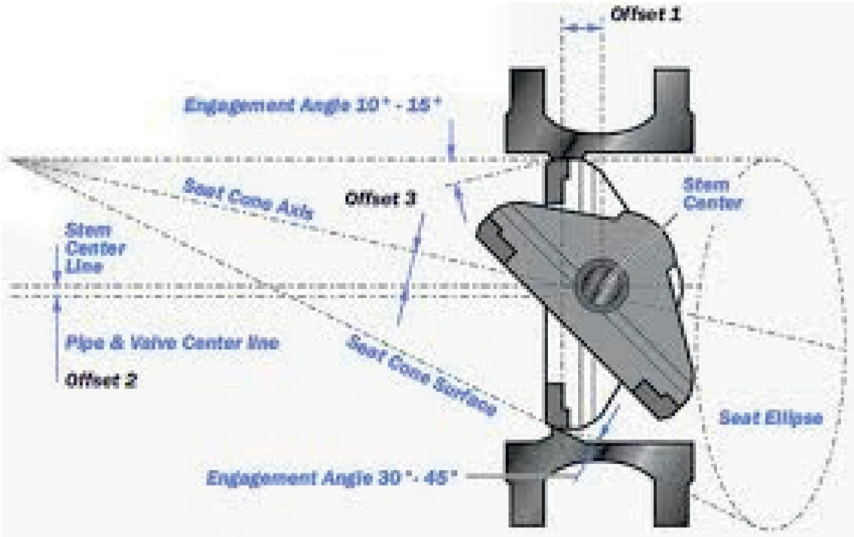
It should be noted that you never place a butterfly valve at a vessel nozzle, as the disk can penetrate inside the vessel nozzle.

A lug or wafer butterfly valve therefore could not be used as an isolation valve at a piece of equipment as for maintenance the valve could not be removed, as the line would not be isolated.

Triple offset butterfly valves—these valves are now being used more and more because of their ability to provide a good tight seal.



Triple Offset Butterfly Valve – Schematic



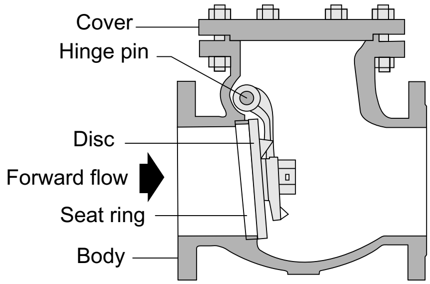
Triple Offset Butterfly Valve – Cross Section though seats

Check valves—used anywhere a return flow has to be prevented, used in all process facilities.

There are different types of check valves (also known as nonreturn valves).

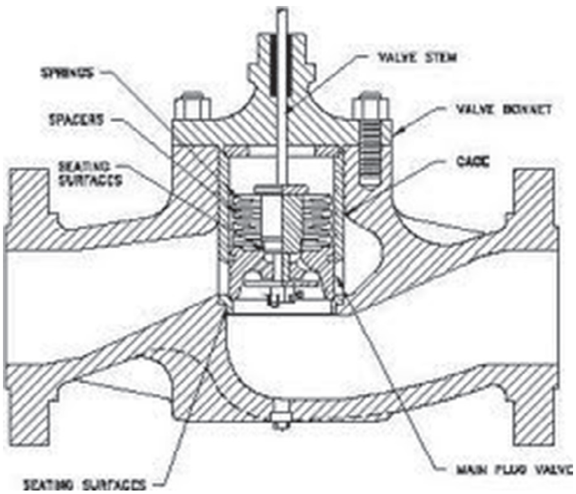
Swing check, spring type, wafer type—duo check, ball type, wafer type.

Swing check



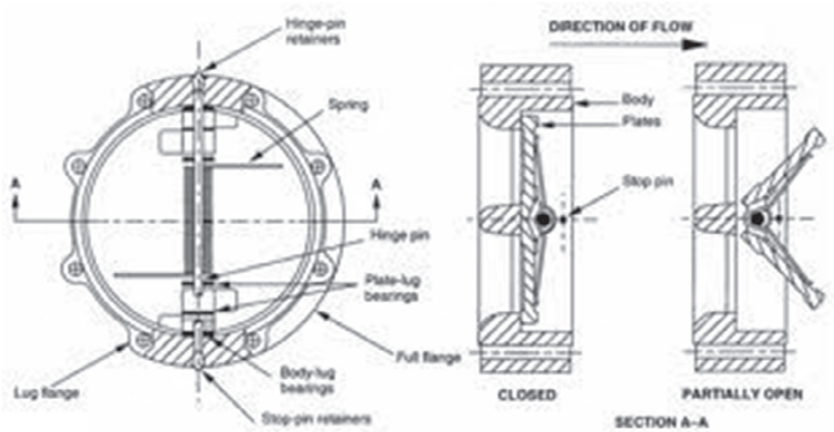
Swing check—schematic

(Shall only be used in horizontal or vertical lines (with flow upwards)



Nonreturn valve—spring type

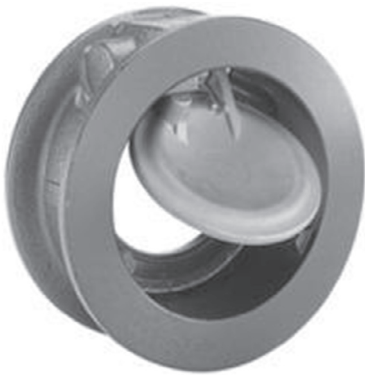
(Shall only be used in horizontal lines)



Wafer type—Duo check

(Shall only be used in the vertical with flow upwards)

Ball type Nonreturn valve



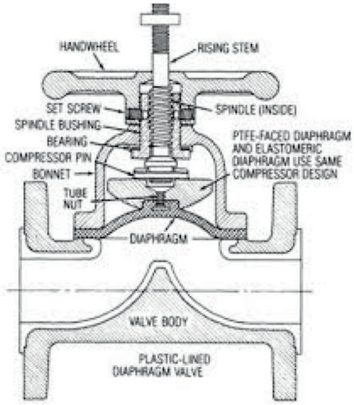
Wafer type check valve

(Shall only be used in the vertical with flow upwards)

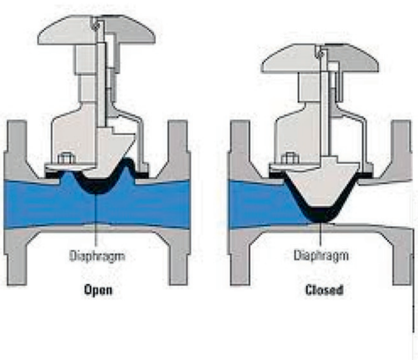
Diaphragm valve—used throughout the process industries as well as mining, food, pharmaceutical, they are primarily used in slurry services, water, and low-pressure service.

These valves are also known as "Saunders Valves" after the inventor who came across the idea after walking over a hose pipe in a South African mine, and noticed how the flow was reduced after stepping on the hose.

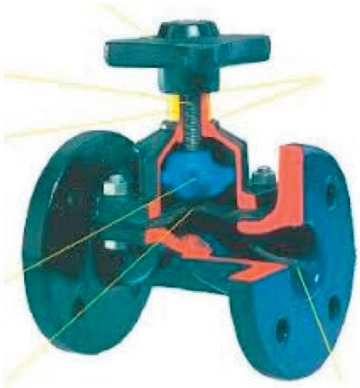
Diaphragm Valve



Diaphragm Valve – Schematic Section View



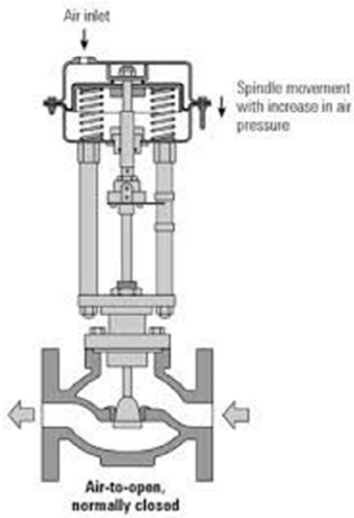
Diaphragm Valve – Schematic (Open & Closed Section View)



Sectional Detail of Diaphragm Valve

Control valves—used for the control of flow or pressure, generally (but not always) globe valves are used for this purpose.

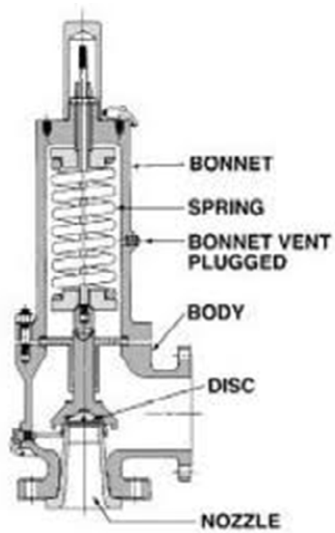
Control valve



Control valve—Schematic

Pressure relief valves—known as PRVs (pressure relief valves) or PSVs (pressure safety valves)**—**are a form of control valve as they are set to open at preset pressures, and relieve into a pressure relieving system such as a *Flare Header*.

Pressure relief valve (PRV)



Spring operated pressure
relief valve (PRV)—Shematic

2.2 PROCESS TERMS

HYDROCARBON STRUCTURES

A **Hydrocarbon** is a mixture of the atoms of hydrogen and carbon. It is important to know how and in what quantities they are mixed. Whether the hydrocarbon is in a liquid or vapor state must be known by the engineer.

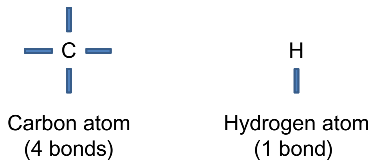
Crude oil is a hydrocarbon. Crude oil may be classified as **"Sweet"** or **"Sour,"** depending on its percentage of **"Mercaptans,"** which is a sulfur-bearing compound. **Sweet** streams have very low or no sulfur content, whereas **sour** streams are high in "mercaptans" the sulfur-bearing compound. Sour streams can be sweetened by removing the **Mercaptans**, if this is not done then the piping and equipment will be subject to corrosion by contact with the sulfur. The mercaptans can be separated out and sent to a unit such as a "Merox unit" (**Mercaptan** oxidation unit licensed by UOP [Universal Oil Products]).

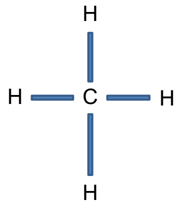
Crude Oil also contains salt, which must also be removed. This is done by putting the crude oil through a desalter, which is located in the crude unit of an oil refinery. The lightest hydrocarbon is methane which has one atom of carbon and four of hydrogen. This is shown as CH_4 The next lightest hydrocarbon is ethane which contains two atoms of carbon.

Nomenclature of hydrocarbons list the lightest 20 hydrocarbons by weight. Table 2.7 also shows the chemical composition of the hydrocarbons. These are referred as "The straight chain series of paraffin's."

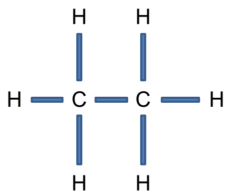
The first four hydrocarbons listed in the table 2.7 are normally gases, and have a very low boiling point. The next 13 listed are liquids. The last three are solids.

As a CH_2 is added, the hydrocarbon is heavier and the boiling point and melting point rise.

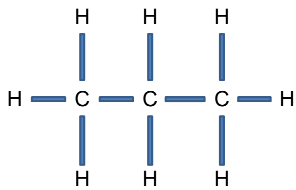




Methane structure
(CH_4)



Ethane structure
(C_2H_6)



Propane structure
(C_3H_8)

FRACTIONATION

Fractionation is the most widely used operation in process plants. Crude oil is first sent to the crude tower for fractionation. There can be several fractionation towers (also referred to as distillation towers) in a process plant. "Fractionation" is the separation of the lighter from the heavier fluid components, which occurs while the fluids are in contact with each other and are in equilibrium.

Equilibrium liquid is liquid that is at its boiling point due to pressure and temperature. Let us look at an example of this.

Let us assume that two pure separate liquids are placed in a container. One liquid (let us use pentane) is lighter than the other (let us use heptane) (refer to Table 2.7).

Table 2.7 Nomenclature of hydrocarbons

No. of C Atoms	Paraffin Name	No of C Atoms	Paraffin Name
1	Methane	11	Undecane
2	Ethane	12	Duodecane
3	Propane	13	Tridecane
4	Butane	14	Tetradecane
5	Pentane	15	Pentradecane
6	Hexane	16	Hexadecane
7	Heptane	17	Heptadecane
8	Octane	18	Octadecane
9	Noname	19	Nonadecane
10	Decane	20	Eicosane

So by application of the exact amount of heat, the lighter fluid (pentane) can be vaporized while the heavier fluid (heptane) remains a liquid. The two fluids are then separated into two containers, one fluid is a liquid, and the other is a vapor. Then as the vapor cools, it returns to its liquid state, and is pure pentane. This is what we call "simple fractionation."

As an engineer and designer you have to sometimes layout tower trays, so you must understand the principles behind what occurs in fractionation towers.

The layout and how to orientate tower trays will be addressed in Chapter 11.

Let us look at multiple fractionation. **Multiple fractionation** occurs when each tray in the tower has liquid of different weights and temperatures. As the hottest vapors rise they make contact with the cooler liquid on each tray. As the vapor cools, the heavier hydrocarbons drop out in liquid form and become part of the trays liquid. Conversely, as the hotter vapors heat the tray liquid, some of the lighter hydrocarbons vaporize and join the vapor on its upward journey. As a result of this, fractionation occurs on every tray in the tower. Each tray also contains liquid that is in equilibrium, that is liquid which is at its boiling point. As the liquid floods the uppermost tray, meeting the warmer vapors, fractionation occurs. As the liquids run down the tower, the lighter hydrocarbons are fractioned out, leaving a heavier liquid. Each tray down the tower contains a heavier liquid. The heavier the liquid, the hotter the temperature must be to vaporize the hydrocarbons.

Towers have **reboilers** located at the bottom of the tower. Hot vapors from these **reboilers** enter the towers vapor space below the bottom tray, making contact with the heavier hydrocarbons on the bottom tray. As the vapors rise, a calculated temperature drop occurs at each tray, maintaining just enough temperature to vaporize the lighter hydrocarbons and dropping the vapor temperature enough, so that the heavier hydrocarbons will condense out.

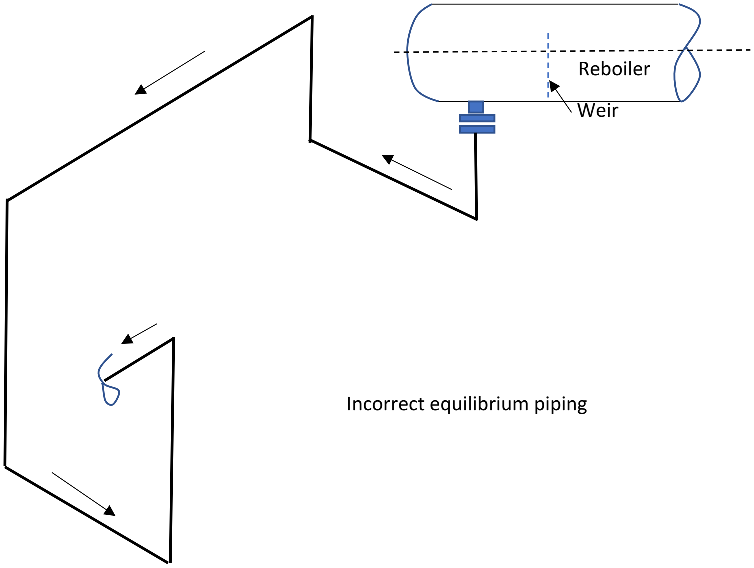
EQUILIBRIUM LIQUIDS

We talked about liquids that are in equilibrium at each tray. Equilibrium liquids require special attention by the engineer and designer. Remember we said at equilibrium the liquid is at its pressure and temperature is at its boiling point. If you were to design the piping in such a way that it would induce a very small amount of pressure drop, the equilibrium would start flashing, resulting in two-phase flow, an increased line velocity, and a fluid that is difficult to control and impossible to measure.

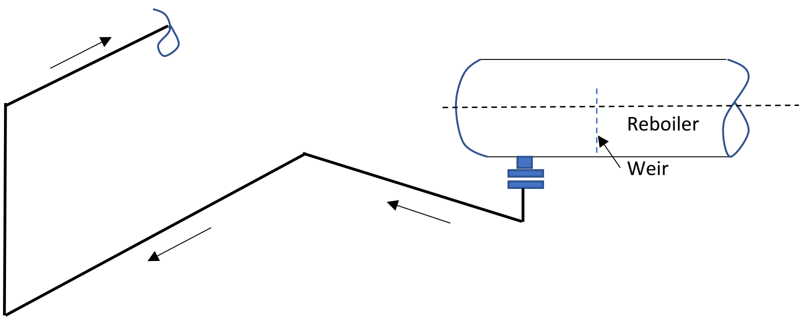
Flashing does not harm in some instances, however the engineer and designer must first recognize what liquids are in equilibrium, and when flashing can be tolerated.

The main streams that contain equilibrium liquids are any tray draw-off, tower bottoms, two-phase flow and reboiler draw-offs. The biggest problem usually occurs at the reboiler liquid draw-offs.

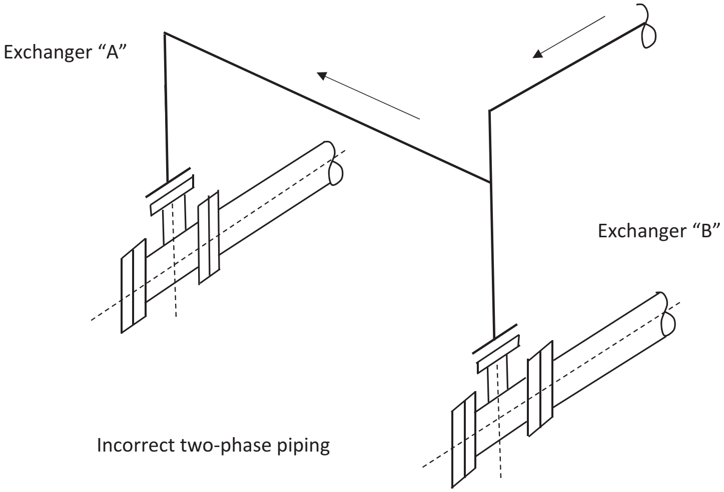
The following four diagrams show the incorrect and correct way of piping reboiler liquid draw-offs.



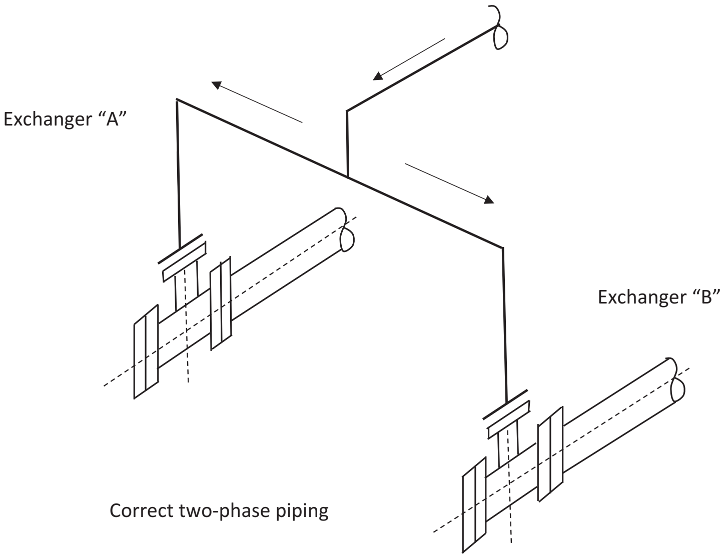
Incorrect equilibrium piping



Correct equilibrium piping



Incorrect two-phase piping



Correct two-phase piping

2.3 PIPING CODES

ASME

ASME International was founded in 1880. With the increase in industrialization in the USA, engineers realized the need for standardization. In 1883, a committee on standards and gauges was created, and a paper was presented on the need to adopt a set of rules for conducting boiler tests that would be accepted by engineers as a standard code of practice.

In 1884, ASME's first standard "Uniformity for Testing Methods for Boilers" was published. After the first standard ASME decided that pipes and pipe threads should be standardized a serious problem facing engineers at the early part of the 1900s was exploding boilers. In 1915, ASME published the boiler and pressure vessel code to help address these problems. This was the beginning of the codes, as we know them today. These codes are revised and updated every few years as industry changes and improvements dictate.

ASME's Council on Standards and Certification overseas six supervisory boards and four advisory boards, which manage more than 700 committees and 4500 volunteer members—most of whom are working engineers. Some of the best technical minds in the world volunteer their time and acumen to develop these standards that enhance public safety and also promote global trade.

What are standards? They are "A vehicle of communication for producers and users." They serve as a common language, defining quality and establishing safety.

There are many ASME standards, but the most common ones used are:

- B31.1 Power Piping
- B31.3 Process Piping
- B31.4 Pipeline Transportation Systems for Liquids and Slurries
- B31.5 Refrigeration Piping and Heat Transfer Components
- B31.8 Gas Transmission and Distribution Piping Systems
- B31.9 Building Services Piping
- B31.11 Slurry Transportation Piping Systems
- B31.12 Hydrogen Piping and Pipelines
- B31.E Standards for the Seismic Design and Retrofit of Above Ground Piping Systems
- ASME BPV Code, Section VIII, Division 1 and Division II

ANSI

The American National Standards Institute (ANSI) has served in its capacity as administrator and coordinator of the United States private sector voluntary standardization system for more than 90 years. Founded in 1918 by five engineering societies and three government agencies, the Institute remains a private, nonprofit membership organization supported by a diverse constituency of private and public sector organizations. The American National Standards Institute (ANSI) is a private nonprofit organization that oversees the development of standards for products, services, processes, systems, and personnel in the United States. The organization also coordinates US standards with international standards so that American products can be used worldwide. ANSI is also actively engaged in accrediting programs that assess conformance to standards—including globally recognized cross-sector programs such as the ISO 9000 (quality) and ISO 14000 (environmental) management systems. These standards ensure that the characteristics and performance of products are consistent, that people use the same definitions and terms, and that products are tested the same way. ANSI also accredits organizations that carry out product or personnel certification in accordance with requirements defined in international standards. **ANSI** standards became incorporated under **ASME**, and **the ASME** title is now used.

Some examples of ANSI Standards

- (ANSI) ASME B16.5 Pipe Flanges and Fittings
- (ANSI) ASME B16.9 Factory Made Wrought Butt Welding Fittings
- (ANSI) ASME B16.11 Forged Fittings, Socket Weld and Threaded
- (ANSI) ASME B16.34 Valves—Flanged, Threaded and Welding End

ASTM

ASTM International, known until 2001 as the American Society for Testing and Materials (ASTM), is an international standards organization that develops and publishes voluntary consensus technical standards for a wide range of materials, products, systems, and services.

ASTM was founded in 1898 as the American Section of the International Association for Testing and Materials, predates other standards organizations such as BSI (1901), DIN (1917), and ANSI (1918).

ASTM has a dominant role among standards developers in the United States, and claims to be the world's largest developer of standards. Using a consensus process, ASTM supports thousands of volunteer technical committees, which draw their members from around the world and collectively develop and maintain more than 12,000 standards.

Some examples of ASTM standards:

- ASTM A36 Standard Specification for Carbon Structural Steel
- ASTM A53 Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless
- ASTM A106 Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service
- ASTM A304 Standard Specification for Carbon and Alloy Steel Bars Subject to End-Quench Hardenability Requirements

API

The American Petroleum Institute (API) is the only national trade association that represents all aspects of America's oil and natural gas industry. It represents about 400 corporations involved in production, refinement, distribution, and many other aspects of the petroleum industry. The American Petroleum Institute traces its beginning to World War I, when Congress and the domestic oil and natural gas industry worked together to help the war effort. API Standards enhance the safety of industry operations, assure quality, help keep costs down, reduce waste, and minimize confusion. They help speed acceptance and bring products to market quicker. And they avoid having to reinvent the wheel every time a product is manufactured.

Since 1924, the API has been a cornerstone in establishing and maintaining standards for the worldwide oil and natural gas industry. Our work helps the industry invent and manufacture superior products consistently, provide critical services, ensure fairness in the marketplace for businesses and consumers alike, and promotes the acceptance of products and practices globally.

The association's chief functions on behalf of the industry include advocacy and negotiation with governmental, legal, and regulatory agencies; research into economic, toxicological, and environmental effects; establishment and certification of industry standards; and education outreach. API funds and conducts research related to many aspects of the petroleum industry.

Some of the many standards include

- API 510 Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration
- API 570 Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems
- API 572 Inspection of Pressure Vessels
- API 579 Fitness-for-Service
- API 610 Centrifugal Pumps for General Refinery Services
- API 6D Steel Gate, Plug, and Check Valves for Pipeline Service
- API 620 Design and Construction of Large Welded, Low-Pressure Storage Tanks
- API 653 Tank Inspection, Repair, Alteration and Reconstruction

NFPA

The **National Fire Protection Association (NFPA)** is a United States Trade Association, with some international members that creates and maintains private, copyrighted, standards, and codes for usage and adoption by local governments. This includes publications from model building codes to the many on equipment utilized by firefighters while engaging in hazardous material (hazmat) response, rescue response, and some firefighting.

The **NFPA** was formed in 1896 by a group of insurance firms with the stated purpose of standardizing the new and burgeoning market of fire sprinkler systems. The scope of the NFPA's influence grew from sprinklers and fire extinguishers to include building electrical systems (another new technology), and then into almost all aspects of building design and construction.

Its original membership was limited to insurance underwriting firms and there was no representation from the industries the NFPA sought to control. This changed in 1904 to allow other industries and individuals to participate in the development of the standards to be promulgated by the NFPA. The first fire department to be represented in the NFPA was the New York City Fire Department in 1905, although their participation has declined steadily since then. Today, the NFPA includes representatives from some fire departments, many fire insurance companies, many manufacturing associations, some trade unions, many trade associations, and engineering associations.

NFPA membership totals more than 70,000 individuals around the world. NFPA is responsible for 300 codes and standards that are designed to minimize the risk and effects of fire by establishing criteria for building, processing, design, service, and installation in the United States, as well as many other countries. Its more than 200 technical code- and standard-development committees have over 6000 volunteer seats. Volunteers vote on proposals and revisions in a process that is accredited by the American National Standards Institute (ANSI).

Some of the more widely used standards are:

- NFPA 1 Fire Code: Provides requirements to establish a reasonable level of fire safety and property protection in new and existing buildings.
- NFPA 30 Flammable and Combustible Liquids Code
- NFPA 54 National Fuel Gas Code: The safety benchmark for fuel gas installations.
- NFPA 55 Compressed Gases and Cryogenic Fluids Code
- NFPA 58 Liquefied Petroleum Gas Code
- NFPA 59A Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)
- NFPA 70 National Electric Code: The world's most widely used and accepted code for electrical installations.
- NFPA 101 Life Safety Code: Establishes minimum requirements for new and existing buildings to protect building occupants from fire, smoke, and toxic fumes.
- NFPA 400 Hazardous Materials Code

BSI

BSI Group was founded as the Engineering Standards Committee in London in 1901. It subsequently extended its standardization work and became the British Engineering Standards Association in 1918, adopting the name British Standards Institution in 1931 after receiving its Royal Charter in 1929. In 1998, a revision of the Charter enabled the organization to diversify and acquire other businesses, and the trading name was changed to BSI Group.

The Group now operates internationally in 150 countries. The core business remains standards and standards-related services, although the majority of the Group's revenue now comes from management systems assessment and certification work.

As the UK's National Standards Body, BSI is responsible for producing and publishing British Standards and for representing UK interests in international and European standards organizations such as ISO, IEC, CEN, CENELEC, and ETSI. Formal British Standards are titled BS (for British Standard) XXXX [—P]: YYYY where XXXX is the number of the standard, P is the number of the part of the standard (where the standard is split into multiple parts) and YYYY is the year of publication.

BSI produces standards on a wide range of products, services, and processes; from nuts and bolts to sustainability, risk, business continuity management, and nanotechnology. BSI produces British Standards, and, as the UK's National Standards Body, is also responsible for the UK publication, in English, of international and European standards. BSI is obliged to adopt and publish all European Standards as identical British Standards (prefixed BS EN) and to withdraw preexisting British Standards that are in conflict. However, it has the option to adopt and publish international standards (prefixed BS ISO or BS IEC).

Some examples of the more widely used BSI standards in oil and gas are:

- BS 4 Structural Steel Sections—Part 1
- BS 10 Specification for Flanges and Bolting for Pipes, Valves, and Fittings
- BS 21 Pipe Threads
- BS 1560 Circular Flanges for Pipes, Valves, and Fittings
- BS 1570 Flanged and Butt Welding End Steel Plug Valves for the Petroleum Industry
- BS 1600 Specification for Dimensions of Steel Pipe for the Petroleum Industry

DIN

DIN, the German Institute for Standardization, offers stakeholders a platform for the development of standards as a service to industry, the state, and society. There are over 45,000 German and English DIN standards covering a variety of subjects: Standardization, Terminology, Quality Documentation, Environment, Health Protection, Safety, Natural Sciences, Health Care Technology, Metrology and Measurement, Testing, Energy, Image Technology, Mechanical Systems and Components for General Use, Fluid Systems and Components, Machine Tools, Automation, Welding, Surface Treatment, Electrical Engineering, Electronics, Telecommunications, Information Technology, Office Equipment, Vehicle Engineering, Materials Handling, Aircraft and Space Vehicle Engineering, Packaging, Textile and Leather, Clothing, Agriculture, Food Technology, Housekeeping, Chemical Engineering, Mining, Paint, Metallurgy, Paper Industries, Ceramics and Glass, Construction, and Civil Engineering.

Some examples of DIN standards are:

- DIN EN 10220 Seamless Steel Pipes and Tubes—Dimensions, Conventional Masses per Unit Length
- DIN EN 10253–1 Butt—welding fittings—Part 1
- DIN 2448/2458 Pipes Dimensions and Weights
- DIN 2527 Flanges
- DIN 28034 Flange Joints for Process Vessels—Weld-neck flanges for pressurized vessels

ISO

The **International Organization for Standardization (ISO)** (French: Organisation internationale de normalisation) known as **ISO** is an international standard-setting body composed of representatives from various national standards organizations.

Founded on February 23, 1947, the organization promotes worldwide proprietary, industrial, and commercial standards. It is headquartered in Geneva, Switzerland. It was one of the first organizations granted general consultative status with the United Nations Economic and Social Council.

Some examples of ISO standards:

- ISO 7-1:1994-05
  Pipe threads where pressure-tight joints are made on the threads—Part 1: Dimensions, tolerances, and designation
- ISO 7-2:2000
  Pipe threads where pressure-tight joints are made on the threads—Part 2: Verification by means of limit gauges
- ISO 49:1994
  Malleable cast iron fittings threaded to ISO 7–1
- ISO 228-1:2000
  Pipe threads where pressure-tight joints are not made on the threads—Part 1: Dimensions, tolerances, and designation
- ISO 228-2:1987
  Pipe threads where pressure-tight joints are not made on the threads; Part 2: Verification by means of limit gauges
- ISO 264:1976

PED

The Pressure Equipment Directive (97/23/EC) was adopted by the European Parliament and the European Council in May 1997. It initially came into force on November 29, 1999. From that date until May 29, 2002 manufacturers had a choice between applying the pressure equipment directive or continuing with the application of the existing national legislation. From May 30, 2002 the pressure equipment directive became obligatory throughout the EU.

The directive provides, together with the directives related to simple pressure vessels (2009/105/EC), transportable pressure equipment (99/36/EC), and aerosol dispensers (75/324/EEC), for an adequate legislative framework on European level for equipment subject to a pressure hazard.

Some examples of PED standards are:

- EN 1092–1:2007 Flanges and their joints—Circular flanges for pipes, valves, fittings, and accessories, PN designated—Part 1: Steel flanges
- EN 1515–4:2009 Flanges and their joints—Bolting—Part 4: Selection of bolting for equipment subject to the Pressure Equipment Directive 97/23/EC
- EN 1983:2006 Industrial valves—Steel ball valves
- EN ISO 4126–5:2004 Safety devices for protection against excessive pressure—Part 5: Controlled safety pressure relief systems (CSPRS) (ISO 4126–5:2004)

CHAPTER

3 Fundamentals of plant layout design—Plot plans

3.1 FUNDAMENTALS OF PLANT LAYOUT DESIGN

What is plant layout design…?

Plant layout design is the development of equipment and piping layouts for the process, oil and gas, and petro-chemical industries.

The engineer involved in the design must have an understanding of the following:

- What is the plant designed to do…?
- How is the equipment maintained and operated…?
- The engineer must be able to develop layouts and documents during both the conceptual and study phases of a project.
- A common sense approach and reasoning abilities.
- Most importantly the ability to generate a safe, operable maintainable, constructible, and cost-effective layout, within a specified project time.

A plant layout engineer is skilled in the layout and arrangements of process plant facilities. The engineer must demonstrate his or her technical abilities and creative talents along with a good amount of common sense type approach and problem solving to the layout as well as a good understanding of how the process equipment works. The layout engineer has to abide by short schedules and pressure from not only the client but also his peers. The layout engineer must at all times adhere to making sure that the plant arrangement meets industry codes, is safe operable and maintainable.

The plant layout engineer is responsible for producing a constructible design as well as an economic one. All available real estate must be used to its maximum ensuring practical road layouts, safely located drop zones around equipment, adequate laydown areas, access roads, egress around equipment, and safety egress from units. The engineer must be aware of the requirements of all disciplines involved in the plant, and these must be incorporated into the design. A compromise between the disciplines must sometimes be taken into consideration, and no one discipline can have the final say as to the layout, it has to be an agreed layout with every discipline buying in to the final arrangement, before approval by the client.

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00003-5

3.2 EQUIPMENT LAYOUT AND PLOT PLANS

The layout engineer starts with a conceptual plot study, which includes all the preliminary locations of major units and equipment locations, roads, buildings, access roads, major and minor roads, fencing, flare location based on wind direction, location of heaters, process units, pipe racks and sleeper ways, wind rose (wind direction) Plant North and true North. The local topographical and state and county maps are required as part of the input information to the plot.

Setting the equipment locations requires input from construction with regard to erection sequences, and any special construction problems that might be incurred. Once the equipment has been located coordinates in two directions, usually Northings and Easting's (but sometimes can be Southings and Westing's) are set for the precise location. As well as the coordinates, the equipment elevations must be set; these can be by centerline, tangent line, or bottom of baseplate.

If structures are required due to process head requirements and operability, the provision must be made to include the location of stairways, ladders, and operating platforms.

Provision must be made to satisfy all operational, maintenance, and access requirements around equipment, as well as egress and escape routes around and from equipment and hazardous areas.

Planning must be taken into consideration for unobstructed areas where any necessary structural members are required to facilitate plant maintenance requirements.

All equipment nozzles must be established identifying elevations, orientations to satisfy process, utility, and instrumentation requirements.

Safety and plant maintenance operations items such as fire hydrants, monitors, deluge systems, safety showers, utility stations, filters, silencers analyzer houses and enclosures must be located and thought given to not only the location but to the operation and maintenance of these and other safety- and maintenance-related items.

The **plot plan** is the focal point not only for all the disciplines but also for the client. As such, the layout engineer becomes also the focal point for all activities. By taking extra care in all aspects of the plot development, significant savings can be made to the final cost of the project, not to mention shortened construction schedules. Creating a well-designed facility requires meeting not only client specifications but national and local government codes and regulations as well. At all times, the engineer must adhere to the best engineering design practices for a safe maintainable and operable plant.

Before the layout engineer can start plot plan development, both **"Project Input Data"** and **"Project Design Data"** has to be established.

3.3 PROJECT INPUT DATA

There is a vast amount of input data required throughout the life of a project, the data basically falls into three categories:

- Project design data.
- Vendor data.
- Internally (project) generated engineering data.

PROJECT DESIGN DATA

The Project Design Data also falls into three basic categories:

This will include the plants geographic location and its proximity to roads railways waterways and local habitats.
It will also include not only local and national codes and regulations, but the plant area topography and climate conditions, including seismic considerations.
The project design data will also specify whether it is a green field project (a new site) or a brownfield project (within an existing facility).

This information is required before the start of the plot plan development phase.

VENDOR DATA

This includes all of the following purchased equipment:

Specialty items,
Bulk items,
Pumps,
Compressors,
Air coolers,
Exchangers,
Furnaces,
Heaters,
Stacks,
Silencers,
Control and safety relief valves,
Strainers and silencers,
Level instruments
Fire monitors and deluge systems, and
Storage tanks, sphere's, etc.

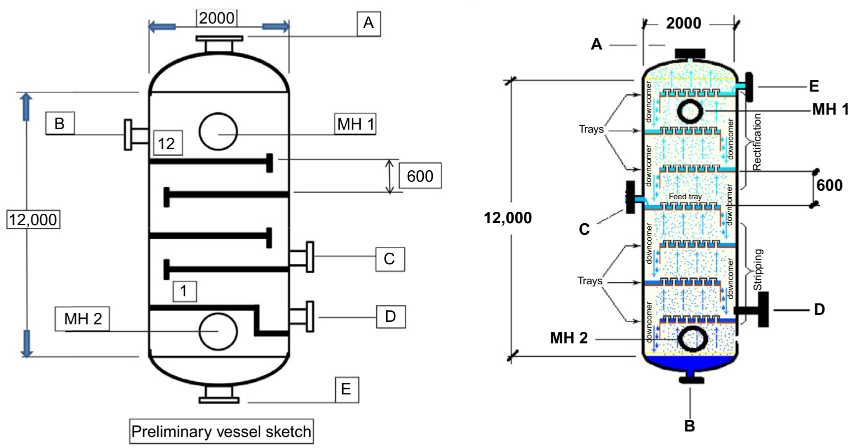
All these items require preliminary vendor drawings for the development of preparing.

Preliminary piping layouts to enable the proving and thus the development of the plot plan.

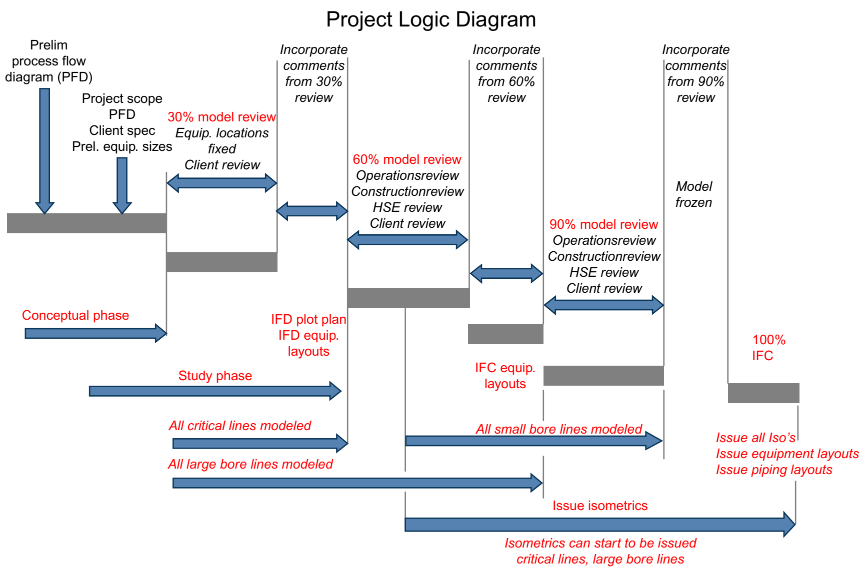
Final certified drawings are not usually required until the detail engineering phase.

INTERNALLY GENERATED ENGINEERING DATA

This type of data is provided by the supporting project disciplines such as mechanical, instrumentation, etc.



3.4 PROJECT LOGIC DIAGRAM



3.5 PLOT PLANS—BASIS FOR DESIGN

When starting plot plan development, the following items must be taken into consideration and adhered to.

Layout philosophy, industry abbreviations, and symbols for equipment, plant, and piping:

Both the client and engineering design house layout philosophies and plant and piping spacing specifications must be adhered to the clients philosophies take precedent however in the absence of these or for the improvement and updating to current standards then the engineering design house specifications can be used.

Most clients and engineering companies now follow the PIP (Process Industry Practice) plant layout design specifications. So, this will normally be used for the layouts.

Piping terminology, piping codes and standards:

This encompasses client and engineering design house standards as well as

ASME (American Society of Mechanical Engineers), **ANSI** (American National Standards Institute),
ASTM (American Society for Testing and Materials, **API** (American Petroleum Institute),
NFPA (National Fire Protection Association), **BSI** (British Standards Institute),
DIN (German Institute for Standardization),
ISO (International Organization for Standardization), **PEP** (Pressure Equipment Directive)

Plant layout specification:

The layout specifications for the spacing of equipment will be dictated by the PIP (Process Industry Practice), client, engineering house, and by the specified requirements of the equipment vendors if applicable.

Components of layout specification:

What is required? What major equipment is required to be placed on the plot plan, this must include smaller items as well as pumps and filters. How this equipment is placed is based on the spacing specification requirements and the piping layout of the large bore piping.

Plot plans and general arrangements:

These will be developed based on the previous points already discussed.

Definitions must be established, for example, does the location of the equipment depend on wind direction, airflow, access for maintenance, and removable items from equipment.

Development of plot plan:

There are different types of plot plans,

Overall plot plan—This is the major plan and will show the whole plant, all equipment, buildings, enclosures, and pipe racks including all major and secondary roads, fencing, and boundaries, and surrounding real estate.

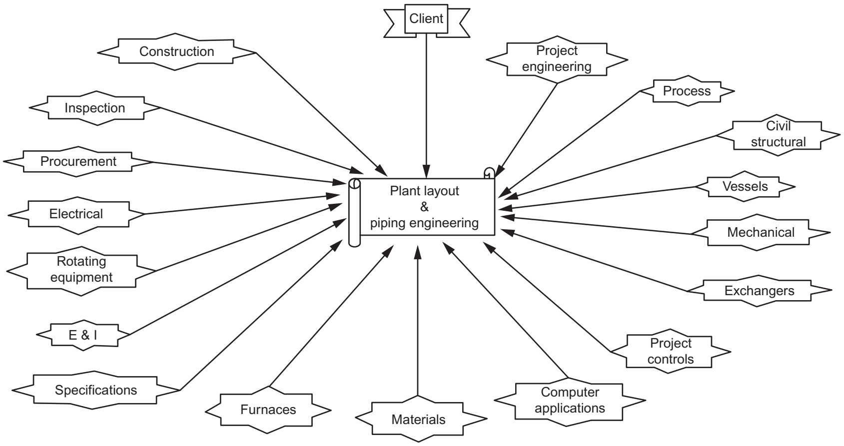
Equipment location plans:

The equipment location plans will show all major equipment spacing, interconnecting pipe racks, major and secondary roads, paving, graveled areas, access and egress ways, and drop areas. These plan drawings will be broken down by process and utility areas.

Pipe racks:

Drawings will be prepared showing the major and secondary pipe racks including pipe way sleepers.

This diagram shows the departments and personnel that the plant engineer can expect to work with throughout the engineering phase of a project



The plot plan:

The plot plan is one of the key documents that will be produced during the FEED and engineering phase of any project.

The plot plan is developed at the proposal stage of the project.

The activities involved with plot plan development, equipment layout, and piping design, account for the significant portion of project engineering costs.

These activities and costs become a focal point for not only the client but also project management, as well as construction, operations, HSE, and all the supporting disciplines.

It is important that the design engineer must appreciate that the thought, time, and care spent during not only the early engineering phases of the project, but also throughout the project can help shorten construction schedules and therefore lower overall project costs, but also make the plant more operable, maintainable, and most importantly safer.

The engineer must be conscious of the constructability, operability, maintenance, and safety aspects of the layout design.

The plant layout engineer shall be responsible for the conceptual and preliminary development of the process unit plot plans (equipment arrangements).

The engineer shall also be responsible for:

Routing of the major above and below grade piping
Identification of critical lines
Locations of preliminary expansion loops for piping on pipe racks
Locations of anchor bays on pipe racks and sleeper ways
Layout of equipment and its associated infrastructure
Design and layout of associated structures, platforms, stairs, and ladders
Locations of relief valve platforms
Locations of major and secondary roadways
Location of flare stacks and process units
Locations of egress ways and access routes

To develop and produce a well-designed process plant involves meeting all the client specifications as well as local and government codes and regulations, and adhering to industry design engineering codes and practices such as ASME and API, NFPA, etc.

When planning a plot plan (base plot) there are mandatory functions that must be adhered to as the basis for the plot.

All equipment locations have to be set; this activity will include input from construction, to establish erection sequences and any problems that might be associated with setting large pieces of equipment.

The equipment location coordinates in two directions must be set along with the equipment elevations, by setting the centerline, tangent, or bottom of baseplate.

Structures have to be designed, including the location of stairways, ladders, and platforms.

Provision must be made for, to satisfy all operational maintenance, safety, and access requirements around equipment.

Planning for unobstructed areas for any necessary structural members that might be required to facilitate all plant maintenance requirements.

All equipment nozzles must be established satisfying all process, utility, and instrument requirements.

All safety items such as fire hydrants, monitors, safety showers, filters, silencers, analyzer houses, deluge systems must be located with thought given to the location and operation and maintenance of these and other items.

The major documents and information that are required in the development of the plot plan are:

PFD (Process Flow Diagram)
P&ID (Process and Instrumentation Diagram)
Land, survey maps, and geo technical data
Local and National Regulations
Available Real Estate drawings
Soil and Climate conditions

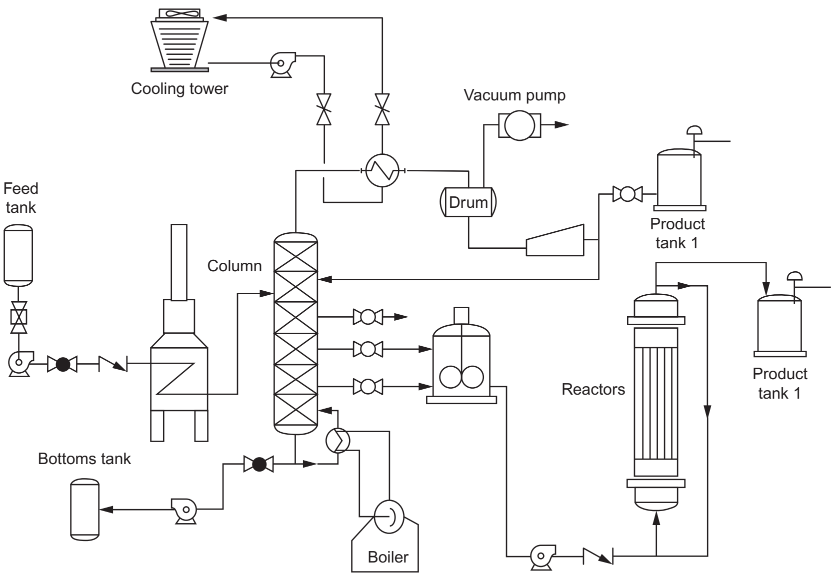
Client Philosophy and needs
The Process Flow diagram (and if available early P&IDs) sets the flow directions and thus the order of equipment placement.

The land, survey maps, and real estate drawings show the available plot space to work with and locations of roads, railroads, and any local housing and buildings.

Soil, climate conditions, prevailing winds, local and national regulations, as well as client philosophy all have a significant impact on the plot development.

PFD—PROCESS FLOW DIAGRAM

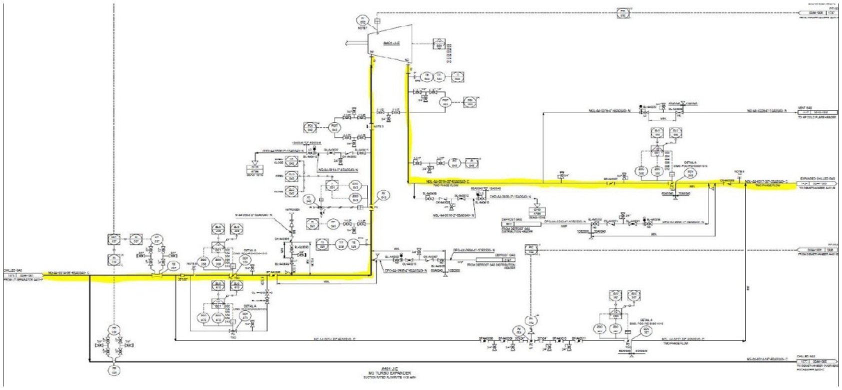
Process flow diagram or PFD



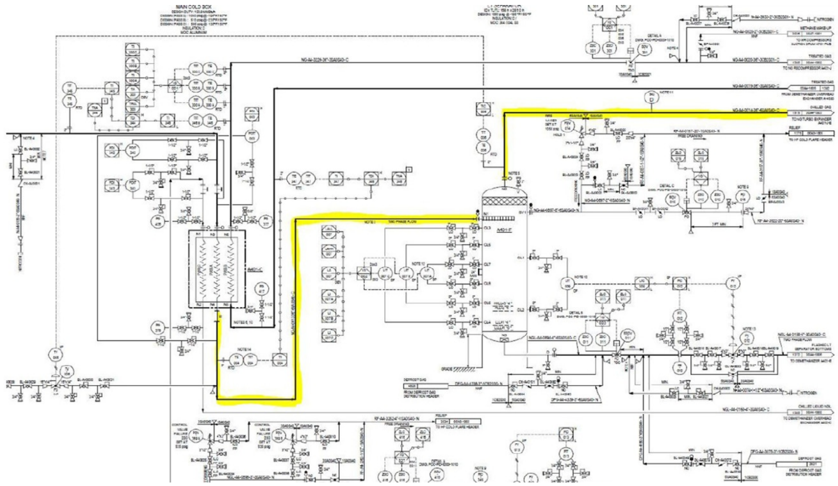
Shown above is a typical process flow diagram (PFD), what this shows us is an arrangement of the equipment in order of process flow sequence, and thus gives us an indication of how to place the equipment relative to each other on the plot plan. So when we look at the plot plan and review it against the PFD we will see the same sequence of equipment.

P&IDS

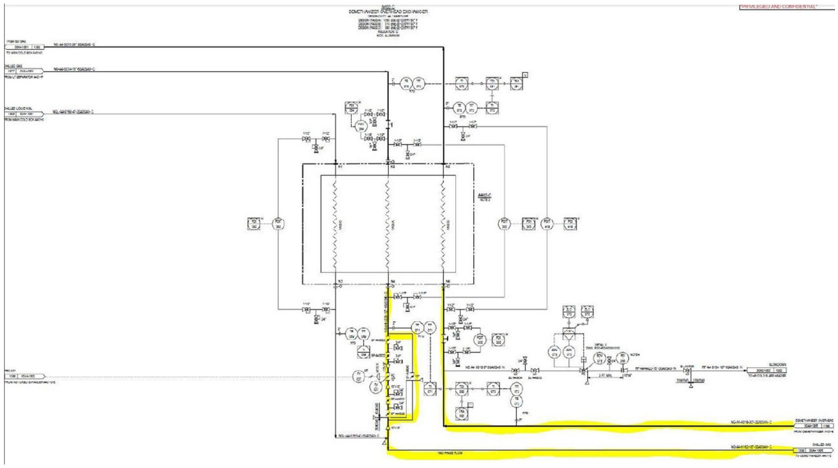
The following six drawings on the next pages are of P&IDs for a unit in an LNG plant. Highlighted on each P&ID are the major and critical lines that will determine the location and spacing of the equipment for this unit. The following pages will show how the P&ID is developed into a plot plan, equipment drawing, and a 3D model.



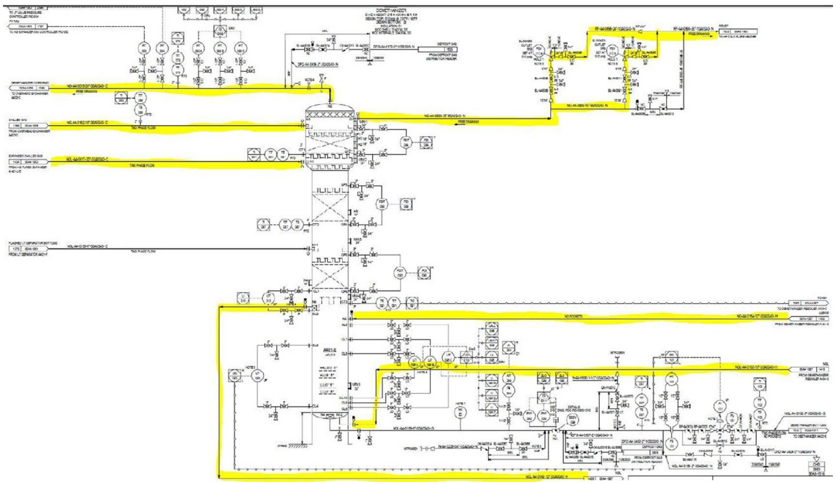
P&ID 1



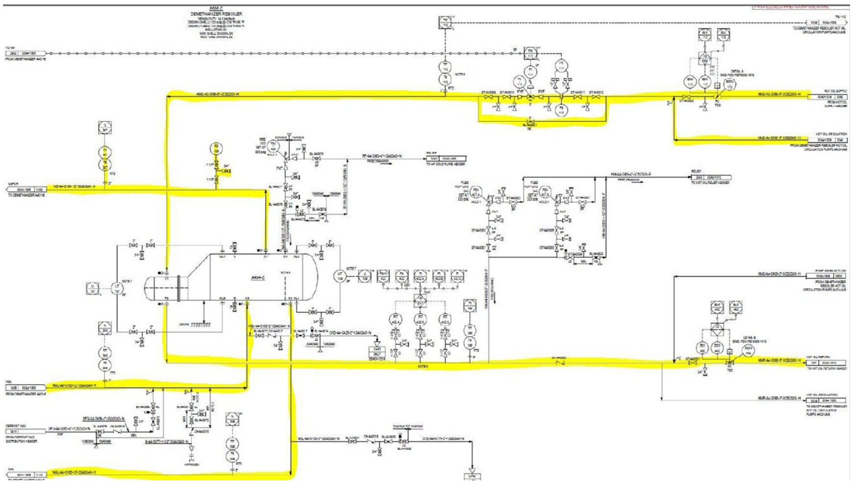
P&ID 2



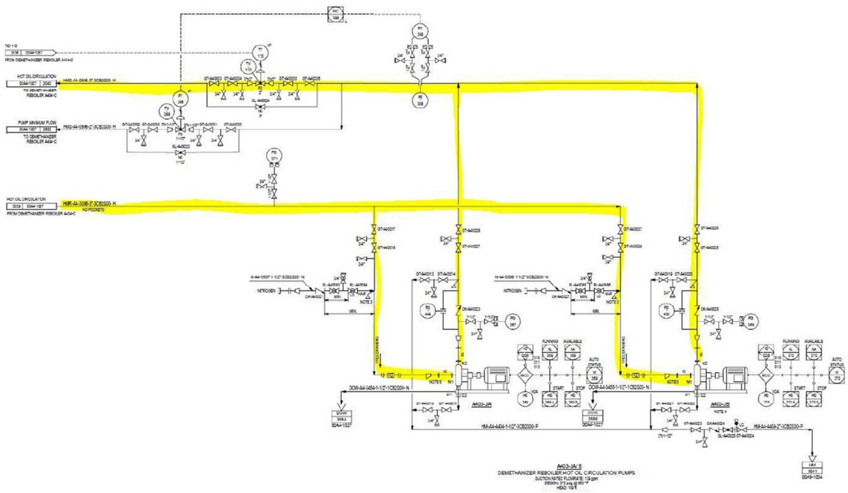
P&ID 3



P&ID 4

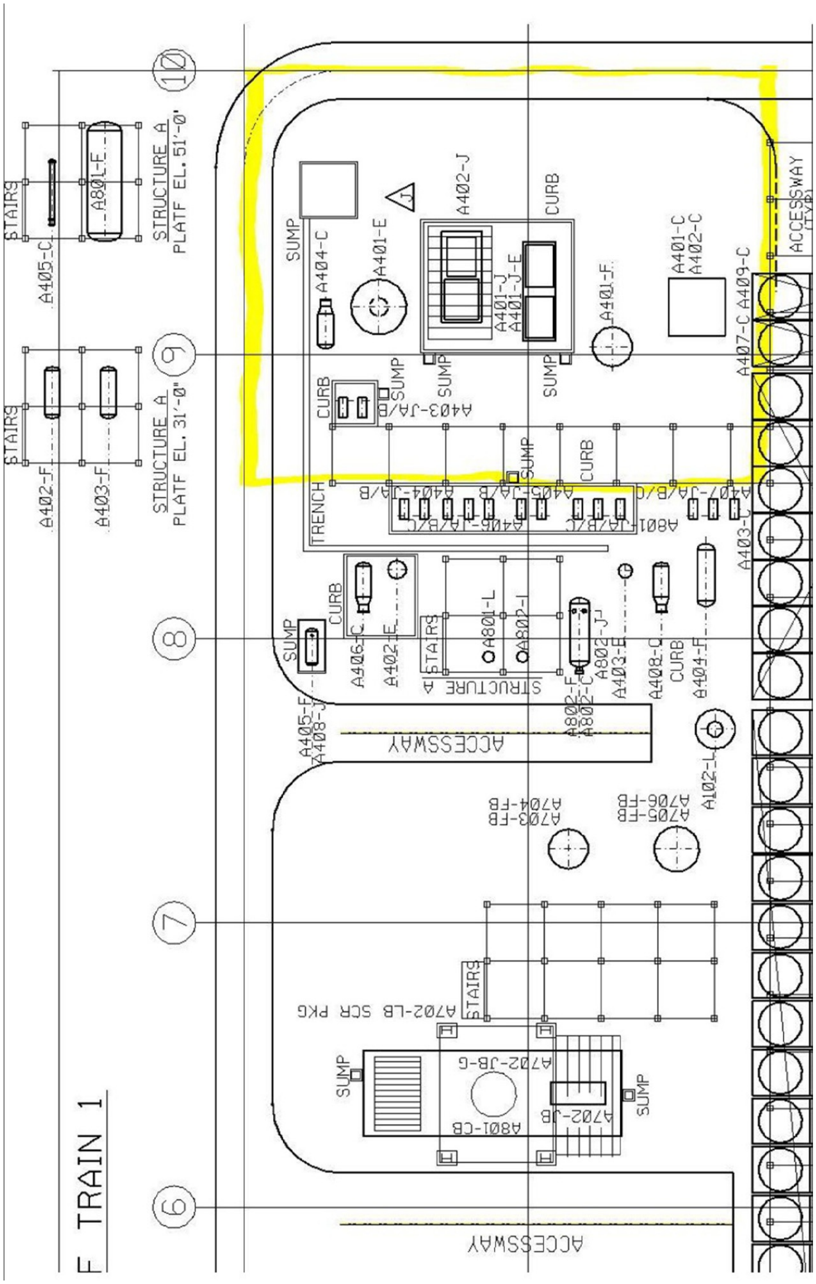


P&ID 5



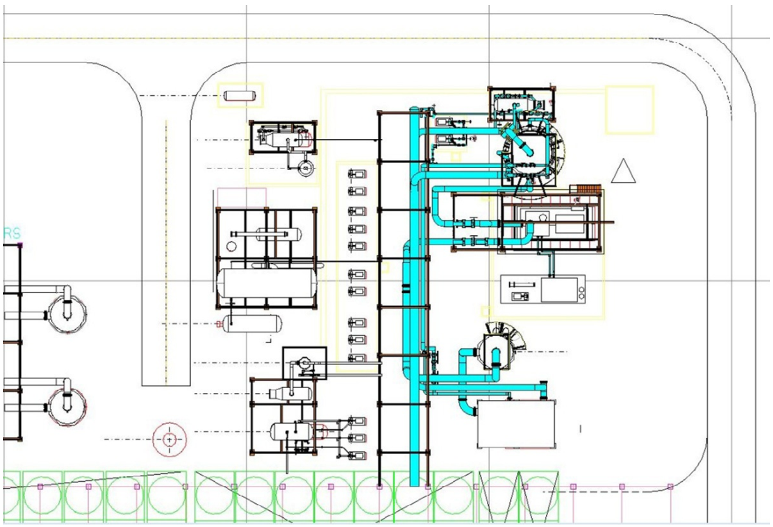
P&ID 6

UNIT PLOT PLAN

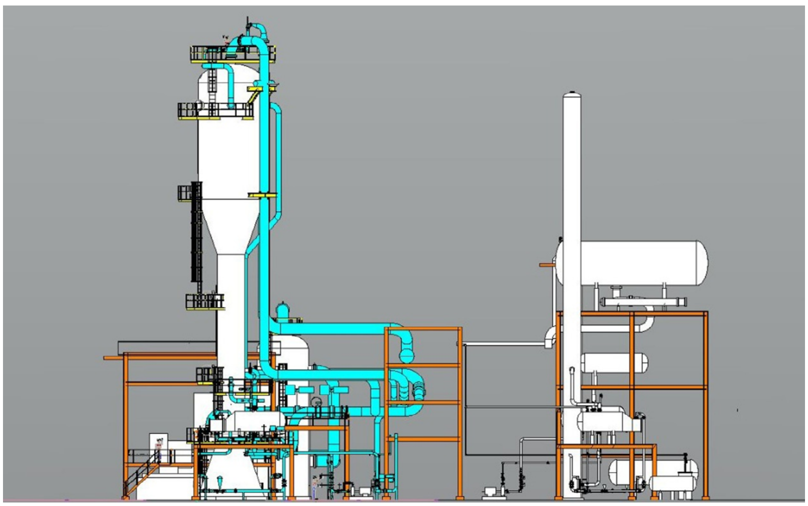


The area bounded by the yellow line (above) indicates the equipment shown in the six P&IDs, showing the layout and location of the equipment based on the flow sequence.

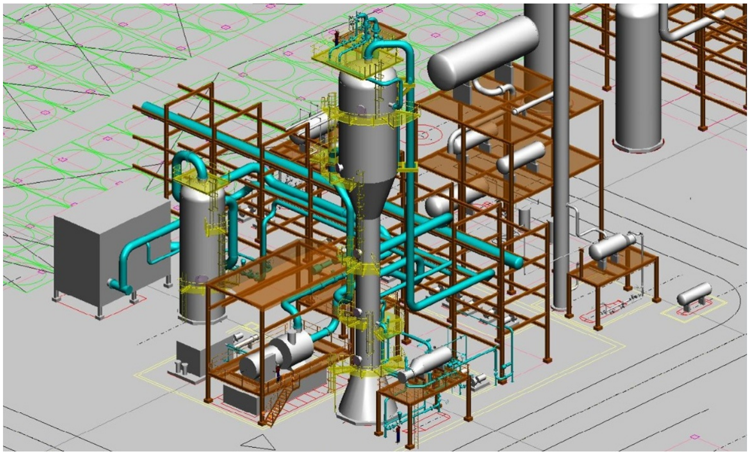
The plan (below) is the orthogen drawing cut from the smart plant 3D model, showing the major large bore and critical lines (highlighted in blue).



PLAN



SECTION



Smart Plant 3D Model View

Let us follow the typical sequence of events:

The P&ID's that show the major large bore lines and critical lines (those that would influence the spacing of equipment due to size or thermal expansion or contraction) will be prepared.

From this the development of the equipment layout plans and consequently the overall plot plan will be developed.

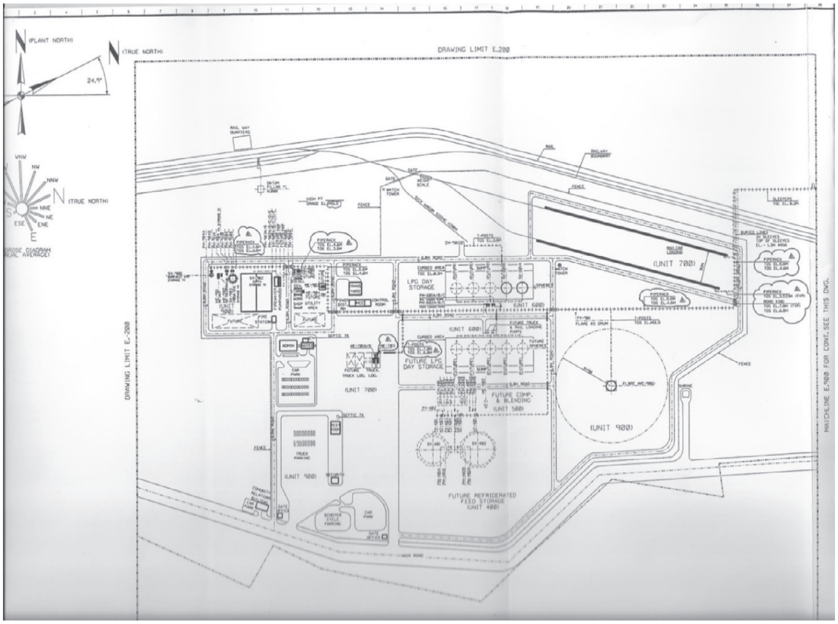
The 3D model then has the equipment built based on preliminary vendor information, and located in the model, based on the equipment layout plans.

The large bore piping and critical lines will then be run in the model and interconnected between equipment, stress analysis will be prepared, and the results will influence the layout and thus final location of the equipment.

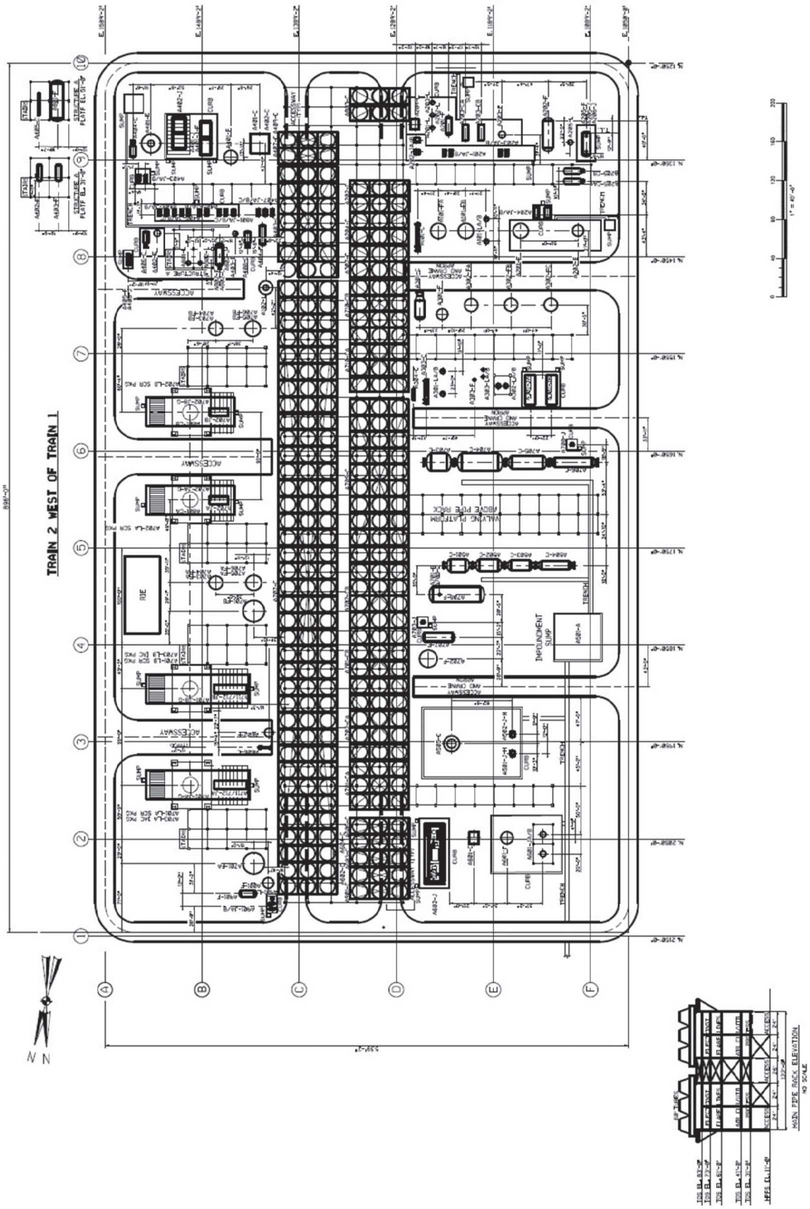
Once the equipment is located, all access roads and egress ways as well as equipment drop zones and laydown areas will be established and consequently shown on the layout drawings.

Proving the plot plan requires all the above to be established and to be correct according to all the required conditions.

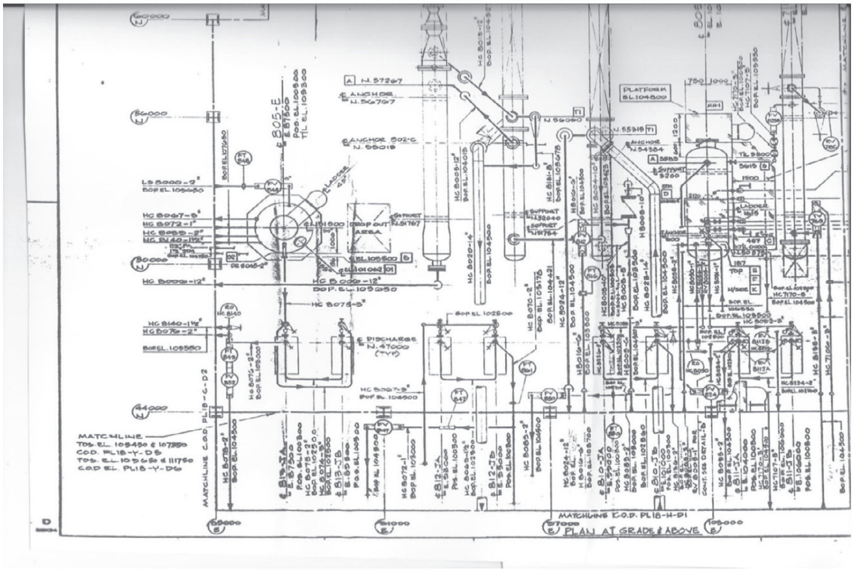
The following is a plot plan of a LPG plant; this is a 2D microstation drawing.



Plot Plan of LPG Plant



Equipment Layout Drawing showing a Typical LNG Train



Area Piping Plan (circa 1992) (manual [hand drawn]) of an Ethylene Plant

Area piping plan (c.1992) (manual [hand drawn]) of an ethylene plant

(This was how equipment layouts and piping planning drawings were produced prior to 3D computer modeling).

Some of the codes and standards that are used, but not limited to the development of the plot plan are:

ASME B31.3 Chemical Plant and Petroleum Refinery Piping
ASME B31.4 Petroleum Pipelines
ASME B 31.8 Gas Transmission Pipeline
NFPA 30 Tank Storage
NFPA 58 Liquefied Petroleum Gas Storage and Handling
NFPA 59A Liquefied Natural Gas Storage and Handling
OSHA 1910—24 Fixed Stairs
OSHA 1910—27 Fixed Ladders

The following is a check list for the checking of all items that must be included on a Plot Plan.

Required distance of new process unit from existing facility
Review equipment spacing requirements per company/client standards
Review input from site survey and topographic map
Review input from electrical area classification drawings
Review Hazard clearances from any existing facility
Coordinate grid system
True North as related to Plant North
Prevailing wind direction
Finished grade elevation and relation to existing and actual grade elevations
Location and extent of existing and new fencing
Ditches, paving, dikes, and curbed areas
Existing and new roads from the grading drawing
Pipe rack locations and steel structures
Item numbers of all equipment per the equipment list and the P&IDs
Provisions for any future expansions shown (dashed)
Locations and correct sizes of any new building shown
Equipment drawn with sizes from the equipment list and P&IDS
Plot plan matches the equipment location
Scale shown
Drawing is to scale

Appendix
Recommended equipment spacing charts

Offsite equipment spacing*

This table does not account for vapor cloud explosions, customer safety and property protection, environmental or flare vent/stack dispersal requirements.

Numbers are in ft.
A - Engineering/safety decision must be made

* Includes control rooms

	Blowdown Facilities (Drums, Pumps, Stacks)	Fired Boilers	Bldg. High Occupancy (More than 15 persons)	Bldg. Low Occupancy (15 persons of fewer)	Buildings Utility	Cooling Tower	Electrical Overhead Pole Lines	Electrical Main Substations	Electrical Control and Distribution Centers	Fire Stations, Fire Pumps	Flare Stacks	Highways, Roads & Public Areas	Loading and/or Unloading Racks	Natural Gas Metering Stations (Main Plt.)	Pipeways (Major)	Pumps (Flammable)	Pumps (NonFlammable)	Railroads (Main Lines-R/W)	Railroads (Spurs-Center Line)	Oil-Water Separators (API-CPI)	Sewer Mains (Flammable)	Plant Roads (Edge)	Property Lines (Other than roads & railroads)	Pressure Storage Vessels, 500,000 gal. or less	Spheres and Spheroids (over 500,000 gal.)	Fixed Roof Crude Oil Tanks (No Floater)	NFPA Class III Liquid Storage	Atmospheric, Low & Inter. Vapor Press. Storage	Process Units
Blowdown Facilities (Drums, Pumps, Stacks)	A	100	200	100	100	50	50	100	50	200		200	100	50	20	50	25	200	50	100	25	15	200	200	200	200	NFPA	200	100
Fired Boilers		A	200	100	A	100	50	100	25	100		100	200	100	20	50	5	100	25	200	50	15	100	200	300	200	NFPA	200	100
Bldg. High Occupancy (>15 persons)*			A	20	150	100	100	50	0	50		100	200	200	100	50	0	150	40	200	50	50	100	200	300	200	NFPA	A	200
Bldg. Low Occupancy (<=15 persons)*				A	0	100	50	25	0	50		50	100	100	20	50	0	25	A	100	25	30	25	150	200	200	NFPA	200	100
Buildings Utility					A	100	20	0	0	50		50	150	100	20	50	0	0	A	150	20	15	25	150	250	200	NFPA	200	50
Cooling Tower						A	100	100	20	100		100	100	100	25	50	A	100	35	100	20	25	25	50	100	200	NFPA	200	50
Electrical Overhead Pole Lines							A	A	A	25		20	50	25	0	5	5	25	A	50	20	4	25	25	25	25 min.	25 min.	25 min.	10
Electrical Main Substations								A	A	50		0	100	100	20	100	5	25	A	100	20	15	0	100	200	200	NFPA	200	100
Electrical Control and Distribution Centers									A	A		0	50	100	0	25	5	0	A	50	20	15	A	50	100	A	NFPA	A	50
Fire Stations, Fire Pumps										A	▼	50	200	100	20	100	0	50	50	200	20	40	25	200	300	250	200	250	200
Flare Stacks											A	◀																	
Highways, Roads & Public Areas												A	100	100	0	100	5	A	A	100	10	A	A	200	300	200	NFPA	200	100
Loading and/or Unloading Racks													A	100	20	100	5	200	A	100	10	20	100	100	100	200	NFPA	150	200
Natural Gas Metering Stations (Main Plt.)														10	10	50	10	25	25	100	10	15	25	100	100	A	NFPA	A	100
Pipeways (Major)															A	5	0	0	A	20	A	3	25	25	50	10	NFPA	10	15
Pumps (Flammable)																3	3	100	15	10	10	10	100	25	25	A	NFPA	A	A
Pumps (NonFlammable)																	3	50	A	5	10	10	50	25	25	A	NFPA	A	A
Railroads (Main Lines-R/W)																		N/A	A	100	10	10	N/A	200	200	200	NFPA	200	100
Railroads (Spurs-Center Line)																			A	100	10	A	A	100	100	A	A	A	A
Oil-Water Separators (API-CPI)																				25	10	15	100	200	200	200	100	200	200
Sewer Mains (Flammable)																					A	A	10	25	50	A	A	A	20
Plant Roads (Edge)																						A	A	A	A	A	A	A	15
Property Lines (Other than roads & railroads)																							N/A	A	200	A	A	A	100
Pressure Storage Vessels, 500,000 gal. or less																								A	A	A	A	A	200
Spheres and Spheroids (Over 500,000 gal.)																									A	100	100	100	200
Fixed Roof Crude Oil Tanks (No Floater)																										A	A	A	200
NFPA Class III Liquid Storage																											A	A	A
Atmospheric, Low & Inter. Vapor Press. Storage																												A	150
Process Units																													50

PIP recommended equipment spacing charts

PLOT PLAN

The **plot plan** is basically an arrangement drawing that shows the equipment and supporting facilities (pipe racks, structures, buildings, roads) that are required for the process facility within a battery limit area, which will be designed for independent operation and shutdown.

All equipment and components will be shown on the plot plan and identified by letters and numbers as per the company nomenclature standards.

The plot plan is drawn to scale, and a benchmark will be located on the plan, which is the datum point of the plot, which shows elevation and plant coordinates. All equipment will be located and elevated in relation to this benchmark.

The plot plan is used as the basis to produce equipment arrangement studies, and produce piping line shoots that will be used to estimate piping materials and quantities.

The Plot plan is also used to develop:

Grading and drainage plans, holding ponds, diked areas, foundation, and structural design produced by the Civil–Structural Engineering Department to enable bulk material estimates to be produced.

Area classification drawings that locate switchgear, substations, motor control centers, that enable cable routing to be determined and thus estimation of bulk materials for the electrical department.

Location of analyzer houses, cable trays, main control house/building, to enable the instrumentation department estimate bulk materials.

The plot plan is also used by the process department to facilitate hydraulic design, line sizing, and utility block flow diagrams.

Orderly scheduling of engineering activities is obtained by the scheduling department from the plot plan.

The plot plan is used by construction to schedule the erection sequence of all plant equipment. This includes rigging studies for large lifts, constructability reviews, location of lay down areas, and any marshaling activities required.

The plot plan is also to estimate the overall cost of the plant, and is also used by the client for safety, operator, and maintenance reviews, and to develop an “As Built” record of the plant arrangement.

3.6 HAZARDOUS AREA CLASSIFICATION

Classification:

A hazardous area classification must be complete to ensure that those ignition sources, such as fired heaters, combustion engines, and flares are located at an adequate distance away from potential sources of flammable substances.

Operability:

Access ways for operations and maintenance shall be a minimum of 3 m and unrestricted.

Maintenance access shall be provided to allow for dismantling of equipment. For example, access is required to pull out reciprocating compressor rods and heat exchanger bundles.

Layout review:

On completion of the draft facility plot plans and hazardous area classification drawings, a layout review shall be carried out with representatives from client operations, and the engineering design team and the project engineer.

Low-pressure process module:

Low-pressure (LP) module spacing applies to facilities which have a maximum operating pressure of 1900 kPa (g) and are hence considered "low risk," that is, manifolds, bulk separation, and crude stabilization.

High-pressure process module:

High-pressure (HP) module spacing applies to facilities whose operating pressures exceed 1900 kPa(g) and are hence considered "high risk," that is, gas lift/export compressors and gas treatment facilities.

Transfer operation:

Transfer operations typically represent road tanker loading/unloading of liquid hydrocarbons, that is, diesel, crude, and process drains vessel contents.

Storage:

Spacing's are specified on the basis of limiting damage to other facilities as a result of a tank fire (contained within the bund wall) and vice versa.

Pipe racks and tracks:

Spacing applies provided the pipes in the tracks are related to the plant concerned. These distances are not relevant to pipe racks/tracks to and from the modules or equipment concerned.

Plant inlet/outlet ESD valves:

Distances apply to main plant inlet/outlet emergency shutdown (ESD) valves

Furnaces and heaters:

Furnaces and heaters present a constant source of ignition to any hydrocarbon releases; therefore, their location must be carefully selected. The preferred location is on the upwind side of a plant near the battery limit.

Flares:

The layout and spacing of flares shall be designed in accordance with "Pressure Relief, Emergency Depressurings, Flare, and Vent Systems"

Fences:

A fence shall surround all PDO plants. Nonhazardous areas shall extend beyond the fence.

PDO wellhead locations are normally not fenced, with the following exceptions:

- Wellheads visible from main public roads or Government "black top" roads.
- H2S wells located in normally sweet fields.
- Free flowing wells with a Flowing Tubing Head Pressure > 1500 kPa(g)

Control rooms:

The control building shall be designed with a certain resistance against explosions, depending on the level of risk. The risk level in turn depends on the manning level and the distance from the process equipment.

For unmanned control rooms (visited less than 1 hour per day) that satisfy the minimum spacing requirements, no special explosion resistance measures are required.

For manned control rooms (visited more than 1 hour per day) the room shall be able to withstand the overpressure loads predicted by the PDO approved software.

Roads:

Roads, not for maintenance access, within a fenced site shall be at least 15 m from process plant equipment (30 m from LPG facilities).

Public roads (not access roads) shall be at least 15 m from the facility fence, 80 m from wellheads and 15 m from overhead power lines.

Compressors:

Equipment associated with a compressor such as fin fan coolers, knock out drums, etc. may be located in the compressor area and need not comply with spacing requirements provided they do not restrict access for firefighting and maintenance.

Owing to the excessive heat transfer surface of fin fan coolers and the types of metals used in those surfaces, cooler bundles are highly vulnerable to damage within a few minutes under fire exposure. Fin fans should preferably be located on the opposite side of the module, away from fire sources, to avoid ignition in the event of fin fan tube leakage.

Access to compressors for firefighting purposes must be maintained on at least two side of the installation.

Gas turbine or gas engine-driven compressors shall be located not closer than 20 m from parallel units, as the drivers constitute a source of ignition. A minimum of 10 m is recommended for electrically driven units.

Pumps:

Gas turbine or gas-driven pumps shall be located not closer than 20 m from parallel units. As the drivers constitute a source of ignition. The recommended distance for electrically driven units is 10 m.

Pumps shall be isolated from the gas turbine drivers by a firewall, which is normally an integral part of the turbine enclosure.

Firewater pumps shall be located at least 20 m away from oil storage tanks and 25 m from hydrocarbon containing equipment.

Pumps may be located at a minimum distance of 3 m from the bund wall for maintenance access reasons, provided the pump is electric motor driven and is considered an integral part of the tank module.

Multiple furnace/heaters:

For multiple furnace/heaters that are shut down together for maintenance, only nominal spacing for access is required (5 m). Furnace/heaters shutdown individually require a spacing of 15 m if the coil inlet design pressure is less than 1900 kPa(g),and a spacing of 25 m if the coil design pressure exceeds 1900 kPa(g).

Pipe racks locate at 5 m from furnaces/heaters shall not contain any valves except those related to the furnace/heater concerned.

Hazard identification:

HAZard identification is a means of identifying occupational **HSE** hazards and threats at the earliest stage of the project. Three types of area have been defined:

Process facilities: This is an area within a boundary fence of any hydrocarbon processing facility that includes Gathering and Pumping Stations, Terminals and other fenced hydrocarbon storage and processing areas.

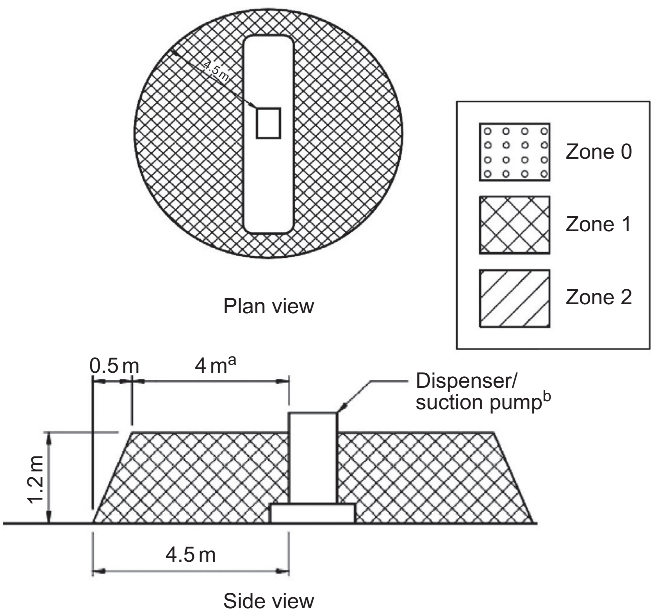
Hydrocarbon areas: These are areas outside the boundaries of process facilities where hydrocarbons are or have been present. These include areas outside process facilities, but within 50 m of the boundary fence. Areas within 50 m of a well site or exposed section of flow line or pipeline which has flanged joints, and areas within 100 m of a drilling rig for work by nondrilling personnel.

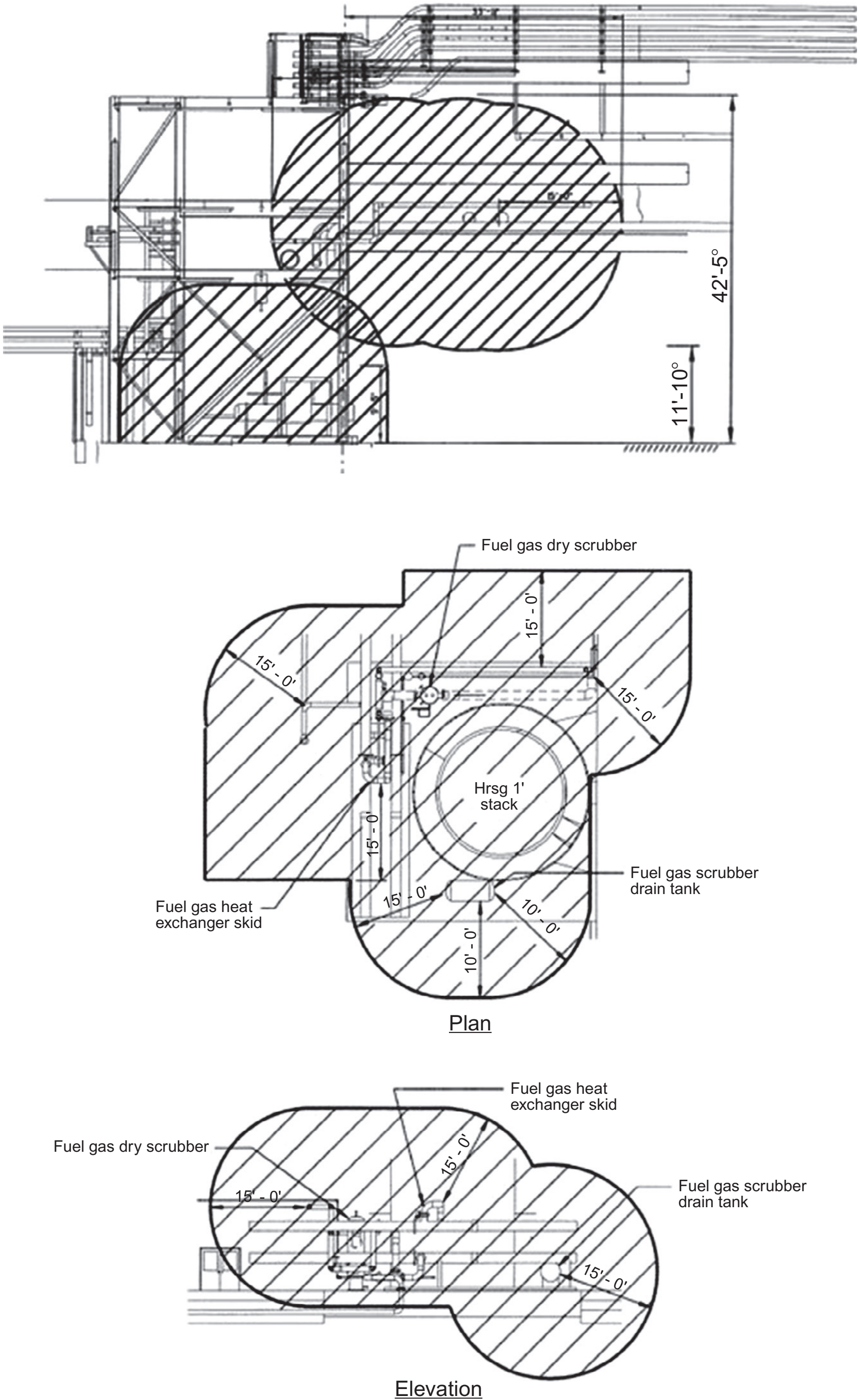
Nonhydrocarbon areas: These are areas where hydrocarbons have never been present, they include areas of land outside process facilities and hydrocarbon areas, including construction sites for new facilities until hydrocarbons are first introduced, and also the areas surrounding fully welded pipelines, as well as electrical switching stations and on power distribution systems, administration, recreation, and accommodation buildings, laboratories and medical facilities.

Classification of hazardous area: Areas such as process facilities and hydrocarbon areas are classified, and they depend on the presence of hydrocarbons in the atmosphere. Hydrocarbons get mixed with air and this creates highly explosive mixtures, which are potential hazards for creation of fire or explosion.

- Oil and gas facilities contain potentially hazardous areas, explosive gases can exist in varying frequencies at different areas in the facility.
- Special care has to be taken in equipment selection for these areas.
- Process facilities are divided into the following zones according to the potential hazard.
  - ZONE 0—Hydrocarbon present 1000 hours to always in 365 days.
  - ZONE 1—Hydrocarbon present 10–1000 hours in 365 days.
  - ZONE 2—Hydrocarbon present up to 10 hours in 365 days.

All other areas not shown as ZONED are considered safe areas.





Hazardous area classification drawings

Plant/piping design safety check list:

When reviewing plot plans and piping arrangement, drawings checks need to be performed to ascertain if all safety aspects have been incorporated. The following list outlines the major checks to be performed.

Above ground:

- Have relief valve inlet and outline configurations been reviewed by process systems.
- Do atmospheric relief valve discharges meet the criteria as outlined in API specifications?
- Are block valves @ relief valves car sealed (CSO) or locked open (LO)?
- Does the piping general arrangement throughout the plant allow for safe egress for plant personnel?
- Is the remote snuffing system manifold at fired heaters at least 15 m (50 ft) from the radiant section or source of ignition?
- Has adequate provision been made to blind off vessel nozzles?
- Have all applicable piping systems been protected with personnel protection insulation?
- Do plant roads provide adequate access for mobile firefighting equipment?
- Have safety eye-wash and showers been provided to meet client and local regulations?
- Will operator egress from elevated floors and platforms in an emergency always be in a downward direction?
- Do all dead-end platforms or excessively long platforms meet OSHA requirements?
- Where pumps are located under hydrocarbon bearing air coolers is the potential spilled liquid below its auto ignition temperature?
- Is fired equipment located upwind of potential sources of ignition?
- Do storage tank locations meet all applicable NFPA, client, or local government regulations?
- Does the general equipment spacing meet client and PIP specifications?
- Is adequate protection provided for all major firefighting components in freezing climates?
- Are storage tanks and dikes located at a lower elevation than adjacent process equipment wherever possible?
- Are flare radiation zones sterile areas? Has the client approved the location of equipment in this area?
- Have any piping material substitutions been approved by the specifications engineer, the metallurgist, the pipe stress engineer, and chief engineer?

Underground systems:

- Has the drainage system been designed to prohibit the spread of fire throughout the plant?
- Are manways properly vented to a safe located area?

- Have the double containment regulations been satisfied?
- Is the equipment bearing hazardous materials (i.e., caustic) curbed and drained to a safe location?
- Is every piece of equipment in a process unit covered by at least one permanent fire monitor?
- Is the firewater loop fed by at least two sources of supply?
- Are hazardous material drains piped to a closed system?

3.7 SPACING WITHIN PROCESS AND UTILITY PLANTS

Item	Support Reference	Open Installation		Enclosed Installation	
		ft	mm	ft	mm
Process units and utility plants:					
Grade paving, floors	High point Low point	100′ 99′-6″	100,000 99,850	100′-6″ 100′-2″	100,150 100,050
Vertical vessels	Bottom of base	100′-6″	100,150	101′	100,300
	Ring or legs (POS)				
Tankage	Bottom (POS)	101′	100,300	101′-6″	100,450
Horizontal vessels	Bottom of saddles or CL elevation	As required for NPSH or for operation and maintenance			
Pumps, blowers, packaged units	Bottom of baseplate	100′-6″	100,150	101′	100,300
Independent lubricated compressors	Bottom of baseplate CL of shaft	As required for lube oil return piping or surface condensers			
Motor—driven reciprocating compressors	Bottom of baseplate CL of shaft	As required for clearance at pulsation bottles and piping			
Furnaces, wall or roof fired	Bottom of floor plate (POS)	104′	101,200	NA	NA
Furnaces, floor fired	Bottom of floor plate (POS)	108′	102,400	NA	NA

Continued

Item	**Support Reference**	**Open Installation**		**Enclosed Installation**	
		ft	**mm**	**ft**	**mm**
Vertical reboilers	Bottom of lugs (POS)	As required to suit structure or related tower			
Pipe racks	Top of steel (TOS)	As required to suit clearances for operation and maintenance access.			
Offsites:					
Grade paving, floors	High point	9″	230	1′-3″	380
	Low point	3″	75	9″	230
Vertical vessels	Bottom of base	1′-3″	380	1′-9″	530
	Ring or legs (POS)				
Storage tanks	Top of berm or bottom of tank (POS)	1′-0″	300	NA	NA
Horizontal vessels	Bottom of saddles of CL elevation	As required for NPSH or for operation and maintenance			
Pumps, blowers, packaged units	Bottom of baseplate	1′-3″	380	1′-9″	530
Cooling towers, clarifiers clear wells	NA	As required		NA	NA
Grade pipe sleepers	Top of steel (TOS)	1′-0″	300	NA	NA

Item	**Description**	**Dimensions**	
		ft	**mm**
Roads, paving and railroads—sizing:			
Main plant roads	Width	24′	7300
	Headroom	22′	6700
	Inside turning radius	22′	6700

Continued

Item	Description	Dimensions	
		ft	mm
Secondary plant roads	Width	16′	4800
	Headroom	14′	4300
	Inside turning radius	10′	3000
	Width	10′	3000
Minor access roads	Headroom	11′	3400
	Inside turning radius	8′	2450
Paving	Distance from outside edge of equipment to edge of paving	4′	1200
Railroads	Headroom over railroads, from top of rail	22′	6700
	Headroom over dead ends and sidings, from the top of rail	12′	3600
	Clearance from track CL to obstruction	8′-6″	2600
	Centerline distance between parallel tracks	13′	4000
	Distance between CL of track and parallel above ground and underground piping	23′	7000
	Cover for underground piping within 23 ft (7000 mm) of track centerline	3′	900
Platforms, ladders, stairs—sizing:			
Platforms	Headroom	7′	2100
	Width of walkways (grade or elevated)	3′	900
	Maximum variance between platforms without an intermediate step	9″	230
	Width at vertical vessels	3′	900
	Distance between inside radius and inside of platform on vertical vessels	10″	250
	Maximum distance of platform or grade below centerline of maintenance access	5′	1500
	Maximum length of dead ends	20′	6000
Ladders	Width of ladders	1′-6″	450
	Diameter of cage	2′-4″	710
	Extension at step-off platforms	4′	1200
	Distance of bottom hoop from grade or platform	8′	2400
	Distance between inside radius of vertical vessels to CL of ladder rung	1′-2″	350
	Maximum vertical rise of uninterrupted ladder run	30′	9150
	Maximum slope from vertical axis	15 degrees	

Continued

Item	Description	Dimensions	
		ft	mm
	Toe clearance	8″	200
Stairs	Width (back to back of stringer)	2′-6″	750
	Maximum vertical one-flight rise	18′	5500
	Maximum angle	50 degrees	
	Headroom	7′	2100
	Width of landing	3′	900

Item	Activity	Handling Device
Maintenance requirements:		
Vertical vessels	Maintenance access cover removal	Maintenance access davit
	Relief and control valve removal	Top head davit
	Catalyst loading and unloading	Mobile crane
	Vessel internal removal	Top head davit or mobile crane
Exchangers	Cover removal (horizontal)	Hoist trestle with load up to 2000 lbs (900 kg) or mobile crane
	Bottom covers removal (vertical)	Hitch points
	Top cover removal (vertical)	Mobile crane
	Bundle removal (horizontal)	Mobile crane and extractor
	Bundle removal (vertical)	Mobile crane
	Rodding	Manual
	Air cooler tube removal	Mobile crane
	Plate removal (plate exchanger)	Manual
Pumps and compressors	Motor or largest component removal (housed)	Trolley beam or traveling crane
	Motor or largest component removal (open installation)	Mobile crane or hoist trestle with load up to 2000 lb (900 kg)
	Vertical pumps	Mobile crane
Furnaces	Coil removal	Mobile crane
Miscellaneous	Filter removal	Manual or hoist trestle
	Strainer removal	Manual
	Relief valves, 4–6 in. and larger	Davits, hitch points, or crane
	Blinds, blanks, figure-8s, and valves, More than 300 lb (135 kg)	Hoist trestle
	Small components, 300 lb (135 kg) and less	Manual or hoist trestle

Item	Platform or Grade	Fixed Ladder
Operator access to controls:		
Maintenance access	Yes	No
Level controls	Yes	No
Motor operated valves	Yes	No
Sample connections	Yes	No
Blinds and figure—8s	Yes	No
Observation doors	Yes	No
Relief valves	Yes	No
Control valves	Yes	No
Battery limit valves	Yes	No
Valves, 3 in. and larger	Yes	No
Hand holes	Yes	Yes
Valves, smaller than 3 in.	Yes	Yes
Level gauges	Yes	Yes
Pressure instruments	Yes	Yes
Temperature instruments	Yes	Yes
Vessel nozzles	No	No
Check valves	No	No
Header block valves	No	No
Orifice flanges	No	No

Underground facilities:

Underground facilities can affect the positioning of equipment.

Foundations for equipment are either piled or spread footings, and this is dependent on the soil conditions.

Spread footings require more space than piles; therefore, equipment must be located with enough space between the equipment.

In certain cases, equipment can be located on a common foundation.

If the project specifications allow for instrument and electrical cabling to be located below ground adequate space must be allowed between the cabling and equipment.

Most process units have underground oily water sewers, storm sewers and firewater and chemical drainage systems. All these require plot space and must be accounted for.

Climate conditions:

Weather conditions can influence equipment location.

In severely cold climates, equipment should be housed by encasing the whole unit.

Groups of equipment such as pumps can be housed in a common enclosure or building.

Consideration must always be given to locate equipment in process sequence.

Wind can also influence the location of equipment such as furnaces, compressors, control houses, cooling towers, and stacks.

Furnaces and other fired equipment must be located so as to not allow any flammable vapors from stacks to drift over the equipment.

Pipe racks:

Generally, most plants are furnished with a central pipe rack.

This acts as the main artery of the unit, and supports the process, feed, product and utility piping, as well as the instrument and electrical cables.

Pipe racks are made of structural steel or concrete, and are either single or multi-level, the dimensions of which will be to suit the unit the rack is serving.

Pipe racks bays are usually spaced at 20 ft (6 m) centers.

Pipe rack widths are based on the number of pipes and cabling to be accommodated. Allowance for future expansion must be taken into account and this is usually 25%.

CHAPTER

Piping and equipment basis for selection

4

4.1 BASES FOR THE SELECTION

Process engineering will first develop a process flow diagram (PFD) which shows the required equipment and interconnecting process flows. At a later stage after the basis of design is established a process and instrumentation diagram (P&ID) will be developed. From the PFD a **basis of design** will be established and from this an **equipment basis of design** is established. A **process simulation** will be conducted by process engineers for all phases of the design from preliminary design to basic design through to front end design and finally to detail design. The process simulation enables the production of heat and material balance and provides the basic process parameters for equipment sizing and specification. This simulation consists of the following:

- thermodynamic package selection
- physical properties and equilibrium ratio data
- definitions of operating conditions
- flash calculations
- pressure vessel
- vessel selection: vertical or horizontal
- calculation procedure for vertical vapor-liquid separators
- calculation procedure for horizontal two-phase and three-phase separators
- boot calculations, vessel internals
- fractionators and absorbers types

Product specifications can be developed from this basis and simulation.

EQUIPMENT SIZING

The equipment sizing is determined on the basis of design and this information is then provided on process data sheets by the process engineering department.

The process engineering will then produce a process data sheet from the process simulation information for each piece of equipment which will state all the required information that the mechanical engineer will need to choose and size the equipment.

From this data, for example, the static vessel engineer will be able to determine the volume of vessel required, the type of vessel (horizontal or vertical vessel), from which the diameter versus the length of the vessel can be calculated based on plant size restrictions, whether vessel internals are required or not depends on the process,

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00004-7

flammability, and hazardous materials to be stored in the vessel, temperature (does the vessel need insulation), pressures (determines wall thickness and reinforcing requirements), and corrosion allowances (to be added to wall thickness) are required for the design of the vessel.

All calculations for the design of pressure vessels will be in accordance with ASME BPVC Sec VIII Div. 1 or Div. 2 and for storage tanks API 620, 650, etc.

Likewise a rotating machinery engineer will have enough information from the process data sheet, such as flow rates, density, temperatures, and pressures irrespective of whether it is a two-phase flow or not, etc., to enable the choice of and type, material, capacity, function, design, of the pump, compressor, air fans, etc.

- All designs for rotating equipment shall conform to the related API standard.
- Design of pumps shall conform to API STD 610, 682, etc.
- Design of compressors shall conform to API STD 617, 618, etc.
- Design for shell and tube exchangers shall conform to API STD 660, etc.
- Design for air cooled exchangers shall conform to API STD 661, etc.
- Design for plate heat exchangers shall conform to API STD 662, etc.
- Design for fired heaters shall conform to API STD 560, 553, 535, etc.

4.2 PRESSURE CLASS

Process industry piping systems are designed in accordance with one of the ASME Codes for Pressure Piping, B31, which define the design and construction requirements of several kinds of piping systems: B31.1, Power Piping and B31.3, Chemical and Petroleum Refinery Piping.

The B31 codes incorporate reference standards for valves, fittings, and components, many of which include temperature and pressure ratings. These components may be used within these ratings, but not in excess of the general limits of the code.

Pipe class refers to the "maximum internal pressure a pipe can safely sustain" however the pipe itself may not (and in most cases, doesn't) fix the maximum safe pressure allowable on the ENTIRE piping system involved. In most cases, the flanges are the weakest point, and this should be the guiding design factor with regards to allowable pressure in that specific piping class.

A Pipe Class Specification is a document which contains the definition of pipe, valves, and all related fittings and components that should be used under a specific pressure and temperature condition including the service that the spec can be used with.

Piping class ratings based on ASME B16.5 and corresponding PN (pression nominal*) are as follows:

Flange class:	150:	300:	400:	600:	900:	1500:	2500
Flange pressure nominal, PN:	20:	50:	68:	100:	150:	250:	420

- Pression nominal is the French equivalent of pressure nominal.
- Pression nominal is the rating designator followed by a designation number indicating the approximate pressure rating in *bars*.
  - 1 bar = 1×10^5 Pa (N/m^2) = 0.1 N/mm^2 = 10,197 kPa/m^2 = 10.20 m H_2O = 0.98692 atm = 14.5038 psi ($lb/in.^2$)

PN ratings do not provide a proportional relationship between different PN numbers, whereas class numbers do. Class numbers are therefore recommended before PN ratings.

Maximum Allowable Nonshock Pressure (psig)							
Temperature (°F)	Pressure Class (lb.)						
	150	300	400	600	900	1500	2500
	Hydrostatic Test Pressure (psig)						
	450	1125	1500	2225	3350	5575	9275
−20 to 100	290	750	1000	1500	2250	3750	6250
200	260	750	1000	1500	2250	3750	6250
300	230	730	970	1455	2185	3640	6070
400	200	705	940	1405	2110	3520	5865
500	170	665	885	1330	1995	3325	5540
600	140	605	805	1210	1815	3025	5040
650	125	590	785	1175	1765	2940	4905
700	110	555	740	1110	1665	2775	4630
750	95	505	675	1015	1520	2535	4230
800	80	410	550	825	1235	2055	3430
850	65	320	425	640	955	1595	2655
900	50	225	295	445	670	1115	1855
950	35	135	185	275	410	685	1145
1000	20	85	115	170	255	430	715

PRESSURE CLASS

Higher pressures and API flanges

ASME rates the pressure of a class based on the materials used for the construction and the design temperature. API specifies allowable materials and gives it a specific pressure rating. The difference between ASME/ANSI and API flanges is the fabrication material and a higher rated API operating pressure. ASME/ANSI flanges are commonly used in industrial process systems handling water, steam, air, and gas.

API flanges are manufactured for high-strength operating refinery systems with products such as oil and explosive gases.

There are three common types of API flanges: API 2000, 3000, 5000, and two high-pressure series: API 10,000 and 15,000. The number of the series indicated corresponds to the maximum working pressure expressed in psi at a temperature of l00°F. This maximum working pressure is affected by temperature. The maximum working pressure of the flange will be reduced by a factor of 1.8% for each 50°F increase in temperature above 100°F to a maximum of 450°F. The following table gives the maximum working pressure as a function of temperature.

Temperature (°F)	Maximum Working Pressure in psi				
	API 2000	API 3000	API 5000	API 10000	API 15000
100	2000	3000	5000	10000	15000
150	1964	2946	4910	9820	14730
200	1928	2892	4820	9460	14460
250	1892	2838	4730	9280	14190
300	1856	2784	4640	9199	13920
350	1820	2730	4550	8929	13650
400	1784	2676	4460	8740	13380
450	1748	2622	4370	8560	13110

The flange standards API 6A and ASME/ANSI B16.5 have the same dimensions—but the API 6A flanges are rated for higher pressures as indicated below.

API Versus ASME/ANSI Flanges with Same Dimensions				
Flange	Pressure Class Rating (psi)		Nominal Size Range (Inches)	
	ASME/ANSI B16.5	API 6A	ASME/ANSI B16.5	API 6A
Weld neck	600	2000	1/2–24	$1^{13/16}$–11
	900	3000		
	1500	5000		
Blind and Threaded	600	2000		$1^{13/16}$–$21^{1/4}$
	900	3000		$1^{13/16}$–$20^{3/4}$
	1500	5000		$1^{13/16}$–11

There are two high-pressure series: API 10000 and API 15000. These pressures refer to the maximum **working** pressure ratings of the equipment. API 10000 (psi) is 690 bar, API 15000 (psi) is 1035 bar, API 10,000 and API 15,000 flanges are primarily used on wellheads, flow lines, and subsea applications.

4.3 RELIABILITY

The components, equipment, and systems are not perfect and they are not free from failures. Everything fails—in the end—the natural law of entropy expresses that the lowest energy state is a failure, nothing lasts forever without failure.

Reliability is the probability that a component, system, or process will function without failure for a specified period of time when operated correctly under specified conditions. Reliability engineering is concerned with predicting and avoiding failures. To identify reliability issues it is important to know why, how, how often, and costs of failures. Reliability issues are bound to the physics of failure mechanisms so the failure mechanisms can be mitigated. The prediction of failures is inherently a probabilistic problem where reliability analysis is a probabilistic process.

Risk assessment: Models connect money with failures in a simple equation

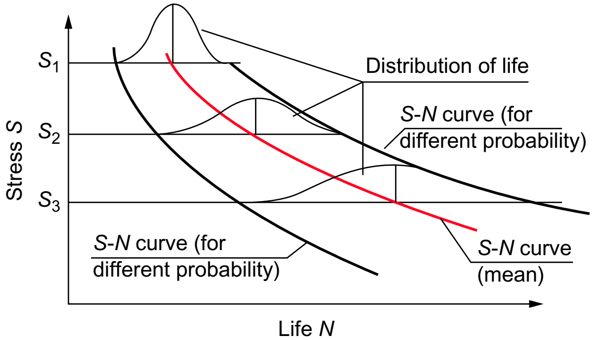
$Risk = (probability of failure during a specified time interval and under specific conditions) * ($Consequence of the failure event). $Risks always exist, and they are never zero.

- How much $Risk is affordable becomes a business issue.
- Reliability engineering versus maintenance engineering
  - Reliability engineering is concerned with the strategic task of predicting and avoiding failures.
  - Maintenance engineering is concerned with quickly restoring failures to an operable condition as a tactical task.

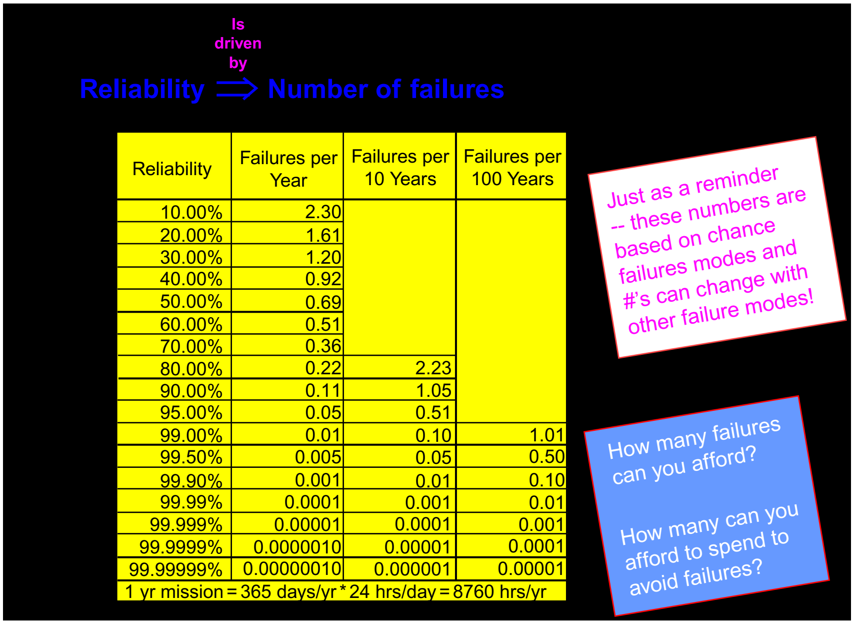
The task of a reliability engineer is to prevent failures—this is a **strategic** task and the task of a maintenance engineer is to restore quickly the failure to an **operable condition**.

Reliability is an engineering discipline for applying scientific know-how to a component, assembly, plant, or process so that it will perform its intended function, without failure, for the required time duration when installed and operated correctly in a specified environment.

Design-for-reliability (DFR) during the conceptual design stage is challenging. There are several gaps and deficiencies hindering the implementation of DFR. The first gap is due to the disconnection between the output of the conceptual design and reliability parameters needed for the reliability modeling. The second gap is between the knowledge available during the conceptual design and the information needed for reliability analysis. DFR research and implementation are primarily based on the traditional reliability stress and strength interference theory.



Stress versus life cycle graph



Reliability	Failures per Year	Failures per 10 Years	Failures per 100 Years
10.00%	2.30		
20.00%	1.61		
30.00%	1.20		
40.00%	0.92		
50.00%	0.69		
60.00%	0.51		
70.00%	0.36		
80.00%	0.22	2.23	
90.00%	0.11	1.05	
95.00%	0.05	0.51	
99.00%	0.01	0.10	1.01
99.50%	0.005	0.05	0.50
99.90%	0.001	0.01	0.10
99.99%	0.0001	0.001	0.01
99.999%	0.00001	0.0001	0.001
99.9999%	0.0000010	0.00001	0.0001
99.99999%	0.00000010	0.000001	0.00001
1 yr mission = 365 days/yr * 24 hrs/day = 8760 hrs/yr			

LIFE CYCLE COSTS

Life cycle costs (LCC) refer to all costs associated with the acquisition and ownership of a product or system over its full life (Fabrycky, 1991). The usual figure of merit is net present value (NPV). The NPV is a financial tool for evaluating economic value added. It is the difference between present value of an investment's future net cash flows and the initial investment for a given discount rate hurdle. The present values of the project for each year are summed for the NPV.

For the entire project, the life cycle cost number requires a positive NPV. Bigger positive NPVs are better.

Decisions are made in selecting equipment based on the least negative NPV. The least negative NPV is better.

LCC tasks require comparisons of alternatives: Project engineers want to minimize capital expenditures, accounting wants to maximize NPV, production wants to maximize uptime hours, maintenance engineers want to minimize repair hours, and reliability engineers want to avoid failures.

The reliability of a component or equipment is a function of, and limited to, many factors:

- materials
- strength
- corrosion
- induced stresses
- life cycle
- project costs
- adequate design for reliability
- risk assessment
- failure analysis and prevention
- fatigue
- amount of acceptable risk

Reliability of piping systems

A piping system reliability highly depends on the stresses and displacements incurred upon it. Stresses and displacements may be caused by the systems static, dynamic loadings, and also thermal effect. The system should be designed such that its stresses and displacements are least sensitive to any changes in the loadings and thermal effects. If this is achieved then the design can be said to be “Robust.”

4.4 ROBUSTNESS

Let’s now look at robustness of plant and piping systems.

What do we mean by “**robustness”?**

Robustness is the ability of a component, equipment, or material to demonstrate an acceptable quality and performance while tolerating variability in inputs. **Robustness** is not only about the correct choice of materials, but also about the quality of design, the quality of manufacture, the ability to resist corrosion, resist vibration, resist fatigue and sustained stresses, and withstand cycling (startup and shutdown in the case of equipment).

Performance and **variabilit**y are factors impacting robustness and may be managed through design and material composition.

What do we mean by a **robus**t process plant?

In simple terms, a **robust** plant is one that is **reliable.** A **robust** plant, then, is the one that does not stop unexpectedly, starts **efficiently** every time, and will withstand wide variations in conditions.

Technical safety is a key concept, which relates to the robustness of a process plant against hazards and accidents. In this context, a process plant is a system consisting of a number of components intended to deal with a hydrocarbon stream from a reservoir, pipeline, ship, rail tanker, or tanker truck.

What are the factors that would stop the plant process?

- equipment failure
- goods manufactured—procurement
- critical spares—availability
- piping and components
- required heat and cooling systems (are they adequate?)
- process controls and instrumentation

If the robustness of any of these items mentioned due to bad manufacture, incorrect materials for the process, quality control of components, etc., is nonconformant, then the robustness is impaired.

ROBUST PIPING DESIGN

Earlier in this chapter we have looked at reliability of piping systems and what is needed from a reliability point of view to obtain a robust design. By applying robust analysis techniques during the piping design phase, the system can be made more reliable as follows:

> This is achieved by the reduction in turnaround time between the piping designer's layout and the stress engineer's analysis and comments.
>
> To reduce the cycle time between the designer and the stress engineer means that the design must be good enough and need little change when it is send to the stress engineer for approval.
>
> Therefore, the design must be robust from the early stage, so that it is ready for approval when it reaches the stress engineer.

How do we achieve this?

- By having a designer who has a better understanding of stress analysis and layout techniques.
- By having a better understanding of the design codes, and materials.

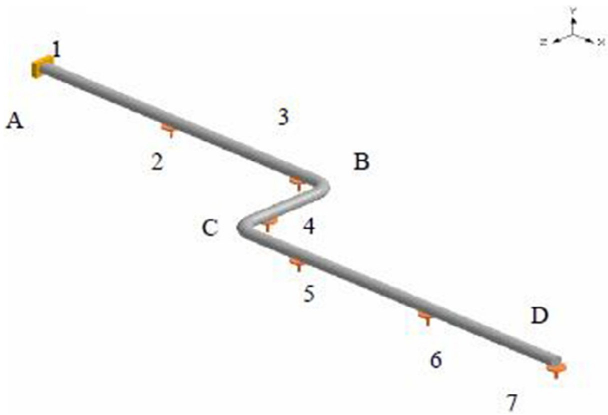
Some designs can be said to be more robust than others, however both will work. The difference between the two will be life cycle and failure risk. The robustness of a design is affected by their operational environment. A **robust** design is one that satisfies design requirements while minimizing the effects of the environmental variability on the product performance. The environmental variations may include the raw materials, manufacturing processes, operational environments; these all can lead to deviations in the performance of the system and resulting product.

Design of piping systems can be divided into three categories.

Feasible designs are ones that aspires to achieve robustness while satisfying all the design conditions.

Robust designs are ones that satisfy the best functional evaluation and analysis, thus producing the best physical structure to obtain the best design results. Therefore, a robust design is hardly affected by environmental variations.

Ideal designs are ones that satisfy all possible conditions, which in reality is often hard to achieve. It is not always possible to achieve a design that encompasses all the three of these attributes, so sometimes a compromise between the three has to be achieved. For the design shown below the designer would normally place a group of supports with a span of, in this case, 15 ft (5 m) for A53 steel. Is this a robust design? The design can be modelized as a "Z" structure, with three supports, therefore the pipe section between 3 and 5 is considered for the static loadings, weight, and two moments at each end due to the internal actions of the separation from the other parts.



Stress is a major concern during the design and analysis of a piping system, and any stress in the cross-section can be calculated using its internal moment.

For this design the maximum moments will occur at the positions of the supports. So the robustness of this design may be achieved when the stresses are insensitive to loading changes Therefore this requires that the moments are insensitive to the variations of supporting forces, which are determined by the loading.

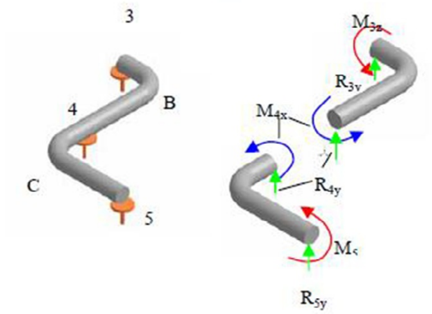
The location of support B is decided by the following calculation, where element 3-B-4 consists of 3-B and B-4 pipes. The lengths and weights are denoted as L_{3B}, L_{4B}, L_{3B} and W_{4B}, and element 4-C-5 consist of 4-C and C-5 pipes. Their lengths and weights are denoted by L_{4C}, L_{5C}, W_{4C}, and W_{5C}.

The following design represents the mechanical relationship between the structural strength, supports, and loads:

$$\sum M_x = 0, \sum M_z = 0, \sum F_z = 0$$

Thus,

$$M_{3z} = R_{3y} \cdot L_{3B} - W_{3B} \cdot L_{3B}/2$$
$$M_{4x} = R_{4y} \cdot L_{4B} - W_{4B} \cdot L_{4B}/2, \text{ or}$$
$$M_{4x} = R_{4y} \cdot L_{4C} - W_{4C} \cdot L_{4C}/2$$
$$M_{5z} = R_{5y} \cdot L_{5C} - W_{5C} \cdot L_{5C}/2$$
$$R_{3y} + R_{4y} + R_{5y} = W_{3B} + W_{4B} + W_{4C} + W_{5C}$$



The example shown above will normally be analyzed by a computer program such as Caesar II by the stress engineer, and if it has to be calculated manually many calculations other than the one shown would have to be completed.

Robust design and analysis can achieve the design goals. **Robust** design methods together with professional piping knowledge, piping codes, and engineer and designer expert experience can all be applied to produce a **robust design.**

4.5 FIRE RESISTANCE

Fire resistance is the degree of resistance of a material to fire often measured in terms of time of withstanding a standard test fire.

Fire resistant means a material's resistance to fire that for a specified time and under conditions of standard heat intensity will not fail structurally, or allow transit of heat, and will not permit the side away from the fire to become hotter than a specified temperature.

Fire resistance means the ability of buildings and structural components to perform their intended fire separating and/or load-bearing functions under fire exposure conditions. Fire-resistant structural and building components are those that are specified with fire resistance ratings based on fire resistance tests. These ratings, expressed in minutes and hours, describe the time duration for which a given building or structural component maintains specific functions when exposed to a specific simulated fire event. Various test protocols describe the procedures to evaluate the performance of doors, windows, walls, floors, beams, columns, etc. The term "fire proof" is a misnomer in that nothing is fire proof. All construction materials, structural components, and piping systems have limits beyond which they will be irreparably damaged by fire.

So when we say something is **fire resistant,** we mean that the material is very hard to catch fire and will not fail. The fire will not get past a certain temperature for a certain amount of time aka "fire resistant."

Fire retardant is a substance that reduces flammability of fuels or delays their combustion. This includes chemical agents, but may also include substances that work by physical action, such as cooling the fuels, such as firefighting foams and fire-retardant gels. Fire retardants may also be coatings applied to an object; fire retardants are commonly used in firefighting.

Fire proof: A component is called fireproof when that component is able to withstand fire or great heat. Remember nothing is totally fire proof, each material has a certain resistance to heat for a certain period of time, and each material withstands heat for differing periods of time.

- The time a component can withstand heat, can be increased by adding **fire proofing** on the material.
- Fire protection:
  - there are two types of fire protection
  - passive fire protection
  - active fire protection
- Passive fire protection
  - fireproofing and fireproofing requirements
  - resistance against fire
  - high fire-potential equipment
  - fire protection zone
  - fireproofing for supports, equipment, and pipe racks
  - fireproofing for electrical and instrumentation and valves
- Active fire protection
  - fire water supply systems
  - fire water supply
  - fire water pumps
  - fire water distribution systems
  - fire water ring mains
  - hydrants
  - riser stacks
  - fire foam and water monitors
  - inert gas systems and steam systems
- Passive fire protection
  - Fireproofing requirements: Objectives of fireproofing are as follows:
  - Provide a temporary protection to steel structures from the escalation of fires to an unacceptable level until full firefighting capabilities are deployed to mitigate the fires.

- ○ Provide plant and equipment such as remotely operated ESD valves, depressurizing valves, actuators, and critical electrical and instrument cables that must operate during a fire.
- ○ Provide items that require fireproofing to be able to remain operable for a defined period of time.
- ○ Resistance against fire.
- ○ For process plants that have their own in-house fire brigade, a minimum of 60-min fire resistance against a process fire for steel structures should be provided.
- ○ For process plants without in-house fire brigade a minimum of 120-min fire resistance should be provided.
- ○ Longer fire resistance may be required depending on the type and function of the plant equipment and risk factor.
- ○ High fire-potential equipment.

Some examples of equipment that are considered as having a high fire potential are as follows:

- Pumps with rated capacities over 34 m^3/h (150 GPM) handling light ends.
- Pumps with a rated capacity over 45 m^3/h (200 GPM) handling flammable or combustible liquids at temperatures above or within 8°C (46°F) of their flashpoint.
- Gas compressors over 150 kW (200 hp) handling flammable materials.
- Vessels and heat exchangers (including air cooled) and other equipment containing flammable liquids at or above 588.15 K (315°C or 600°F) or above their auto-ignition temperature, whichever is less.
- Reactors that operate at or above 3448 kPa (34.48 bar or 500 psig) or are capable of producing exothermic or runaway reactions.
- Fired equipment including heaters and furnaces that handle flammable materials will ignite when released.
- Drums, exchangers, columns, and similar operating vessels that handle flammable materials and have a volume of more than 3.8 m^3 (1000 gallons) including their drainage paths.
- Tanks, spheres, and spheroids that contain flammable materials including their drainage, relief path, and impounding basins.
- Any plot-limit piping manifolds that contain flammable materials with 10 or more valves.

FIRE PROTECTION ZONE (FPZ)

This is a zone which is fire prone. The steel supporting structures within the FPZ need to be fire proofed, and it should be designed with adequate drainage of potential spill of flammable liquids.

An **FPZ** includes the following:

- Ground area within 9 m (29 ft) horizontally and 12 m (39 ft) vertically containing high fire-potential equipment including a scenario of liquid fuel release.
- Elevated floors or platforms that could retain significant quantities of liquid hydrocarbons.

- The area within 9 m (29 ft) horizontally from grade up to the highest level at which an aggregated volume of flammable or reactive/toxic materials storage from vessels and equipment of more than 20 m^3 (5284 US gallons) is supported.
- The area within 9 m (29 ft) horizontally and 12 m (39 ft) vertically off the edge of an open drainage ditch that serves to transport spills from high fire-potential equipment to a remote impounding basin.
- For rotating equipment, the 9 m (29 ft) horizontal and 12 m (29 ft) vertical distance shall be taken from the expected source of leakage.

PASSIVE FIRE PROTECTION

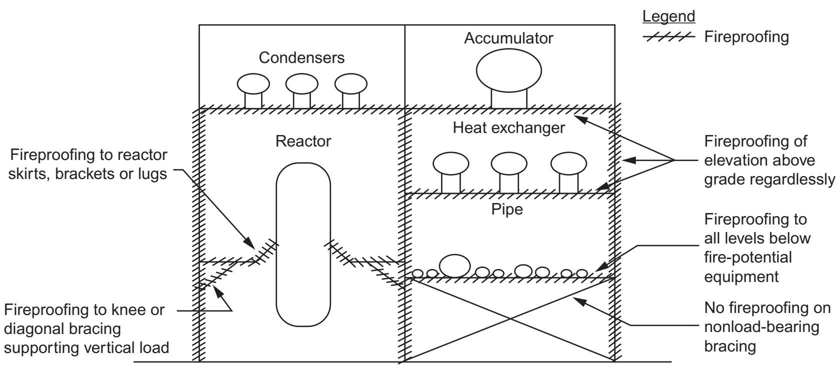


Diagram shows structure supporting high fire potential equipment having nonperforated platforms where spilled hydrocarbons can be accumulated.

FIREPROOFING FOR SUPPORTS, EQUIPMENT, AND PIPE RACKS

Equipment Type or Configuration	Conditions Governing the Need for Fireproofing		
	Location	**Service**	**Other Limiting Factors**
Single horizontal vessel such as drum or shell and tube exchanger	Within process unit area	Flammable material	Fireproof supports if both of the following conditions exist: (1) Vessel diameter >760 mm (>30 in.) (2) Support members higher than 300 mm (12 in.) at the lowest paint of measurement
	Outside process unit area	Flammable liquid only	

Continued

Equipment Type or Configuration	Conditions Governing the Need for Fireproofing		
	Location	Service	Other Limiting Factors
Stacked horizontal drums or shell and tube exchanger	Within process unit area	Flammable material	Fireproof supports to the bottom vessel and all intermediate vessels. Fireproof the supports for the top vessel only if both of the following conditions exist: (1) Vessel diameter >760 mm (>30 in.)
	Outside process unit area	Flammable liquid only	(2) Support members higher than 300 mm (12 in.) at the lowest point of measurement
Single vertical tower, drum, or shell and tube exchanger	Within process unit area	Flammable material	Fireproof all supports including inside of vessel skirts (not including vessel head).
	Outside process unit area	Flammable liquid only	
Any vessel or auxiliary equipment such as steam drums, waste heat boilers, and catalyst hoppers	Within process unit area only	Nonflammable material	Fireproof supports if vessels or auxiliary equipment is located within a fire hazardous area if both conditions exist: (1) Vessel diameter >760 mm (>30 in.) (2) Support members higher than 300 mm (12 in.) at the lowest point of measurement

PASSIVE FIRE PROTECTION

Fireproofing for electrical and instrumentation and valves are as follows:

- Critical instrument and power supply cabling serving safeguarding systems shall be installed in such a way that they are protected against direct heat radiation and flame impingement. If this is not possible special fire-resistant cables shall be used being able to withstand temperatures of at least 1366.15 K (1093°C, 2000°F) for a period of 30 min.

- Emergency shutdown valves (ESD), depressurizing systems, emergency isolation systems, plot limit valves and large groups of signal cables from control houses to main junction boxes in the plant. All these items shall be made fire resistant.

ACTIVE FIRE PROTECTION

- A fire assessment will determine the type of active fire protection system that will be required against escalation of a fire for process structures and related facility.
- An active fire protection system is a dormant system that needs to be activated in the case of a fire to perform its function (activation of water spray systems, deluge systems, sprinkler systems, fire water monitors, and steam rings around flanges). These systems will be activated once the information that protection is required is received from the scene of the fire.

Fire water supply

The purpose of a fire water distribution system is to guarantee the supply of sufficient water for the prime purpose of fire control and extinguishment at the desired flow rate and pressure at the required area (scene of fire).

Fire water should not be used for any other purpose except for firefighting.

Where possible fire water should be supplied from open water, however where fire water storage is required, a sufficient storage capacity will be required to allow enough storage for a minimum 3 h of uninterrupted water supply.

Fire water pumps

Fire water is considered a vital utility for plant operations.

The fire water pumps must be sized to allow the largest flow rate to the fire water ring main system.

There are two types of fire water pumps:

- Submerged vertical pump: if water is drawn from open water.
- Horizontal type if water is drawn from a storage tank.

The fire water pumps shall be installed at a location that is considered safe (i.e., an area that is free from explosive vapors, or damage due to collision by vehicles and/or ships) in the event of fire anywhere in the plant.

Fire water distribution systems

Fire water ring mains must provide fire water at the required flow rate and pressure and needs to be laid to surround all processing units, and storage facilities of flammable materials, loading facilities (road and rail tanker loading), process filling, tanker berthing, utilities, process laboratories, and plant control buildings.

Fire water ring main piping sizes should be calculated based on design flow rates at a pressure of 10 bar (g)/145 psig and a maximum allowable velocity of 3.5 m/s (11.5 ft/s) to prevent surging at the takeoff points.

The ring main must be provided with block valves so that sections can be isolated for maintenance.

Generally, wherever possible the ring main should be laid underground within a radius of 100 m (300 ft) from process plant equipment and pressurized storage tanks.

Ring mains can be laid above ground in low-risk areas; however, it is essential to provide good maintenance of the ring main in order to prevent corrosion in the water main.

Hydrants

Hydrants must be provided at strategic locations around the processing units and loading and unloading facilities. The hydrants need to be spaced at appropriate distances and sized to give adequate cover to the process unit/area. Hydrants need to be at an accessible location and at two sides of a unit to allow fighting the fire from an upwind direction.

Riser stacks

A riser stack system (dry or wet system with standby fire hose) is used for platforms over 10 m (30 ft) from ground level. The landing valve with the standby fire hose must be located beside all the exit staircases to comply with fire codes. **NFPA 14** code defines the three design types that can be used. All isolation valves must be located at a safe location, away from the area to be protected.

Fire foam and water monitors

A fixed manually adjustable operated foam/water monitors with adjustable nozzles must be installed at strategic points around and inside areas where the fire hazards have been identified.

The foam concentrate will be placed beside the foam/water monitors for the purpose of producing the required foam. In addition portable foam/water monitors can be provided.

Inert gas systems and steam systems

- Inert gas systems are used to prevent the creation of flammable conditions inside equipment containing a flammable product, an example being the vapor space of storage tanks.
- Remember that with the release of the vapor space gases into atmosphere a flammable mixture is formed, because the space still contains hydrocarbons.

- Steam systems can be used to smother fires, to dilute gas/air mixtures in enclosed areas, to control flange fires in plants in hydrogen service, and on equipment handling flammable products at or above their autoignition temperature.

FIRE DETECTION

A fire detection system is the first line of defense where the risk is solely due to flammable gas leakage.

There are four types of fire and gas detectors.

- Smoke sensing—detectors that respond to the presence of smoke particles.
- Heat sensing—detectors that respond when the sensing level of the device becomes heated to a predetermined level.
- Radiant energy sensing—detectors that respond to radiant energy produced by burning substances.
- Combustible gas sensing—detectors that respond to the presence of combustible gases or vapors.

NFPA 72E is a recognized code for the practice of fire protection.

The following is a list of codes for API and NFPA for fire protection:

American Petroleum Industry (API)	
API 2G	Production Facilities on Offshore Structures
API 2L	Planning, Designing and Constructing Heliports for Fixed Offshore Platforms
API 14C	Recommended Practice for Analysis, Design Installation and Testing of Basic Surface Safety Systems on Offshore Production Platforms
API 14F	Design and Installation of Electrical Systems for Offshore Production Platforms (included in the *Electrical Manual*)
API 14G	Fire Prevention and Control on Open Type Offshore Production Platforms
API 4322	Fugitive Hydrocarbon Emissions from Petroleum Production Operations. Volumes I and II (1980)
API 540	Electrical Installations in Petroleum Refineries (included in the *Electrical Manual*)
API 500	Classification of Locations for Electrical Installation in Petroleum Facilities
API 521	Guide for Pressure-Relieving and Depressuring Systems
API 752	Management of Hazards Associated with Location of Process Plant Buildings
API 2021	Guide for Fighting Fires In and Around Petroleum Storage Tanks
API 2218	Guideline for Fireproofing Practices in Petroleum and Petrochemical Processing Plants
API 2510A	Fire-Protection Considerations for the Design and Operation of Liquefied Petroleum Gas (LPG) Storage Facilities
API Guide for the Inspection of Refinery Equipment, Chapter XVI, Pressure-Relieving Devices	

National Fire Protection Association (NFPA)	
NFPA 10	Portable Fire Extinguishers
NFPA 11	Low Expansion Foam and Combined Agent Systems
NFPA 11A	Medium and High-Expansion Foam Systems
NFPA 11B	Synthetic Foam, Combined Agent Systems
NFPA 11C	Mobile Foam Apparatus
NFPA 12	Carbon Dioxide Extinguishing Systems
NFPA 12A	Halon 1301 Fire Extinguishing Systems
NFPA 12B	Halon 1211 Fire Extinguishing Systems

4.6 BLOW-OUT RESISTANCE

Blow-out resistance is the resistance of a material and/or equipment to withstand the internal pressures imposed upon it without leakage or failure.

The most common forms of blow-out resistance are as follows:

- The resistance of a flange gasket or mechanical seal to withstand pressure without leakage or failure.
- The ability of a pipe or pressure vessel to withstand the internal pressures imposed upon it without rupture, and consequent failure.

There can never be a 100% sure way of preventing failure, as many factors are involved in plant failure; however there are a series of procedures and protocols that can be put in place to reduce these failures to a minimum, and when put in place usually will reduce risks close to zero.

THE RESISTANCE OF FLANGE GASKETS

Gaskets and seals are able to withstand high pressure without failing by extrusion fracture.
A short-term leak could be resealed by tightening the bolt.
The intent is to avoid large leaks
When a flanged joint is not tightened properly
When the piping system is subjected to pressure much higher than the design
When large bending moments are applied to the flanged joint.

Failure can be by either Extrusion or Fracture

BLOW-OUT RESISTANCE—VALVES

All body and shell materials for valves must be compliant with ASME 16.34 for chemistry and strength.

The wall thickness of body and other pressure-containing components must meet ASME B16.34 specified minimum values for each pressure class.

All bolting must be of an **ASTM** grade with the maximum applied stress controlled by **B16.34.**

All NPT and SW end connections for valves and fittings must comply with **ASME B1.20.1** or **ASME B16.11**

VALVES

All valve stems will be internally loaded and blow-out proof.

Each valve shall be tested at 1.5 × rated pressure for specific time duration.

Each valve shall be permanently tagged with materials of construction, operating limits, and name of the manufacturer.

When purchasing valves according to ASME B16.34 it is advised to check that the supplier is in full compliance with this standard.

PRESSURE VESSELS

Blow-out resistance on pressure vessels and piping is handled by:

Correct design, wall thickness calculations, and code compliant to ASME BPV V111 sect 1 & 2 and ASME B31.1 and B31.3.
Pressure relief valves
Bursting disks (rupture disks)
Pipeline flexibility and design

BLOW-OUT RESISTANCE—PRESSURE RELIEF DEVICES

Pressure safety relief valves are considered one of the most important safety components within the boiler, piping, and pressure vessel industry. These devices are literally the last line of defense against catastrophic failure or even loss of life.

A pressure relief valve (PRV) is used to control or limit the pressure in a system or vessel which can build up by a process upset, instrument or equipment failure, or fire. The pressure is relieved by allowing the pressurized fluid to flow from an auxiliary passage out of the system. The relief valve is designed or set to open at a predetermined set pressure to protect pressure vessels and other equipment from being subjected to pressures that exceed their design limits.

When the set pressure is exceeded, the relief valve becomes the "path of least resistance" as the valve is forced open and a portion of the fluid is diverted through the auxiliary route. The diverted fluid (liquid, gas, or liquid–gas mixture) is usually routed through a piping system known as a **flare header** or **relief header** to a central, elevated gas flare where it is usually burned and the resulting combustion gases are released into the atmosphere.

As the fluid is diverted, the pressure inside the vessel will drop. Once it reaches the valve's reseating pressure, the valve will close.

The **blow down** is usually stated as a percentage of set pressure and refers to the pressure needed to drop before the valve re-seats. The blow down can vary from roughly 2% to 20%, and some valves have adjustable blow downs.

In systems where the outlet is connected to piping, the opening of a relief valve will give a pressure build up in the piping system downstream of the relief valve.

This often means that the relief valve will not re-seat once the set pressure is reached. For these systems often the so-called "differential" relief valves are used. This means that the pressure is only working on an area that is much smaller than the opening areas of the valve.

If the valve is opened the pressure has to decrease enormously before the valve closes and also the outlet pressure of the valve can easily keep the valve open.

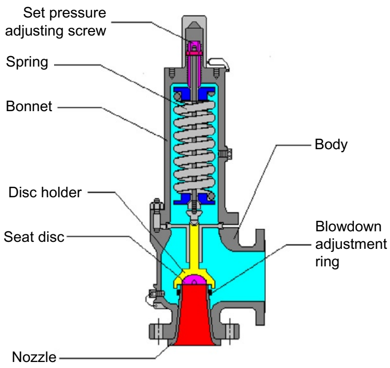
Another consideration is that if other relief valves are connected to the outlet pipe system, they may open as the pressure in exhaust pipe system increases. This may cause undesired operation in some cases, and act as a relief valve by being used to return all or part of the fluid discharged by a pump or gas compressor back to either a storage reservoir or the inlet of the pump or gas compressor.

This is done to protect the pump or gas compressor and any associated equipment from excessive pressure. The bypass valve and bypass path can be internal (an integral part of the pump or compressor) or external (installed as a component in the fluid path).

In other cases, equipment must be protected against being subjected to an internal vacuum (i.e., low pressure) that is lower than the pressure which the equipment can withstand.

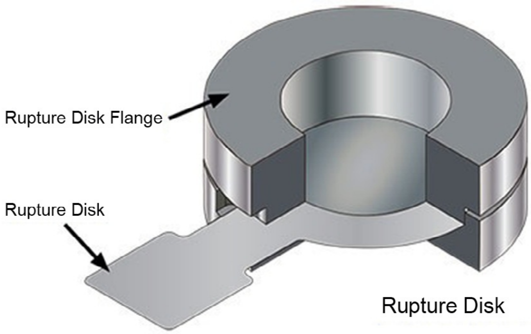
In such cases, **vacuum relief valves** are used to open at a predetermined low-pressure limit and to admit air or an inert gas into the equipment so as to control the amount of vacuum.

PRESSURE RELIEF VALVES (PRV)



BURSTING DISCS (RUPTURE DISCS)

A **bursting disc** (also known as a **rupture disc** or **bursting disk**) is designed to provide a leak-tight seal within a pipe or a vessel, until the internal pressure rises to a predetermined level. At that point the bursting disc ruptures, preventing the damage to the equipment due to overpressure.



Bursting disc

BLOW-OUT RESISTANCE—PIPING FLEXIBILITY

Other considerations in blow-out resistance are as follows:

Is the piping configuration flexible enough?
Does it allow for thermal growth and sustained forces on flanges and equipment nozzles to be maintained to a minimum, so as to not allow for excessive forces, which would then cause failure by extrusion or fracture of the gasket and possible deformation of the piping and flange?
Are the forces on anchors and valves within allowable limits as set by code?
Has an approved stress analysis of the piping layout been performed to limit these risks?

4.7 TENDENCIES TO LEAK

Leaks can occur in many ways and in a variety of circumstances; some examples are listed below:

Hydraulic leaks from hydraulic machinery,
At rotating equipment such as pumps and compressors,
At valves and flanges,
At corrosion points where the pipe wall is thin and cannot withstand internal pressures,
Weld seams on piping and fittings and vessels, where the weld is not satisfactory, and along ERW pipe,
On pressure vessels at nozzle interfaces that are not adequately reinforced,
On vessel and pipe walls, where corrosion has reduced the wall thickness below the allowable working pressure for the wall thickness.

Leakage of hydrocarbon products from pipelines, vessels, and equipment seals is not only a loss of natural resources but also a serious and dangerous environmental pollution problem and potential for a fire disaster, and possible loss of life.

The majority of leaks occur on pipelines and equipment seals, with less leaks occurring at pressure vessels.

More than half of the pipelines in the United States were built before the 1970s. These were built using low-frequency electric resistance welded (ERW) pipe. This piping does not meet today's corrosion standards, and as such considered high risk for leaks and dangerous ruptures.

A more recent pipeline leak disaster occurred in Utah, USA in March 2013 when seams of a Chevron pipeline eroded and spilled diesel near the Great Salt Lake.

Faulty welding and materials caused more than a third of all liquid pipeline leaks between 2006 and 2010.

Leaks on **pipelines, vessels,** and **equipment** can be caused by any one or many of the following.

PIPELINES

- corrosion on pipe walls
- incorrect pipe wall thickness calculations
- pipe branch connections not adequately reinforced
- improper welding
- inadequate X-ray
- use of ERW pipe
- inadequate hydrostatic test procedures
- incorrect designed piping layouts, which causes deformation of the pipeline
- incorrectly aligned flanges
- improperly tightened flanges
- incorrect gaskets
- very high sustained stresses at pipeline anchor points
- incorrect pipe supporting

VESSELS

- corrosion on vessel walls and nozzles
- improper welding
- not adequately reinforced nozzles
- incorrect materials
- vessel not designed in accordance with design code
- over pressurizing of vessel
- inadequate pressure relief devices
- not adequately supported—inadequately designed saddles

EQUIPMENT

- faulty seals
- corrosion
- misaligned drive shafts
- misaligned equipment
- incorrect lubrication, overheating
- bad materials
- equipment not to code

Advances in pipe metallurgy and welding in newly built pipelines lessen the chances of leaks. No pipes or vessels are 100% leakproof, and many older pipelines and even some older vessels have smaller leaks that go undetected for months or years before being discovered. Current leak detection techniques are good but only find around half of the leaks. As these pipeline and facility accidents are increasing due to age of components, regulators are requiring companies to do more extensive testing of older pipe, vessels, and welded seams.

API "RP 1130" documents externally and internally based leak detection systems (LDS) that can be used to detect leakage by one of the many systems.

The primary purpose of LDS is to assist pipeline controllers and plant operators in detecting and localizing leaks. Pipeline and vessel leak detection includes hydrostatic testing as well as leak detection during service.

Leak detection during service can be achieved by the following flow and pressure or fluid temperature sensors to monitor internal pipeline parameters:

- infrared radiometers or thermal cameras,
- vapor sensors, acoustic microphones, or fiber-optic cables to monitor external pipeline parameters.

Pipeline and vessel LDS are beneficial not only for safety but also for the productivity, system reliability, reduced down time, and reduced inspection time.

4.8 CORROSION RESISTANCE

Corrosion Resistance and Material selection

What is corrosion? According to NACE, corrosion is the deterioration of a substance, usually a metal, or its properties because of a reaction with its environment.

The different forms of **corrosion** as follows:

Uniform or **general corrosion**: It is the most classical form of corrosion; the consequences of uniform corrosion are a decrease in metal thickness. Uniform corrosion can be limited or prevented by the appropriate choice of materials.

Galvanic corrosion: Galvanic corrosion is the effect resulting from the contact between two different materials in a conducting corrosive environment. Choosing the correct material combinations in which the constituents are all made from the same material or different materials as close as possible in the corresponding galvanic series will minimize or prevent galvanic corrosion.

Crevice corrosion: It is an electrochemical oxidation–reduction process, which occurs within localized volumes of stagnant solution trapped in pockets in piping and equipment. Crevice corrosion is considered more dangerous than uniform corrosion as the corrosion rate is up to 100 times higher. It is encountered particularly in alloys; a classic example is stainless steel in the presence of high concentrations of chlorine ions. So not only choosing the correct materials as in this case might be Monel or 316 SS or low carbon steel, depending on whether or not it is wet or dry chlorine (refer to material compatibility charts or consult with metallurgist). Crevice corrosion can also be limited or prevented by using welds rather than bolted joints, and designing properly draining systems.

Pitting corrosion: It is characterized by the localized attack in the form of deep and narrow holes that can penetrate inwards extremely rapidly, while the rest of the surface remains intact. Pitting corrosion is most aggressive in solutions containing chloride, bromide, or hypochlorite ions. The presence of sulfides and H_2S is also detrimental to this type of attack. The stainless steels are particularly sensitive to pitting corrosion in seawater environments. Pitting corrosion can be reduced or prevented by choosing the most appropriate material for the service conditions, and by using cathodic protection (CP).

Intergranular corrosion: It is a form of attack that progresses preferentially along the paths of grain boundaries and can cause the catastrophic failure of the equipment, especially in the presence of tensile stress. This type of corrosion is either due to the presence of impurities in the boundaries, or local enrichment or depletion of one or more alloying elements. The most common example is the intergranular corrosion of austenitic stainless steels. Intergranular corrosion can be prevented by selecting the right material, avoiding low-cost equipment where the material is likely to have impurities and poor heat treatment, using low carbon or stabilized grades if welding, or applying postweld heat treatments correctly.

Stress corrosion cracking: It is a process involving the initiation of cracks and their propagation, possibly up to complete failure of a component, due to the combined action of tensile mechanical loading and a corrosive medium. The time necessary for a part to fail by stress corrosion cracking (SCC) can vary from a few minutes to several years. No commercial alloy is fully immune to SCC. Stress corrosion can be avoided by selecting materials that are not susceptible in the specific corrosion environment and minimized by stress relieving or annealing after fabrication and welding.

Structural alloys corrode from exposure to moisture in air. Corrosion process can be strongly affected by exposure to certain substances. Corrosion can be concentrated locally to form a pit or crack, or it can extend across a wide area more or less uniformly corroding the surface. Corrosion is a diffusion-controlled process, it occurs on exposed surfaces.

Methods to reduce the activity of the exposed surface, such as passivation and chromate conversion, can increase the corrosion resistance of a material.

Passivation is the use of a light coat of a protective material, such as metal oxide, to create a shell against corrosion.

Chromate conversion is a type of conversion coating (where the part surface is converted into the coating with a chemical or electrochemical process) used to passivate aluminum, zinc, cadmium, copper, silver, magnesium, and tin alloys. It is primarily used as a corrosion inhibitor, primer, decorative finish, or to retain electrical conductivity.

Hot-dip galvanizing is a form of galvanization. It is the process of coating iron and steel with a layer of zinc by immersing the metal in a bath of molten zinc at a temperature of around 840°F (449°C).

Galvanic corrosion occurs when two different metals have physical or electrical contact with each other and are immersed in a common electrolyte, or when the same metal is exposed to electrolyte with different concentrations.

Some metals are more intrinsically resistant to corrosion than other. The following is a list known as the "Galvanic Series" shown in order of corrosion resistance.

GALVANIC SERIES

- graphite
- palladium
- platinum
- gold
- silver
- titanium
- stainless steel 316 (passive)
- stainless steel 304 (passive)
- silicon bronze
- stainless steel 316 (active)
- Monel 400
- phosphor bronze
- admiralty brass
- cupronickel
- molybdenum
- red brass
- brass plating
- yellow brass
- naval brass 464
- uranium 8% Mo
- niobium 1% Zr
- tungsten
- tin
- lead
- stainless steel 304 (active)
- tantalum
- chromium plating
- nickel (passive)
- copper
- nickel (active)
- cast iron
- steel
- indium
- aluminum
- uranium (pure)
- cadmium
- beryllium
- zinc plating (see galvanization)
- magnesium


Rust


Corrosion on exposed metal

CORROSION PREVENTION

The various methods of corrosion prevention as follows:

Anodizing is an electrolytic passivation process used to increase the thickness of the natural oxide layer on the surface of metal parts.

Anodic protection (**AP**) is a technique to control the corrosion of a metal surface by making it the anode of an electrochemical cell and controlling the electrode potential in a zone where the metal is passive.

Cathodic protection is a technique used to control the corrosion of a metal surface by making it the cathode of an electrochemical cell. A simple method of protection connects protected metal to a more easily corroded "sacrificial metal" to act as the anode. The sacrificial metal then corrodes instead of the protected metal. For structures such as long pipelines, where passive galvanic CP is not adequate, an external DC electrical power source is used to provide sufficient current.


Sacrificial anodes on an offshore jacket

CORROSION PREVENTION

Corrosion inhibitor is a chemical compound that, when added to a liquid or gas, decreases the corrosion rate of a material, typically a metal or an alloy. The effectiveness of a corrosion inhibitor depends on fluid composition, quantity of water, and flow regime.

Galvanization is the process of applying a protective zinc coating to steel or iron, in order to prevent rusting.

Hot-dip galvanization is a form of galvanization. It is the process of coating iron, steel, or aluminum with a thin zinc layer, by passing the metal through a molten bath of zinc at a temperature of around 860°F (460°C). When exposed to the atmosphere, the pure zinc (Zn) reacts with oxygen (O_2) to form zinc oxide (ZnO), which further reacts with carbon dioxide (CO_2) to form zinc carbonate ($ZnCO_3$), a usually dull gray, fairly strong material that stops further corrosion in many circumstances, protecting the steel below from the elements.

The methods mentioned are the main ones used in the process industries, however there are many forms of rustproofing, which by definition is a process or treatment whereby the rate at which objects made of iron and/or steel begin to rust is reduced.

4.9 MATERIAL TOUGHNESS

Toughness is the ability of a material to absorb energy and plastically deform without fracturing.

Another definition of material toughness is the amount of energy per volume that a material can absorb before rupturing. It is also defined as the resistance to fracture of a material when stressed.

Toughness requires a balance of strength and ductility.

Toughness can be determined by measuring the area (i.e., by taking the integral) underneath the stress–strain curve and its energy of mechanical deformation per unit volume prior to fracture. The explicit mathematical description is

$$\frac{\text{energy}}{\text{volume}} = \int_0^{\varepsilon_f} \sigma d\varepsilon$$

where ε is strain, ε_f is the strain upon failure, and 0 is stress.

Another definition is the ability to absorb mechanical (or kinetic) energy up to failure. The area covered under stress-strain curve is called toughness.

Toughness is measured in units of joules per cubic meter (J/m^3) in the SI system and inch-pound-force per cubic inch (in. lbf/in.^{3}) in US customary units.

Toughness is related to the area under the stress-strain curve. To be tough, a material must be both strong and ductile.

For example, **brittle** materials that is strong but with limited ductility is not tough.

Ductile materials with low strengths are also not tough. To be tough, a material should withstand both high stresses and high strains.

Strength indicates how much force the material can support, while toughness indicates how much energy.

Fracture toughness is a property which describes the ability of a material containing a crack to resist fracture, and is one of the most important properties of any material for many design applications.

Fracture toughness is a way of expressing a material's resistance to brittle fracture when a crack is present. If a material has much fracture toughness it will probably undergo ductile fracture.

Hardness measures the resistance of solid matter to various kinds of permanent shape change when a force is applied.

Hardness is dependent on ductility, elastic stiffness, plasticity, strain, strength toughness viscoelasticity, and viscosity.

Resilience is the ability of a material to absorb energy when it is deformed elastically, and release that energy upon unloading.

Proof resilience is defined as the maximum energy that can be absorbed within the elastic limit, without creating a permanent distortion.

Mechanical shock is a sudden acceleration or deceleration caused, for example, by impact, drop, kick, earthquake, or explosion. Shock is a transient physical excitation.

In 1900 Swedish engineer Johan August Brinell, proposed the first widely used and standardized hardness test in engineering and metallurgy.

Brinell scale characterizes the indentation hardness of materials through the scale of penetration of an indenter, loaded on a material test-piece. It is one of the several definitions of hardness in materials science.

- The typical test uses 10 mm (0.39 in.) diameter steel ball as an indenter with a 3000 kgf (29 kN; 6600 lbf) force. For softer materials, a smaller force is used; for harder materials, a tungsten carbide ball is substituted for the steel ball. The indentation is measured and hardness calculated as

$$\mathrm{BHN} = \frac{2P}{\pi D\left(D - \sqrt{D^2 - d^2}\right)}$$

where P is the applied force (kgf), D is the diameter of indenter (mm), and d is the diameter of indentation (mm).

What is Fracture Toughness?

Toughness is fracture toughness versus strength.

Strength is resistance to plastic flow and thus is related to the stress required to move dislocations through the solid. The initial strength is called the *yield strength*. Strength generally increases with plastic strain because of work hardening reaching a maximum at the *tensile strength*. The *tensile strength* is related to the strength of atomic bonds.

Toughness is the resistance of a material to the *propagation* of a crack. A material with low fracture toughness, if it contains a crack, may fail before it yields. A tough material will yield work harden even when cracked—the crack makes no significant difference.

The ability to build a structure that is defect free (completely without cracks) is almost impossible due to the following reasons:

- cracks already in material (inclusions or voids)
- cracks caused by shrinkage in castings and welding
- cracks caused by machining
- cracks caused by cyclic loading (fatigue)
- cracks caused by corrosion

A material with an adequate amount of toughness must be chosen for the application, for example:

- Is a stainless steel or other alloy steel required (or even UPVC or GFRP) for the application due to product acidity, corrosion, or erosion?
- Is a low-temperature steel required due to cryogenic conditions?
- Is a high temperature carbon steel material required?
- Is a lined pipe or vessel required due to product properties?

BRITTLE FRACTURE

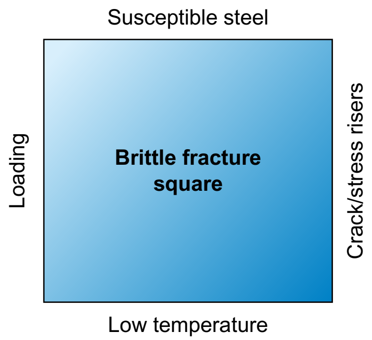
Brittle fracture which can be a cause for failure is of a major concern for low-temperature vessels and pipework. Many metals lose their ductility and toughness; they become susceptible to brittle fracture as the metal temperature decreases. At normal or higher temperatures, a warning is normally given by plastic deformation (bulging, stretching, or leaking) as signs of potential vessel failure.

However, under low-temperature conditions, no such warnings of plastic deformation are given. An abrupt fracture can cause a catastrophic event.

Only materials that have been impact tested to ensure metal toughness at or above a specified metal temperature should be used. However, certain paragraphs in the ASME Pressure Vessel Code that apply to low-temperature vessels indicate that when impact testing may not be required for a pressure-vessel component material (impact test exemptions).

There are four main factors, in combination, can cause brittle fracture in steel vessels.

These factors are represented in the form of "brittle fracture square."



Brittle fracture square affecting carbon and alloy steels at low temperature.

A metal depending on its toughness property has a transition temperature range, within which it is in a semibrittle condition (ductile to brittle transition). Within this range, a notch or crack may cause brittle fracture (notch brittleness). Above the transition range (warmer), brittle fracture will not happen even if a notch exists. Below the transition range (colder), brittle fracture can happen even though no notches or cracks exist.

The type and level of mechanical/thermal loading will affect the pipe or vessel's susceptibility to brittle fracture. Dynamic loading associated with cyclic mechanical/thermal or impact loading, as opposed to quasistatic loading, is a brittle-fracture contributing factor. Furthermore, shock-chilling effects, defined as rapid decreases in equipment temperatures, can be a cause of brittle fracture.

Susceptibility of steels depends on several parameters such as poor toughness, material flaws (cracks and notches), corrosion vulnerability, large thickness, etc.

Steels with lower carbon content (C) are proven to have higher toughness at lower temperatures. Also, phosphorous (P) present in steels decreases the transition temperature of steel and improves weld ability.

Steel-transition temperature is a function of carbon content percent plus 20 times the percentage of phosphorous.

Adding nickel to steel can increase steel toughness and decrease its transition temperature. For example, stainless steel 304 with 8% nickel can resist impact loads at −320°F.

Sufficiently low carbon equivalents contribute to the weld ability of the material (reducing hardness and cold-cracking susceptibility) and, thus, making metal crack-free girth welds. Selecting the appropriate welding material also is a determining factor to ensure a crack-free weld.

Hydrogen cracks—hydrogen embrittlement (hydrogen-induced cracks or the so-called flakes). When hydrogen atoms diffuse into the metal during material manufacturing operations such as forming, forging, and welding or when hydrogen is introduced to the metal through a galvanic or hydrogen sulfide (H_2S) corrosion process, the metal is prone to hydrogen cracks.

There are various techniques to prevent hydrogen cracks, including appropriate heat treatments or slow cooling after forging, in which the hydrogen within the metal diffuses out. In the case of welding, usually preheating and postheating are applied to diffuse out the hydrogen and to prevent any cracks and brittleness.

Environmental stress fracture. Steels exposed to corrosive fluids such as wet H_2S, moist air, or seawater are prone to premature fracture under tensile stresses, considerably below their "fracture toughness" threshold. Suitable steel materials should be used when there is a possibility of exposure to corrosive fluids.

Steel vessels with thicker walls have a greater probability of potential for brittle fracture due to the larger thermal gradient across the wall thickness. Thicker metal walls can result in differential expansion of material across the wall thickness and could possibly lead to a crack occurrence and eventually brittle fracture.

Stress raisers such as sharp or abrupt transitions or changes of sections, corners or notches (as may be found in weld defects) as a result of design or fabrication processes are all stress risers, which can cause stress intensification. The weak points are prone to brittle fracture when other susceptible conditions exist.

Proactive measures can ensure resistance of carbon or low-alloy steel vessels against brittle fracture under quasistatic loading.

Design pressure vessels, if justifiable, by analysis in accordance with the ASME Section VIII, Div. 2 part 5, or other internationally recognized codes that result in lower wall thicknesses.

It is necessary to order vessel materials from reliable and capable manufacturers. Key vessel components still require attention to proper heat treatment, avoiding hydrogen cracks, quality control, etc.

Specify fine-grain steel materials with appropriate specifications and require production tests for plate/piece (from the same heat) if an impact test is not requested. Ensure that the steel with fine-grain microstructure/toughness is supplied; do not rely just on the material certificates. Also, conduct impact tests on test pieces to verify required toughness.

Do **nondestructive testing (NDT)** to identify cracks or reject materials with detectable cracks.

Eliminate "stress risers," at the design and fabrication stages.

Verify full-penetration welds with adequate toughness using appropriate welding material/processes and require weld-procedure qualification and production-weld test specimens for both the weld and heat-affected zone for each weld process.

Conduct proper vessel **postweld heat treatment (PWHT)**, preferably in a furnace in one piece whenever practical, and examine heat-affected zone hardness to ensure the beneficial effects of the performed **PWHT.**

Perform the vessel hydrostatic test in accordance with the rules of the **ASME Section VIII** Code or other internationally recognized codes.

Fracture toughness is an important property of any material for virtually all design applications; it indicates the ability of a material containing a crack to resist fracture.

Proper **PWHT** reduces residual stresses, improves the resistance of the hard heat-affected zone to environmental cracking, and improves the toughness.

4.10 COST

Project costs are made up of the following:

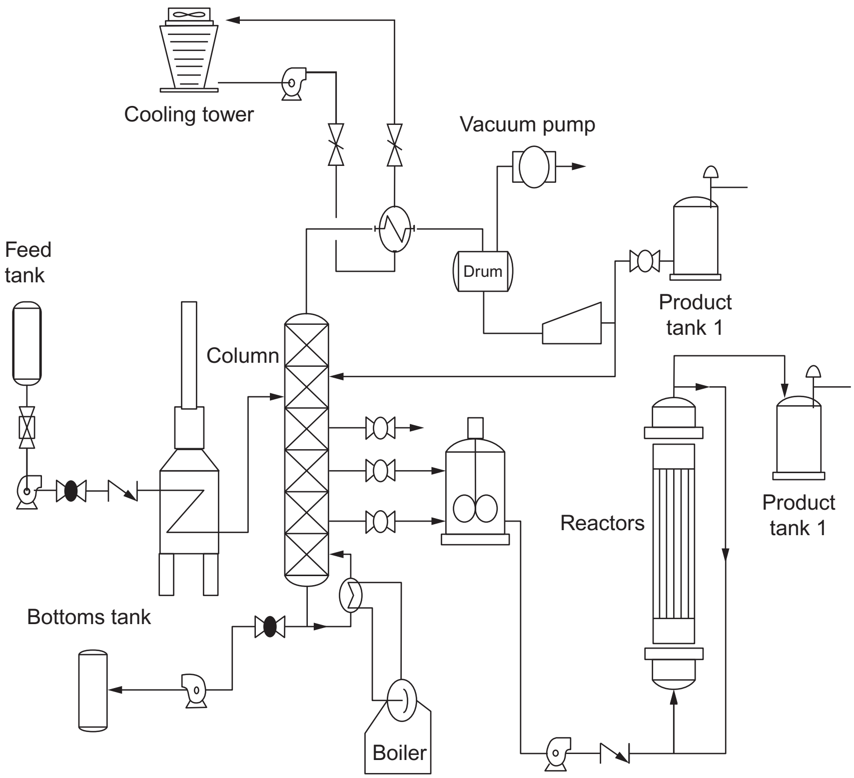
- design costs $
- direct labor hours $
- indirect labor hours $
- total labor costs $
- hardware acquisition $
- software acquisition $
- total equipment acquisition costs $
- consulting $
- subcontractor $
- travel and living $
- financial $
- total other costs $
- contingency costs $
- total project costs $
- potential causes of increase in cost or effort

There are two types of piping cost estimates.

- Approximate:
  - first cost estimate 30%
  - second cost estimate 60%
- Itemized:
  - third cost estimate 90%
  - final issue for cost (IFC) estimate 100%

First cost estimate 30% can be taken from a Flow sheet or a P&ID.

This is where you will use the P&ID along with the plot plan to determine the number of bends fittings, pipe lengths, etc.



This **first check bulk MTO (material take off) estimate (30%)** is done at the beginning of a project to determine the initial material costs.

This can be followed by a **60% estimate** further into the project, or if enough detail and information is available at the start of a project then it might be deemed to produce the 60% estimate as the first estimate.

By the end of the 90% model review a **90% MTO estimate** can be performed. This will be extracted directly from the computer model, so will be accurate.

Similarly, when the **100% IFC** stage of the 3D model is complete, then a final piping and fittings MTO will be complete.

PROJECT COSTS

Design costs +
[+direct labor Hours
+Indirect labor Hours

=Total labor costs]
+Hardware acquisition
+Software acquisition
+Total equipment acquisition costs
+Consulting
+Subcontractor
+Travel and living
+ Financial +Total other costs +Contingency costs
= Total project costs

POTENTIAL CAUSES OF INCREASES IN COST OR EFFORT

Increase in labor costs:

Project activities require more effort than planned, resulting in increased labor costs; unplanned, paid overtime is required to complete the activities on schedule; and more expensive resources than planned are assigned to the project.

EQUIPMENT ACQUISITION COST

Additional hardware, software, or both are needed by the project team to complete the project. Additional production hardware, software, or both are needed to run the completed application. The cost of acquiring hardware is higher than originally planned; or the costs of acquiring software or software licenses is higher than originally planned.

OTHER COSTS

- consulting costs are higher than planned
- additional subcontractor effort is needed
- more travel than was planned is required
- financing costs are higher than expected
- project control procedures
- increased costs of raw materials
- transportation costs
- manufacturing costs
- single-sourced vendors
- multisourced vendors
- rework
- scope change
- improper design checks
- ineffectual management of high value (low cost) engineering centers
- proprietary licensors
- feedstock increase costs
- upstream costs
- downstream cost

IDENTIFICATION OF COST AND EFFORT PROBLEMS

There is weekly (or other) review of activity status and estimates to complete work packages.

Each current activity will be reviewed and an estimate to complete it will be made.

The estimate to complete (ETC) will be added to the effort already spent. A potential cost increase occurs when that total (EAC) exceeds the original estimate.

There is weekly (or other) review of unplanned requirements such as equipment, staff, or consulting resources. The adequacy of current resources, human, and equipment will be reviewed.

A potential cost increase occurs when the need for additional resources is identified. There is weekly (or other) review of customer activities and performance.

The response of the customer team will be reviewed, particularly for current activities. A potential cost increase occurs when there are delays in responsiveness or customer decisions.

There is weekly (or other) review of risks and changes to risks. The current status of risks will be reviewed as described in the Risk Management Plan. A potential cost increase occurs when existing risks have become riskier or when new risks have been identified.

There is weekly (or other) review of changes to scope, approved or otherwise, the current status of scope compliance will be reviewed as described in the Scope Management Plan. A potential cost increase occurs when unapproved scope changes are being carried out.

RESOLUTION OF COST PROBLEMS

Accept the cost increase: both projects and client must accept costs.

Reduce the scope: the project manager will consult with the customer to determine if the scope can be reduced and, if so, what items of functionality can be eliminated or deferred.

Obtain **approval for cost increases:** Where the cost increases, the project manager will review the impact with (for time and materials contracts) or the management of (for fixed price contracts) and obtain approval to accept the increased cost. This may mean further expenditures for items such as equipment or consulting services.

Reduce the impact of cost increases: Reduce the costs associated with the project by lowering labor charge rates, negotiating reduced consultant charges, applying costs to other charge centers, implementing unpaid overtime, replacing consultants by in-house staff, and reducing travel.

APPLY CONTINGENCY

Contingencies are under the sole control of the management. The application of contingency will be transparent to client and will occur when the project manager makes a request to company management to apply it.

To apply contingency identify the reason for the cost increase or schedule slippage and the expected total impact and seek approval from the client.

REFERENCE

Fabrycky, W.J., Blanchard, B.S., 1991. Life-Cycle Cost and Economic Analysis. Prentice Hall, Englewood Cliffs, NJ, 1991.

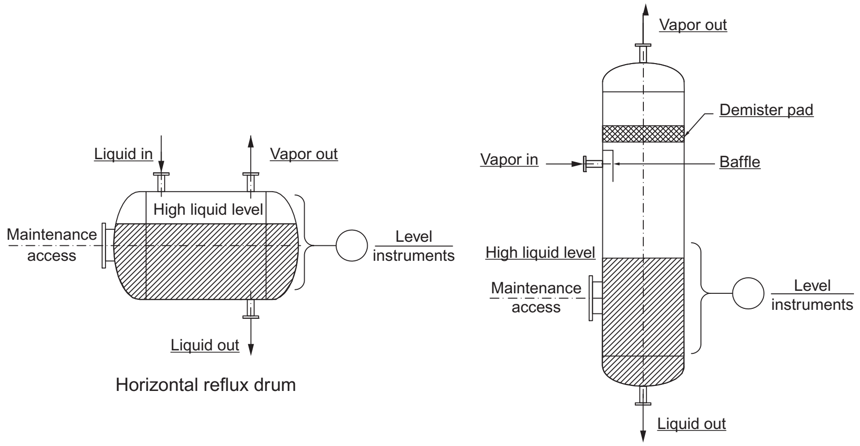
CHAPTER

Vessels and drums

5

5.1 TYPES OF VESSELS AND DRUMS

Basically vessels and drums are the same thing, and can be called either. We will use both terms in this book, but remember when we say drum or vessel we refer to the same item of equipment.



Horizontal reflux drum

Vertical compressor suction drum

Typical process unit vessels and drums are used for applications such as Flare, Refluxing, Surge, Suction, Steam Drums, Deaerators, Liquid Collection, and Storage. Vessel and drums have internals, these normally comprise of one or more of the following:

- Demister Pads
- Baffles
- Vortex Breakers
- Distribution Piping

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00005-9

5.2 VESSEL AND DRUM LOCATION

The layout engineers responsibility is to determine the following:

- Vessel or drum location within the plant
- Nozzle locations
- Support locations
- Platforming for operator and maintenance access

When determining these locations, the engineer must take into consideration the structural and piping configurations, as well as the instrument requirements.

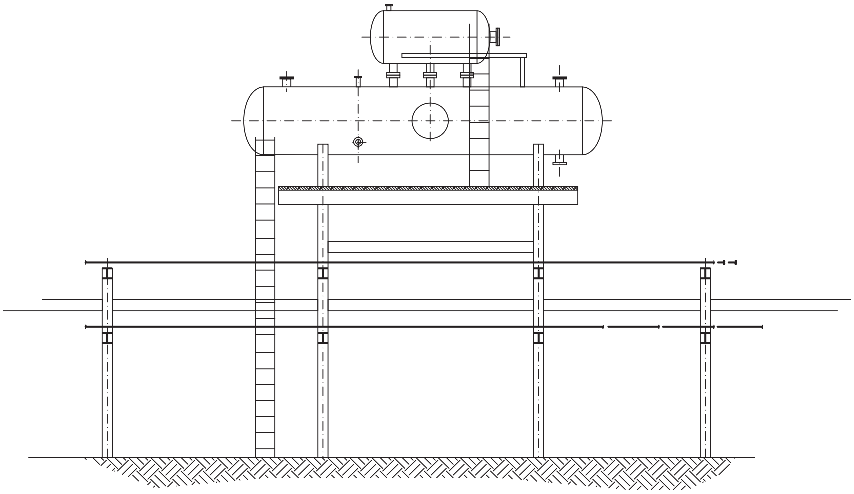
Process vessels and drums shall be located either:

- Adjacent to related equipment, for example: Reflux Drum.
- Standalone, for example: Deaerators, Condensate Collection Drums, Flare Drums

The vessel or drum shall be located to facilitate:

- Economic, flexible, and operable piping layout
- Allow access, maintenance, operability of instruments, and safe egress from the equipment
- The required NPSH

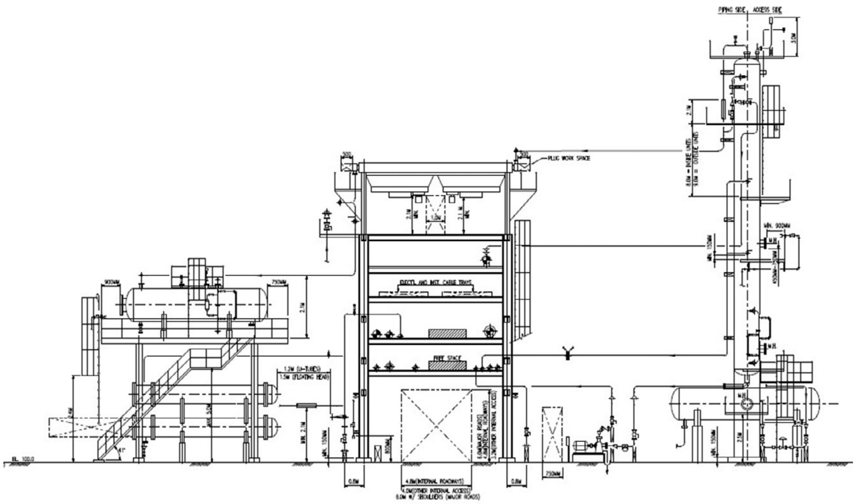
Vessels and drums are usually located on either side of pipe racks, and are serviced by auxiliary roads for maintenance and access. Vessels and drums can also be located (when required for process reasons) above pipe racks, for example: flash drums and deaerators.



Deareator at pipe rack

Vessels and drums can also be located in a structure, the location of which is determined by:

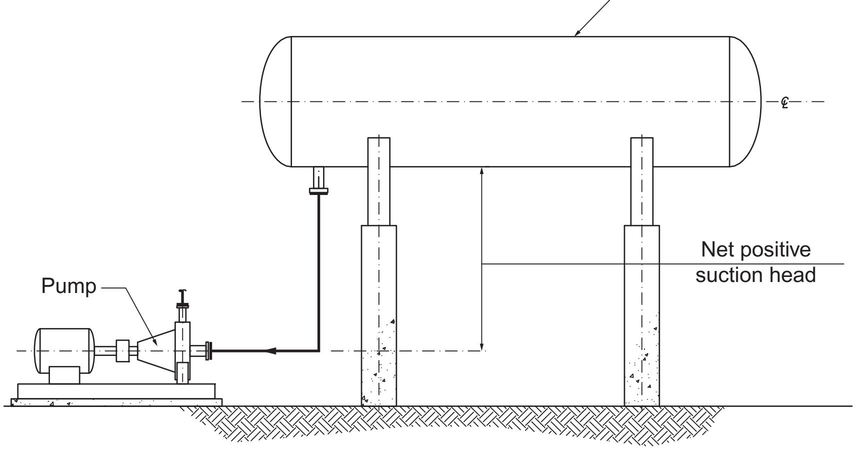
- Process requirements
- Requirements of associated equipment
- NPSH (net positive suction head) required



VESSEL AND DRUM LOCATION

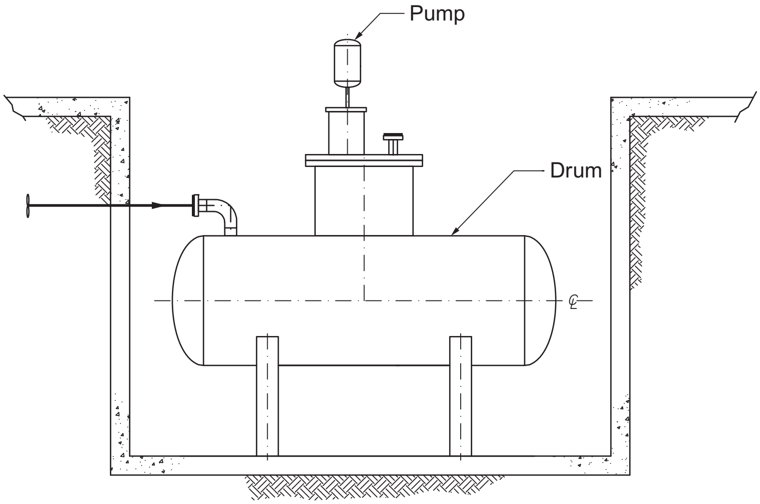
In chemical facilities (and when required in oil and gas facilities) vessels and drums will usually be located in structures or even buildings.

The vessel or drum can be located above the minimum NPSH requirements to allow for height restrictions in a structure, but must never be located below the required NPSH minimum elevation.



NPSH at pump

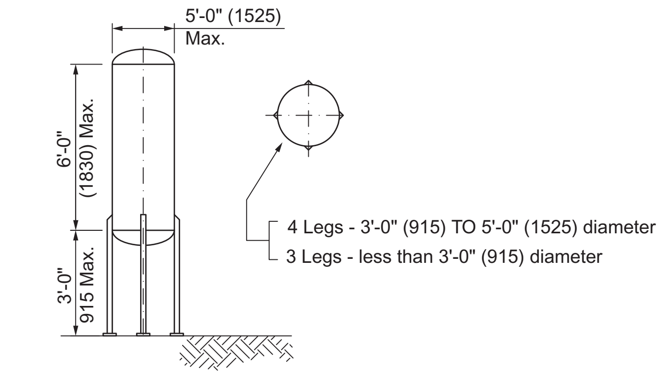
Vessels and drums that are used for collection systems such as oily water drains and chemical systems are usually located below ground level.



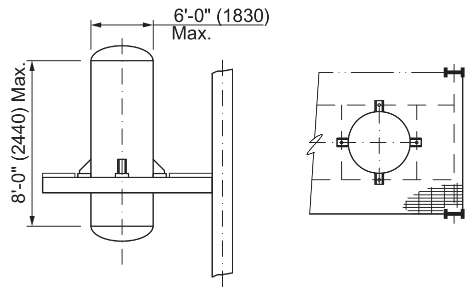
Vessel and drum location

5.3 VESSEL AND DRUM SUPPORTS

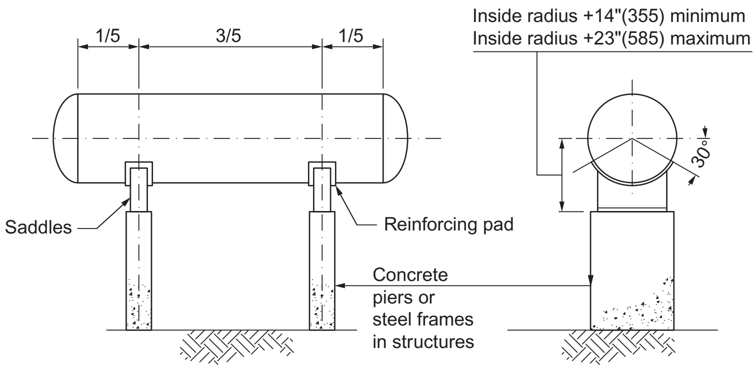
Horizontal drums are usually supported by saddles from concrete piers or steel frames.



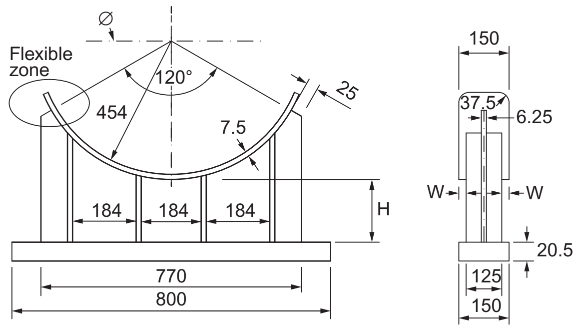
Leg-supported drum



Lug-supported drum



Saddle-supported drum



Saddle design

5.4 NOZZLE LOCATIONS

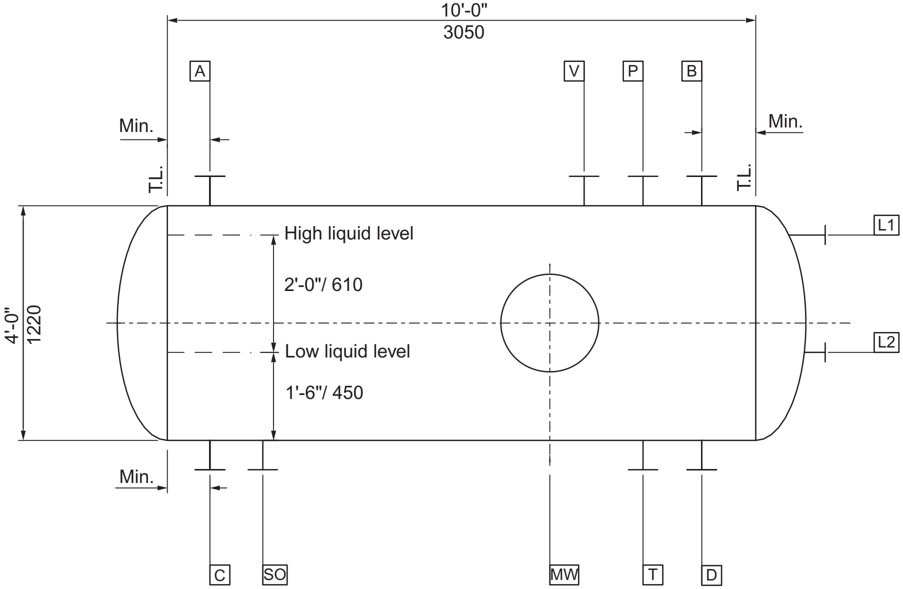
The first step in vessel or drum layout is to set the height based on the required NPSH and available headroom.

The following information is required to achieve this:

- Dimensions of the vessel or drum
- Type of heads
- Support details
- NPSH requirements of the pump
- Bottom outlet size
- Minimum clearances location, plot plan
- Nozzle summary
- Insulation requirements
- Process vessel sketch, instrument vessel sketch, P&ID

Once these parameters have been determined, the engineer can then determine the nozzle locations of the vessel. The first step for this is to review the process vessel sketch and nozzle summary supplied by the process department.

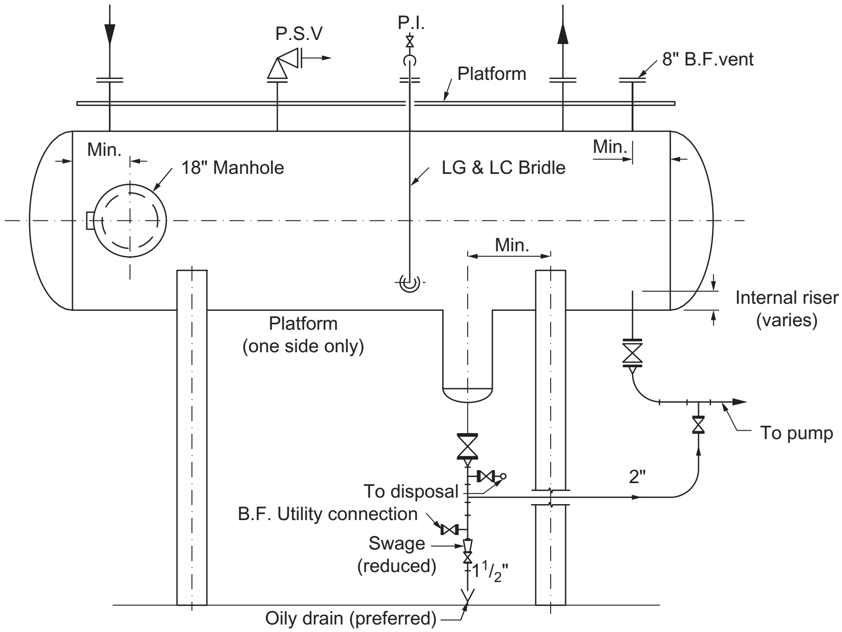
Process vessel sketch



Nozzle summary

Symbol	Size	Service
A	$1^1/_2$" 150# RF	Vapor out
B	6" 150# RF	Liquid in
C	4" 150# RF	Liquid out
D	2" 150# RF	Drain
V	1" 150# RF	Vent
SO	1" 150# RF	Steam out
MW	24" 150# RF	Manway
L	2" 150# RF	Level
P	1" 150# RF	Pressure
T	1" 150# RF	Temperature

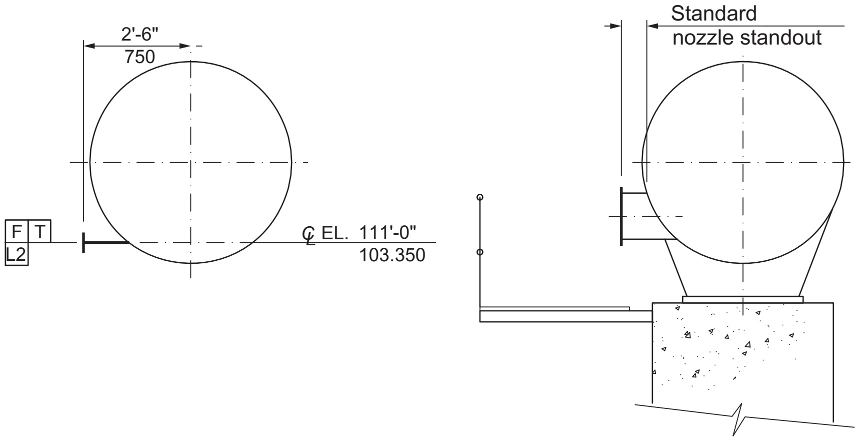
Nozzle summary — horizontal drum



Nozzle locations

When locating level instruments, the preferred location is away from any turbulence at the liquid inlet and outlet nozzle.

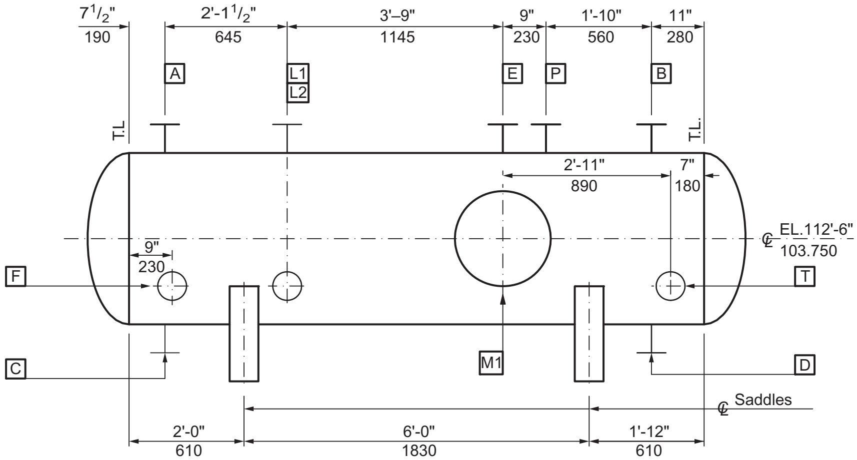
- Instrument nozzles should be set in the "Quiet Zone" of the vessel such as the opposite sides of weirs or baffles, or near the vapor outlet.
- Process nozzles should always be places at a minimum from the tangent line (first nozzle placed at 5″/125 mm, from TL to OD of nozzle).
- Steam out connections should be located at the opposite end to the maintenance access (MW) and vent, and this should be placed in the bottom section of the drum.
- Pressure instruments should be located in the vapor space.
- Temperature instruments should be located in the liquid space.
- Drains should be located in the bottom section of the drum.
- For specific elevations of nozzle requirements for level instruments, what we call a "Hillside" connection is used.



Nozzle locations

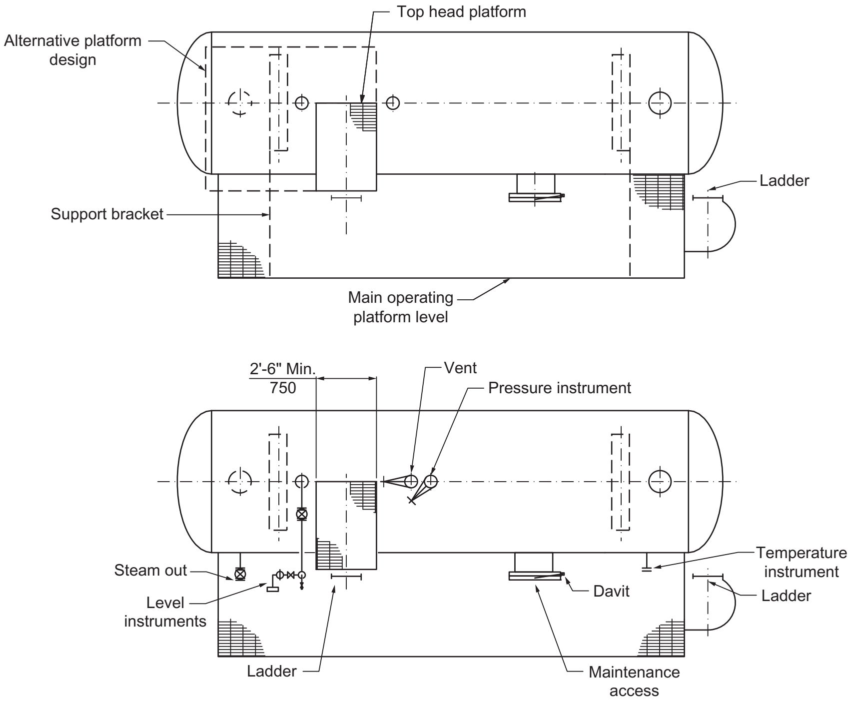
Hillside nozzle locations.

Vessel sketch showing nozzle locations and elevations on horizontal drums.



Nozzle locations on horizontal drum

5.5 PLATFORM ARRANGEMENTS



Horizontal vessel platforms (drum) (TYP.)

Typical platform arrangement on a horizontal vessel (drum).

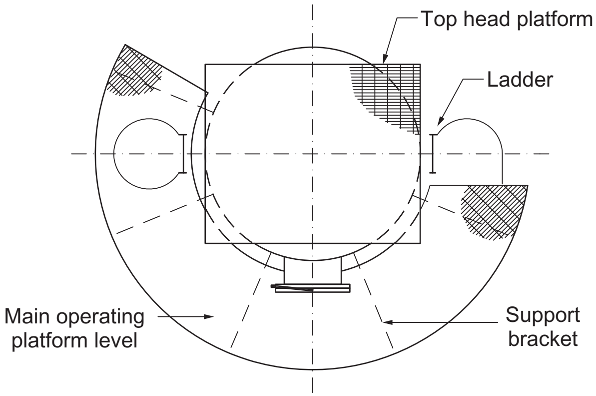
Platform arrangements at horizontal and vertical vessels (drums):

Tall vertical vessels usually have circular platforms supported by brackets attached to the shell of the vessel.

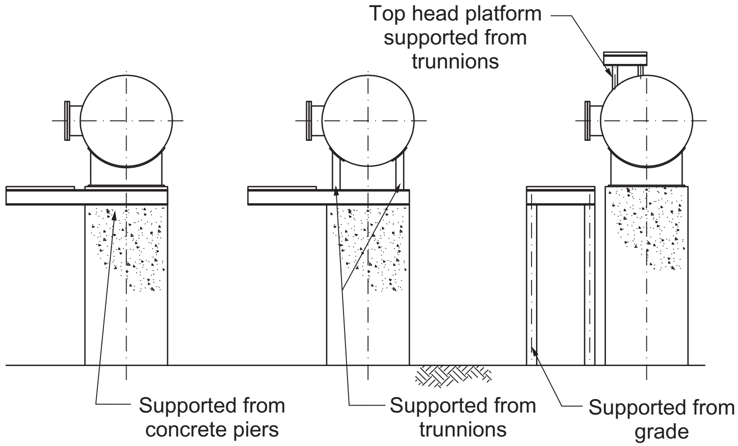
Whereas the platforms at horizontal vessels have the support attached either to the concrete piers structure or to the shell of the drum.

Vessels located in structures use the floor structure for support.

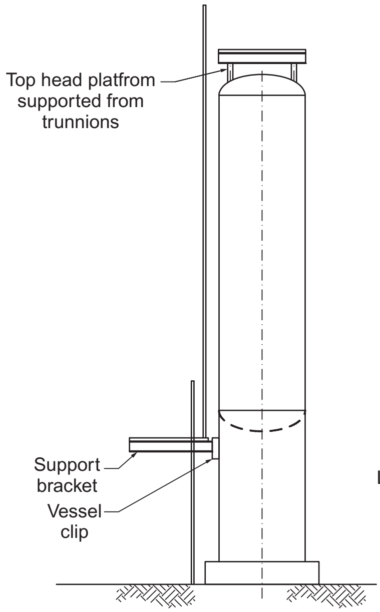
Top head platforms on horizontal and vertical vessels are supported by trunnions attached to the vessel head (vertical vessels) or shell on horizontal vessels (drums).



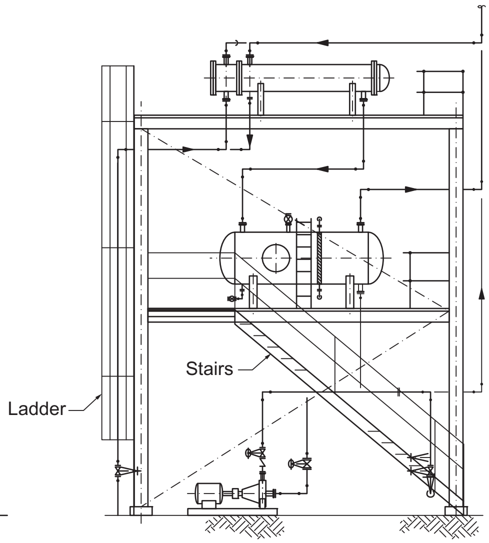
Platforms at vertical vessel



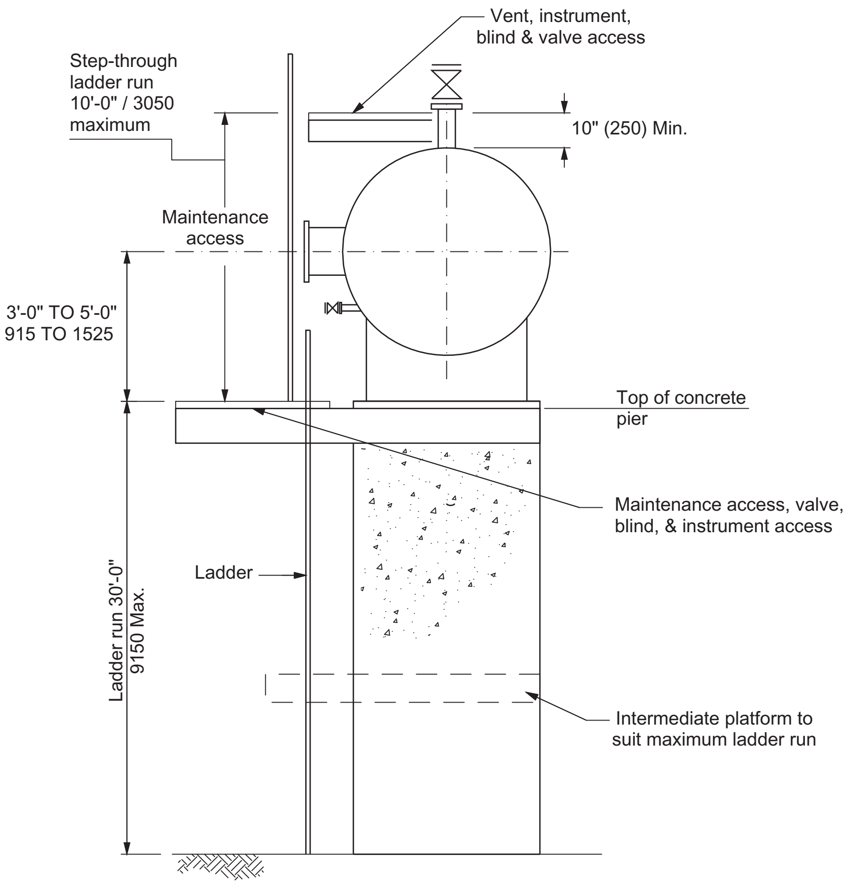
Horizontal drum platform locations



Platforms at vertical vessel



Typical piping arrangement
for exchanger & drum in structure



Horizontal drum platform and ladder elevation requirements

5.6 PIPING ARRANGEMENTS

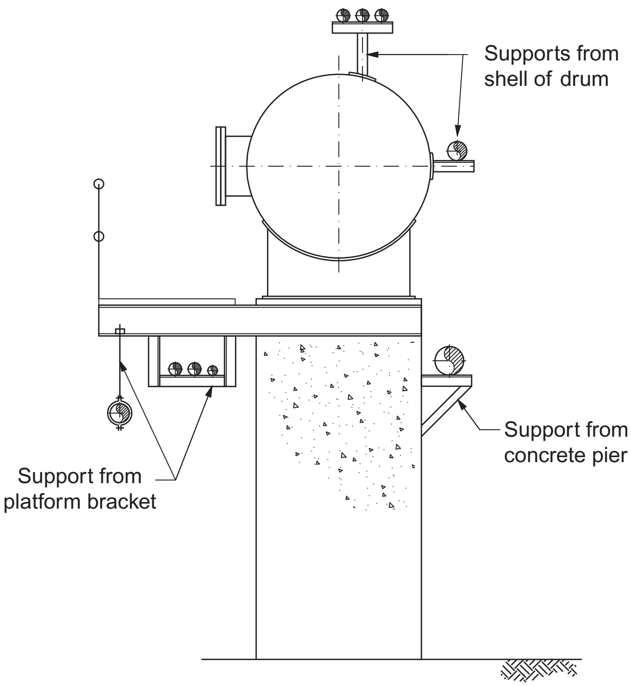
Piping arrangements at a vessel (drum) must be arranged to suit the following:

- Vessel location
- Related equipment
- Structural considerations
- Flexibility of piping (reduction of stresses, thermal growth)
- Ability to support piping

- P&ID
- Access
- Operations

Piping at horizontal vessels and drums can either be supported from:

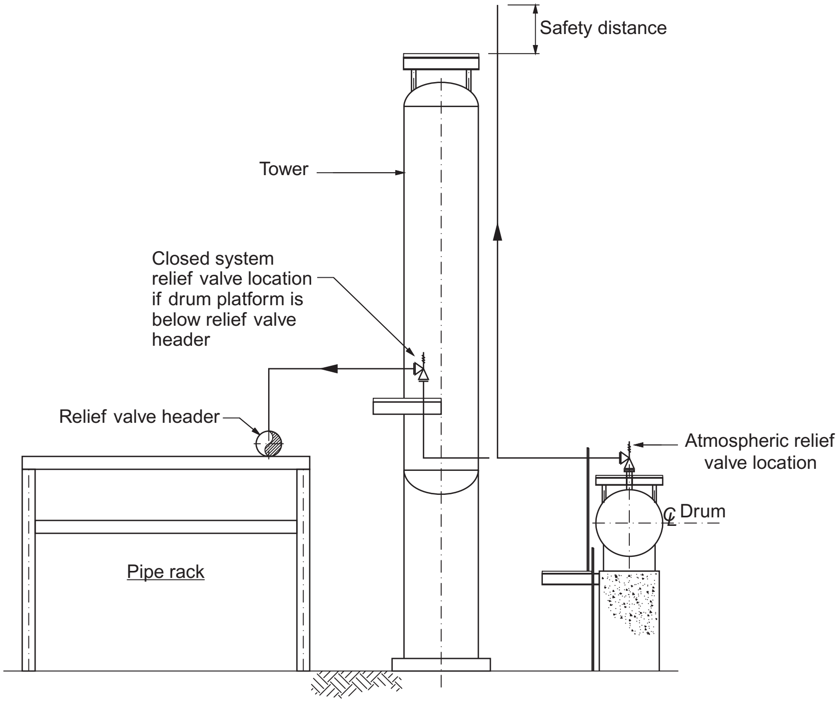
- Vessel shell
- Platform steel
- Concrete piers
- Support steel when vessel is located within a structure



Pipe supports around Vessel Horizontal Vessel

Relief valves (open to atmosphere) situated on low elevated vertical or horizontal vessels, must be positioned to allow for the discharge piping to be routed to a convenient safe location.

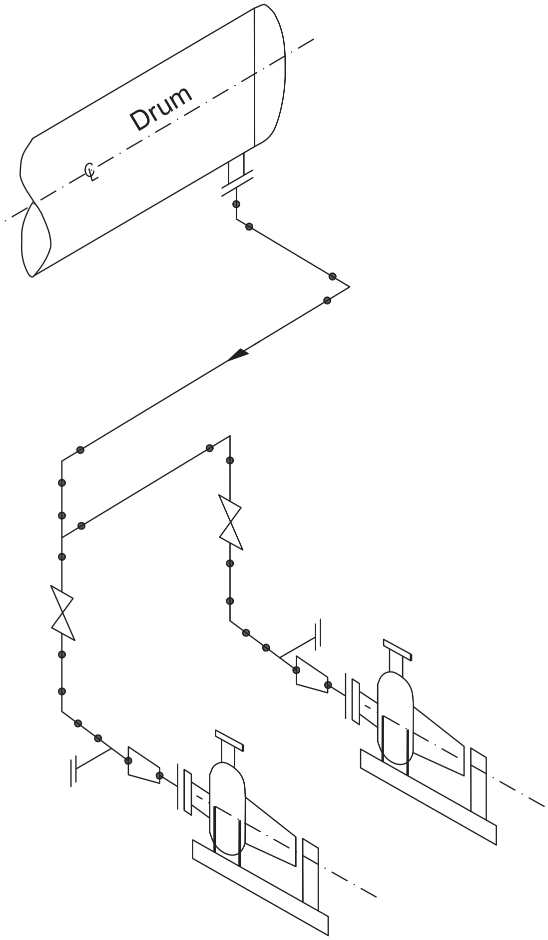
Open end of relief valve piping should terminate e at a minimum of 10′–0″/3 m above any platform, and the discharge opening should be pointed downwind.



Relief valve systems

Closed system relief valves should be located either on a dedicated common relief valve platform or at a platform adjacent to the vessel, but in all cases the relief valve must be located above the main relief valve header, so as to avoid any possibility of pockets.

If the relief valve inlet piping exceeds 20′–0″/6 m, it should be checked by the process engineering group to determine if the line size needs to be increased to allow for pressure drops.



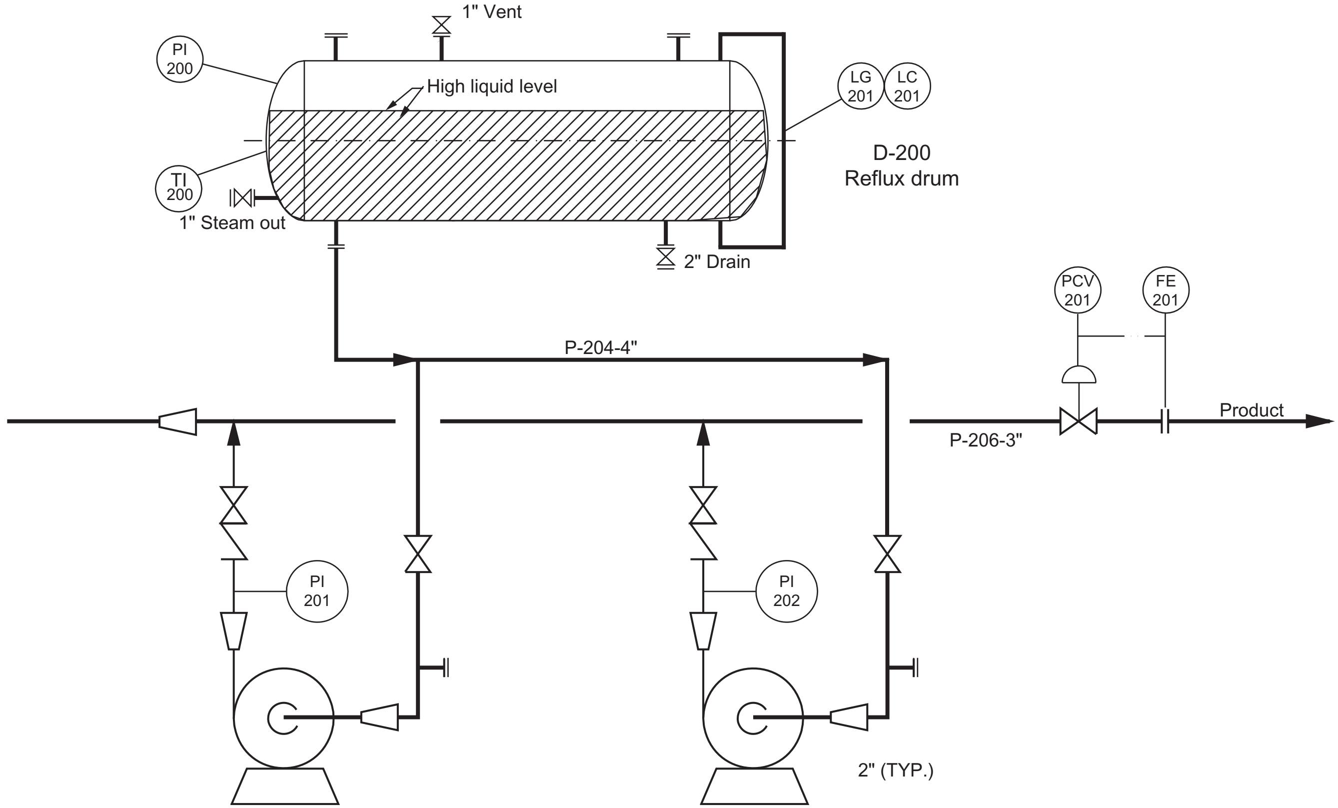
5.7 VESSEL AND DRUM INSTRUMENTATION

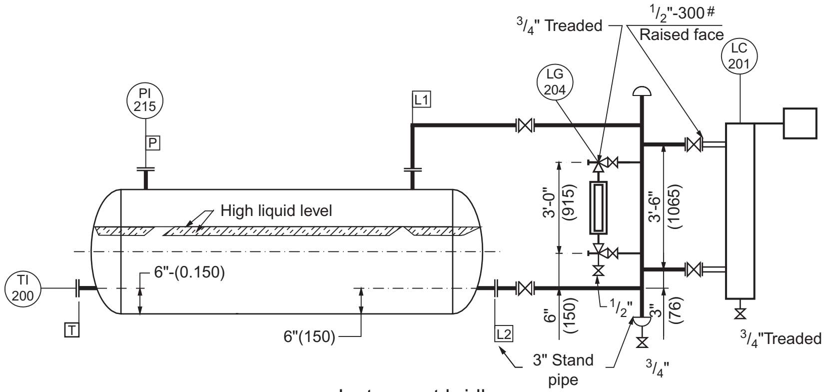
There are three basic types of instrumentation used to control the contents of a vessel or drum:

- Level
- Pressure
- Temperature

These instruments should be located in an optimum position for operation and maintenance.

The instrument requirements will be shown on the P&ID, and on an instrument vessel sketch provided by the instrument engineer.

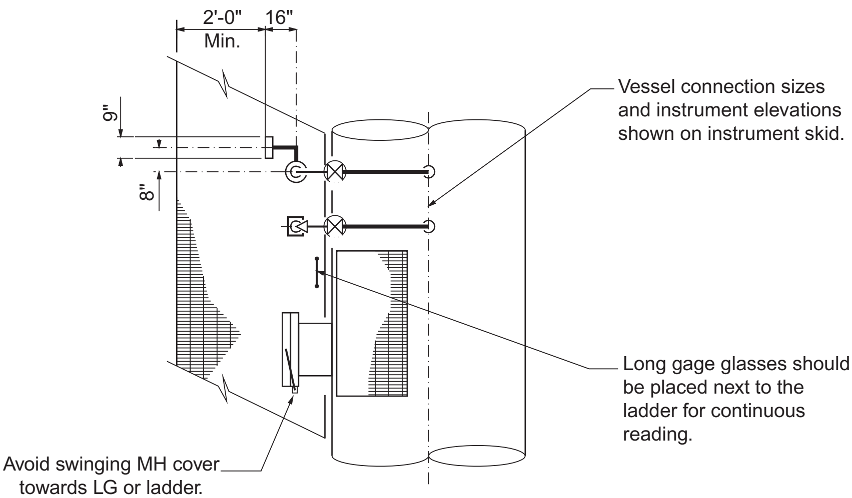

1" Vent
PI 200
High liquid level
LG 201
LC 201
D-200
Reflux drum
TI 200
1" Steam out
2" Drain
PCV 201
FE 201
P-204-4"
Product
P-206-3"
PI 201
PI 202
2" (TYP.)



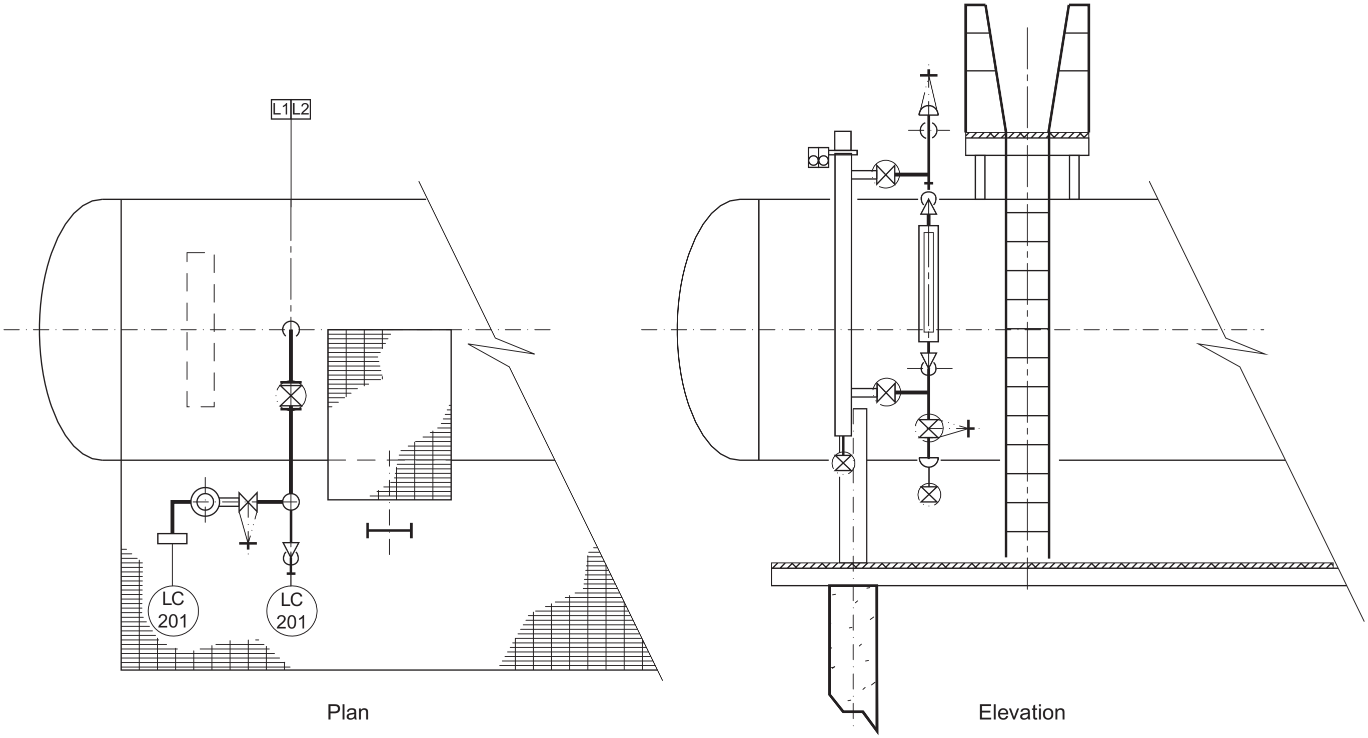
Instrument bridle

Arrangement of an instrument bridle showing locations of nozzles schematically:

Nozzles P and L1 are located in the vapor space
Nozzles T and L2 are located in the liquid space
The 3″ standpipe (bridle) spans across the liquid and vapor space.



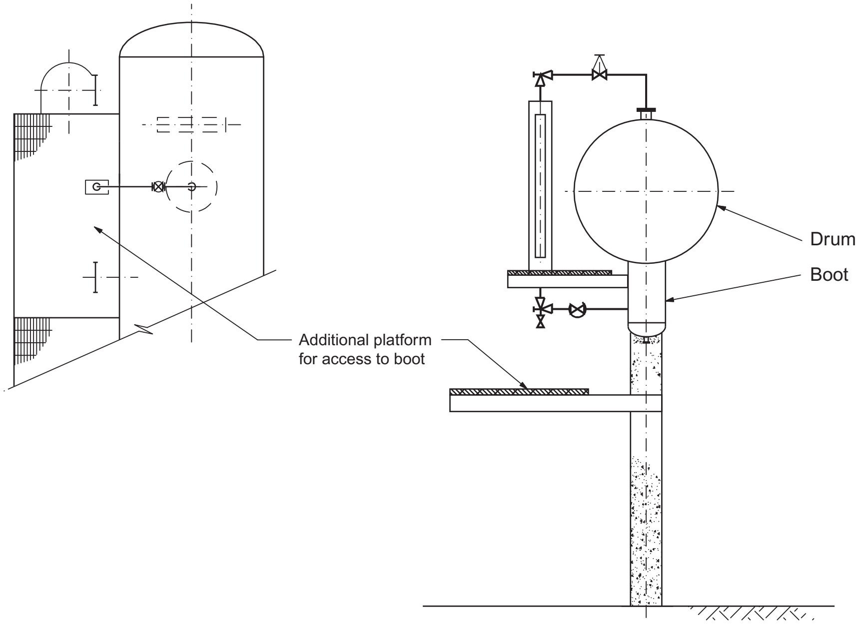
Vessel and drum instrumentation



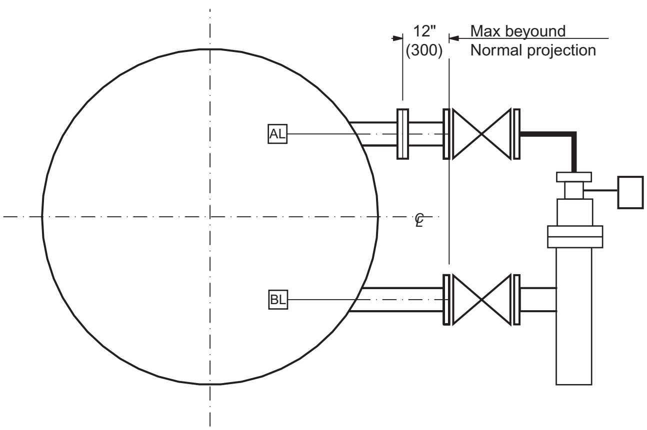
Instrument bridle at horizontal drum

Process may require horizontal drums to be furnished with a small vertical drum called a "boot," which will be attached to the underside of the vessel.

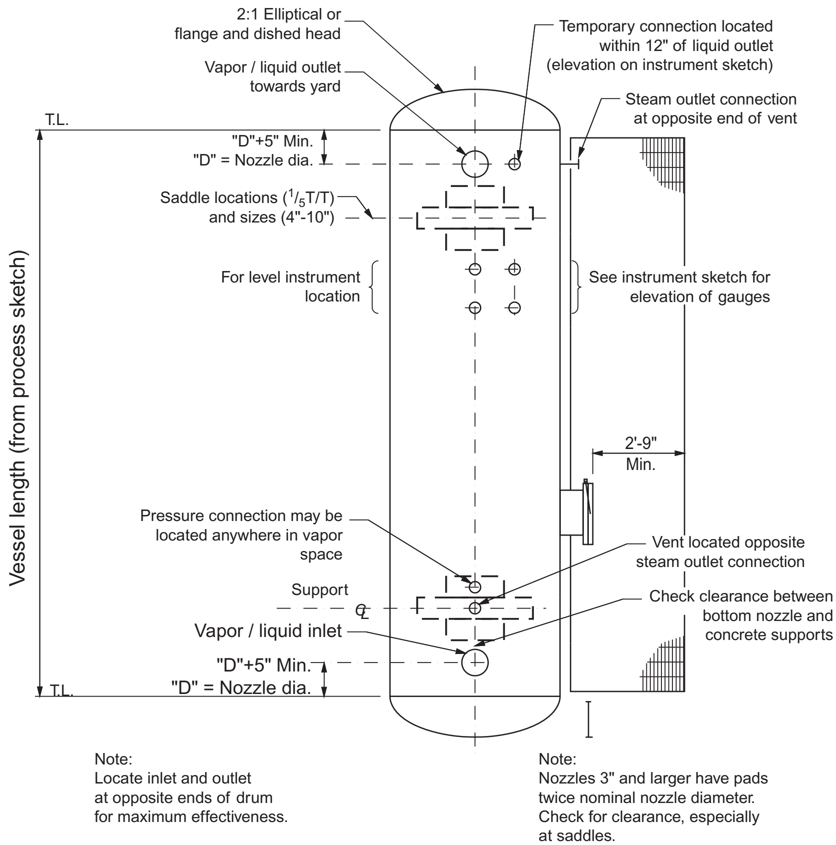
This boot will be inaccessible from the main vessel platforming, so special consideration must be given to the arrangement of additional platforming.



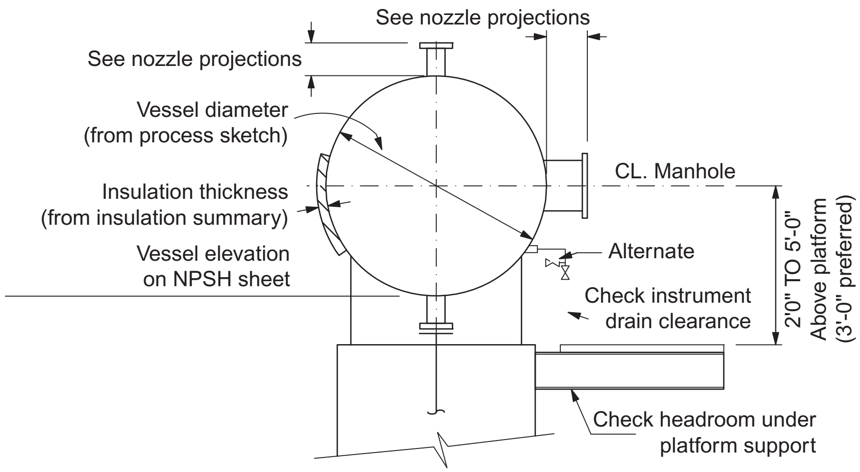
Vessel boot arrangement



Nozzle hillside connections



Typical drum layout



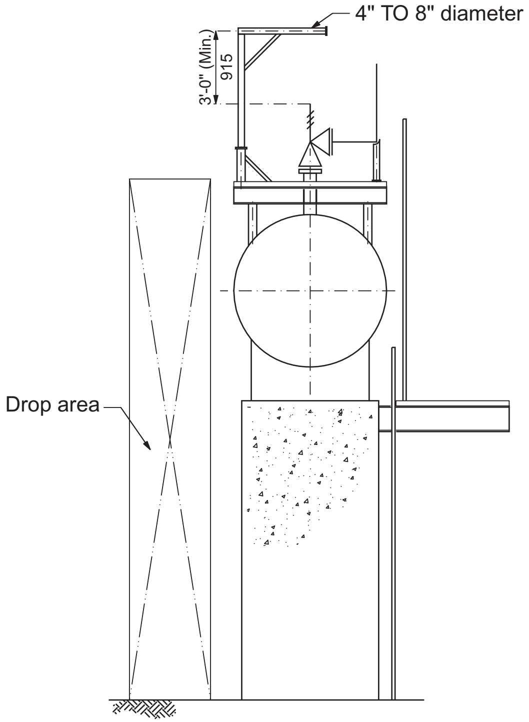
Vessel and drum instrumentation

5.8 MAINTENANCE

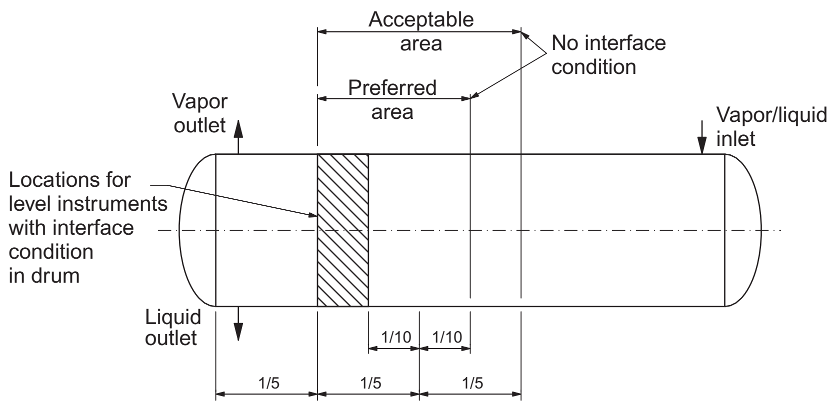
Maintenance of a vessel or drum is limited to the removal of exterior components such as large relief valves and internal mixers.

Davits or mobile equipment can be used to handle these components.

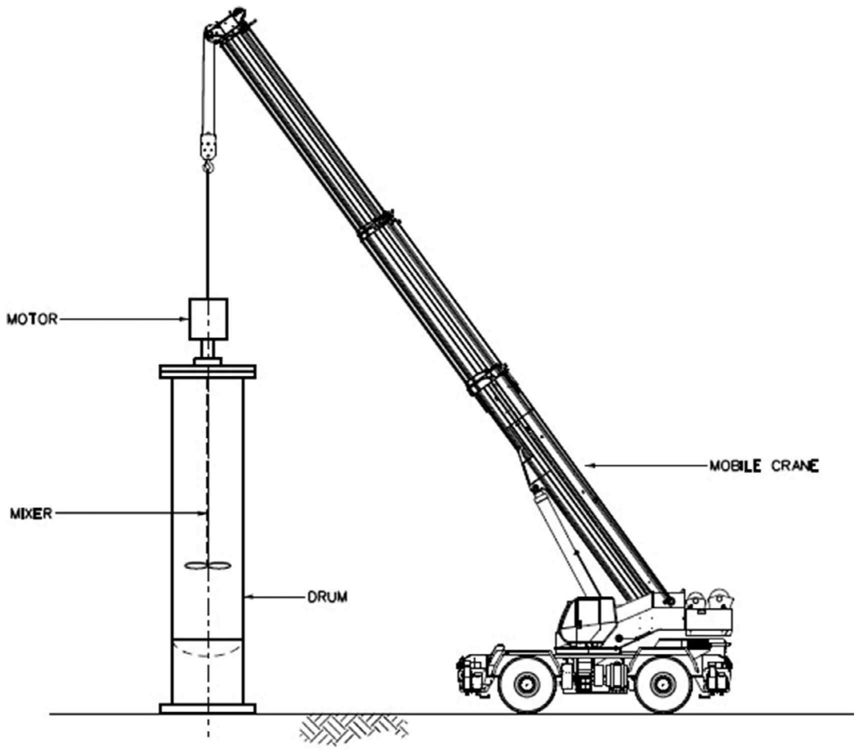
If vessels have internal mixers then enough removal space must be allowed above the vessel and if the vessel is located in a structure then removable platforming should be looked at if required.



Vessel davit



Instrument locations



5.9 CONSIDERATIONS

As well as some vessels having boots, some vessels also might be required to slope for process reasons.

If the vessel is sloped, all the piping from the nozzles must be calculated as the angles will be offset and the required slope required for the piping must be calculated.

It is important for the layout engineer to be familiar with client and company vessel standards.

Before an engineer starts a vessel layout, it is mandatory that all associated disciplines be consulted that is, mechanical, instruments, and process to ensure that all available data requirements are incorporated.

CHAPTER

Exchangers

6

6.1 SELECTION

Because of many variables, selecting optimal heat exchangers can be difficult. Hand calculations can be used, however most times; heat exchangers are selected by the use of computer programs, either by heat exchanger engineers, or by equipment vendors.

To select an appropriate heat exchanger, the engineer (or equipment vendors) would firstly consider the design limitations for each heat exchanger type. Though cost is often the primary criterion, several other selection criteria are important:

- High-/low-pressure limits
- Thermal performance
- Temperature ranges
- Product mix (liquid/liquid, particulates, or high-solids liquid)
- Pressure drops across the exchanger
- Fluid flow capacity
- Clean ability, maintenance, and repair
- Materials required for construction
- Ability and ease of future expansion
- Material selection, such as copper, aluminum, carbon steel, stainless steel, nickel alloys, ceramic, polymer, and titanium.

Choosing the right heat exchanger requires some knowledge of the different heat exchanger types, as well as the environment where the unit must operate. Typically, in the manufacturing industry, several differing types of heat exchangers are used for just one process or system to derive the final product. For example, a kettle heat exchanger for preheating, a double pipe heat exchanger for the "carrier" fluid and a plate and frame heat exchanger for final cooling. With sufficient knowledge of heat exchanger types and operating requirements, an appropriate selection can be made to optimize the process.

6.2 CONSTRUCTION

The most common type of heat exchanger is the shell and tube. These exchangers are constructed from elongated steel cylindrical vessels that contain bundles of parallel tubes. Liquid passes through the inside of the shell cover over the exterior side of the

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00006-0

tubes, and with another liquid passing through the interior of the tubes. This causes the necessary heat exchange between the two liquids. Generally, the heated media will flow up and the cooler media will flow down.

This is the simple physical behavior of any heated or cooled media. This rule is important if in the flowing physical media change takes place while passing through the heat exchanger (evaporation and condensation), where liquid and noncondensing gases pass through the exchanger this rule becomes a preference.

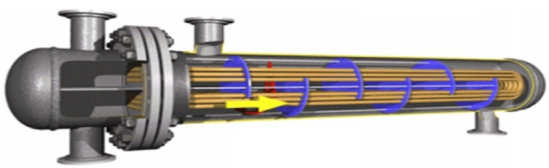
This is why in most cases water inlet is located on the underside of the exchanger, and the outlet on the top side. Similarly, steam would enter at the top channel nozzle and condensate leaving from the bottom outlet.

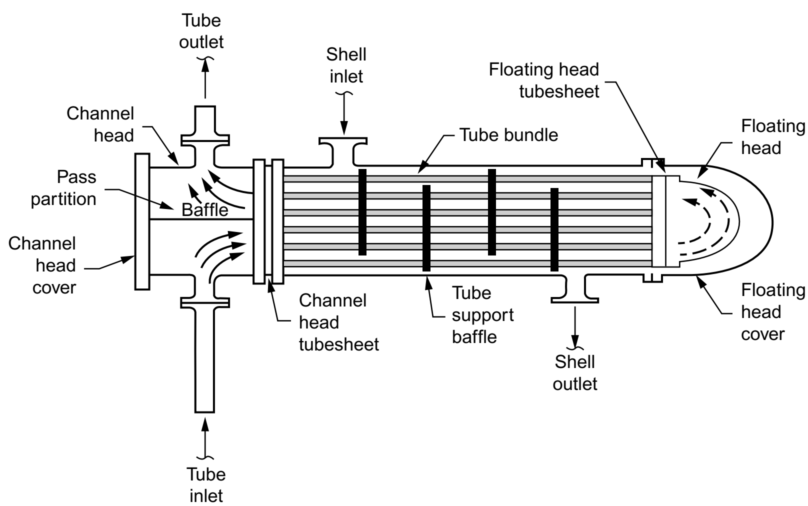
A condenser vapor inlet would be at the top and the liquid outlet would be at the bottom. At the start of exchanger design, the exchanger engineer will define:

- Exchanger type
- Construction details
- Nozzle arrangements
- Flow direction

The exchanger engineer usually has no influence over the external piping arrangement, and conversely the piping engineer and designer usually has no influence over the design of the heat exchanger, but he can request alternate flow and nozzle arrangements based on a more economical and better engineered piping arrangement.

Shell and tube exchangers—These are the most common types of exchanger.





These exchanger heads can be designed to accommodate several passes on the tube side. Multiple passes on the shell side can be achieved by installing baffles parallel to the tubes. Baffles may also be installed inside the shell, perpendicular to the tubes to direct the liquid in the shell against the tubes. Multiple passes are used to increase fluid velocity or to improve flow path, and this increases heat recovery.

Plate exchangers–These are generally used in low-pressure, low-temperature applications.

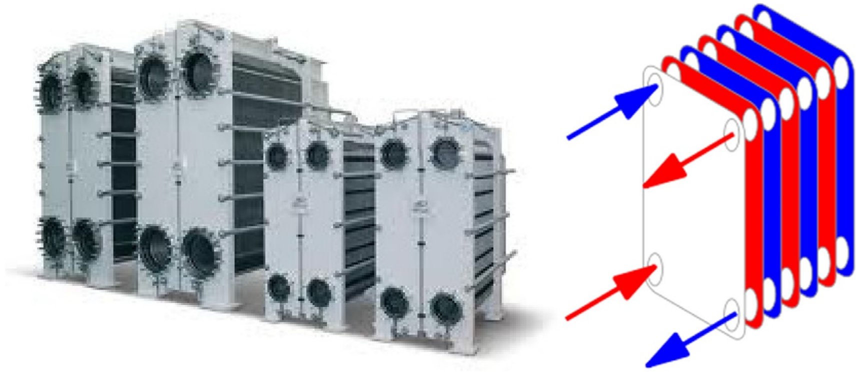
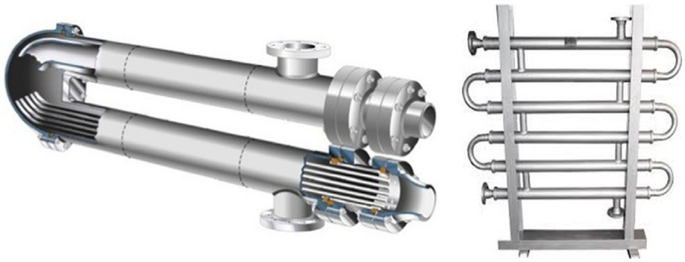


Plate exchangers are made up of end covers that carry bars, inlet, and outlet nozzles, plates, and gaskets. Exchanger plates have spacing between them for liquid flow. A gasket set into channels on the end of each plate directs the liquid flow. Ports for inlet and outlet are stamped into the corners of each plate.

Double pipe exchangers–These are used when one liquid has a greater resistance to heat flow than another or when the surface area is small.

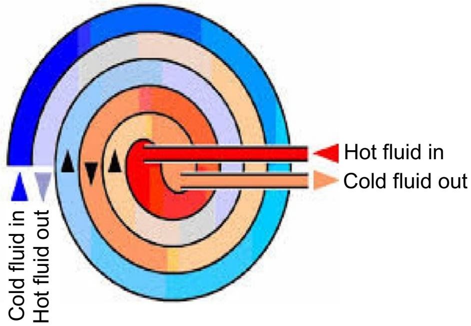


The addition of fins to the inner pipe evens out the resistance to heat flow of the two liquids.

Basically, a double pipe exchanger consists of a pipe within a pipe. Both pipes have a return bend at one end. The inner pipe is fitted with fins. The outer pipe acts as the shell.

Shell nozzles are mounted vertically from the outer pipe. Tube nozzles are directly welded to the inner pipe ends.

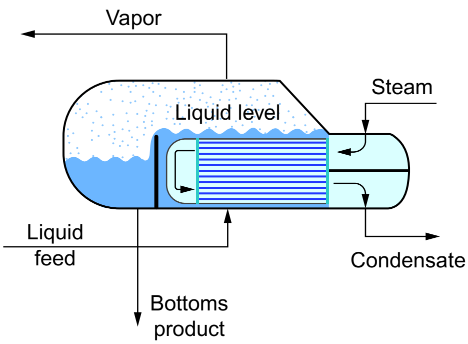
Spiral heat exchangers–These are used generally in chemical plants and are of circular construction.



Spiral heat exchangers consist of an assembly of two long strips of plate wrapped to form a pair of concentric spiral passages. The alternate edges of the passage are closed; this enables the liquid to flow through continuous channels. Removable covers are fitted to each side of the spiral assembly for access to the spiral plate. Inlet and outlet nozzles are integral to the plate housing and covers.

PHASE-CHANGE HEAT EXCHANGERS

In addition to heating up or cooling down fluids in just a single phase, heat exchangers can be used either to heat a liquid to evaporate (or boil) it or used as condensers to cool a vapor and condense it to a liquid. In chemical plants and refineries, reboilers used as heat-incoming feed for distillation towers are often heat exchangers.

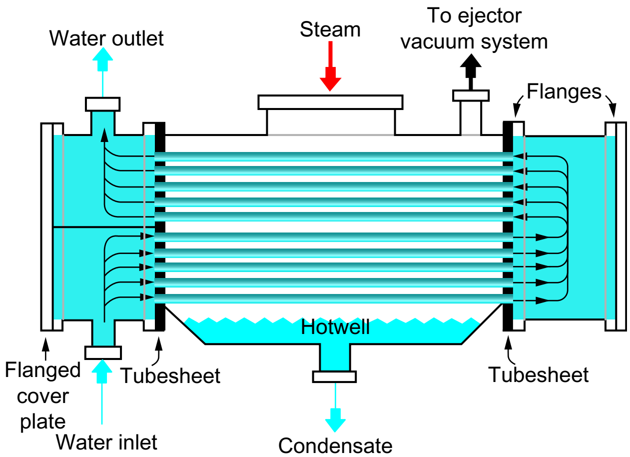


Typical kettle reboiler used for industrial distillation towers

Distillation set-ups typically use condensers to condense distillate vapors back into liquid.

Power plants that use steam-driven turbines commonly use heat exchangers to boil water into steam. Heat exchangers or similar units for producing steam from water are often called boilers or steam generators.

In the nuclear power plants called pressurized water reactors, special large heat exchangers pass heat from the primary (reactor plant) system to the secondary (steam plant) system, producing steam from water in the process. These are called steam generators. All fossil-fueled and nuclear power plants using steam-driven turbines have surface condensers to convert the exhaust steam from the turbines into condensate (water) for re-use.

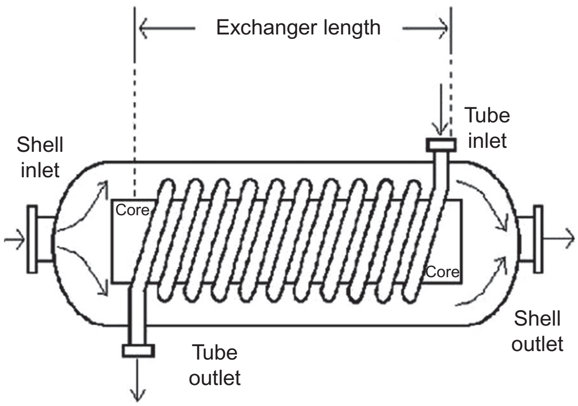


Typical water-cooled surface condenser

To conserve energy and cooling capacity in chemical and other plants, regenerative heat exchangers can transfer heat from a stream that must be cooled to another stream that must be heated, such as distillate cooling and reboiler feed preheating.

HELICAL-COIL HEAT EXCHANGERS

Helical-coil heat exchanger sketch, which consists of a shell, core, and tubes.



Helical-coil heat exchanger

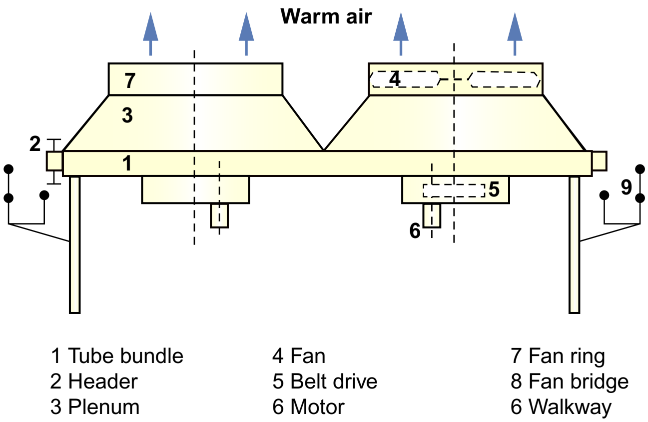
Although double-pipe heat exchangers are the simplest to design, the better choice in the following cases would be the helical-coil heat exchanger (HCHE).

The main advantage of the HCHE, like that for the SHE, is its highly efficient use of space, especially when its limited and not enough straight pipes can be laid. Under conditions of low flowrates (or laminar flow), such as the typical shell-and-tube exchangers that have low heat-transfer coefficients becomes uneconomical when there is low pressure in one of the fluids, usually from accumulated pressure drops in other process equipment.

When one of the fluids has components in multiple phases (solids, liquids, and gases), which tends to create mechanical problems during operations, such as plugging of small-diameter tubes. Cleaning of helical coils for these multiple-phase fluids can prove to be more difficult than its shell-and-tube counterpart; however, the helical-coil unit would require cleaning less often.

These have been used in the nuclear industry as a method for exchanging heat in a sodium system for large liquid metal fast breeder reactors since the early 1970s,

Air cooled exchangers–These are different from other exchangers in that the cooling agent used is air instead of liquid.



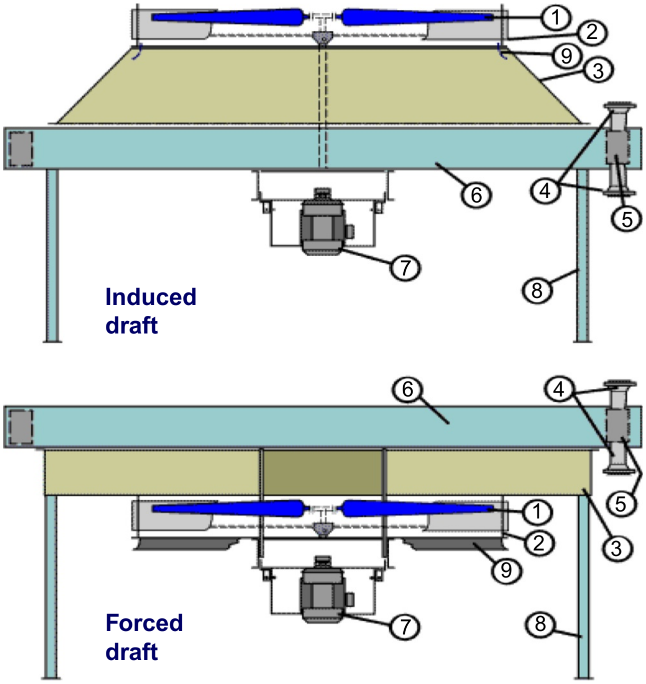
An air cooler consists of fin tube bundles, with a header box attached to each end, and this is supported horizontally by a steel frame or structure.

There are two types of air-cooled exchangers:

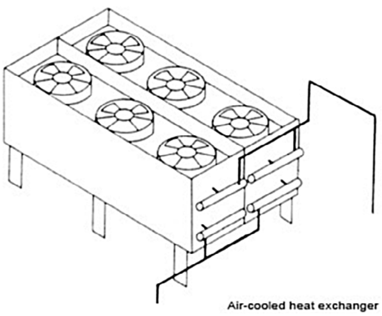
- **Single pass**–These have the inlet nozzles mounted on top of the header box, with the outlet nozzles at the opposite end mounted on the bottom of the header box.
- **Double pass**–These have the outlet nozzles located at the same end as the inlet nozzles, so for additional surface area, more passes can be added, or additional units can be installed and located side by side.

In an air-cooled exchanger, air circulates by multiblade propeller type fans.

These provide either **forced** or **induced** drafts. These fans can be supplied with either adjustable, speed, or variable pitch blades. The fan blade pitch can be changed to vary the air flow to compensate for the rise or fall in air temperatures.



1. Fan
2. Fan ring
3. Plenum
4. Nozzle
5. Header
6. Tube bundle
7. Drive assembly
8. Column support
9. Inlet bell



Piping at Inlet / Outlet Manifold

Inlet Outlet manifold and tube ends

Photo of air cooler on a pipe rack in a process plant

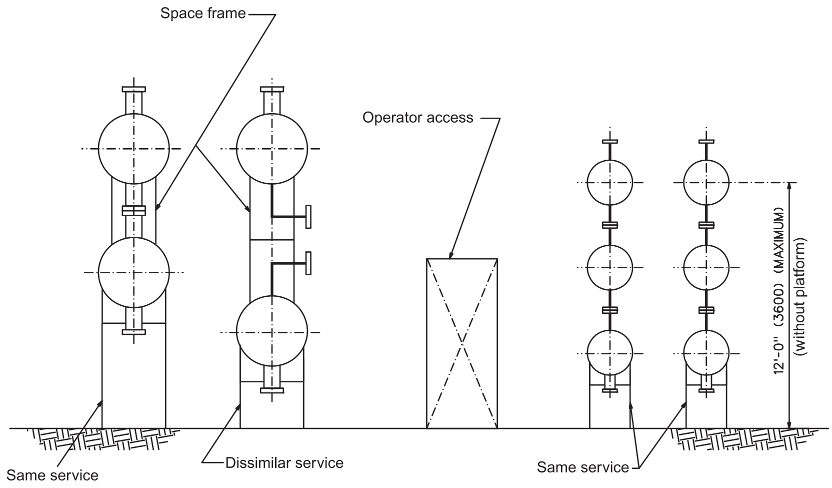
6.3 LOCATION AND SUPPORT

Exchangers are located within a process unit to satisfy the following conditions:

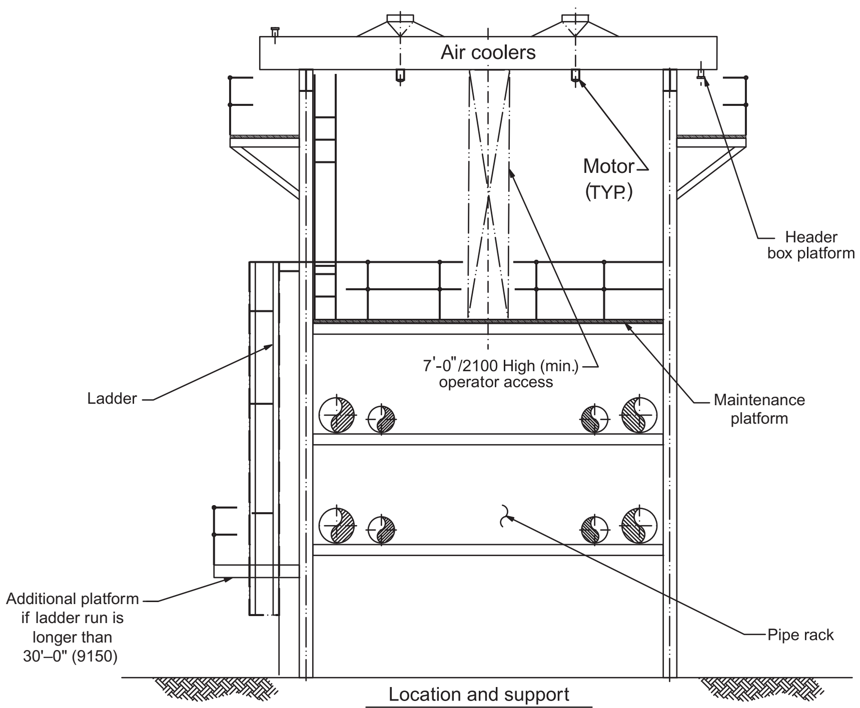
- Must be close to related equipment
- Should have an economic piping arrangement
- Shall have adequate piping flexibility
- Must provide good operator and maintenance access
- Shall provide a safe egress

The type of exchanger can also influence location:

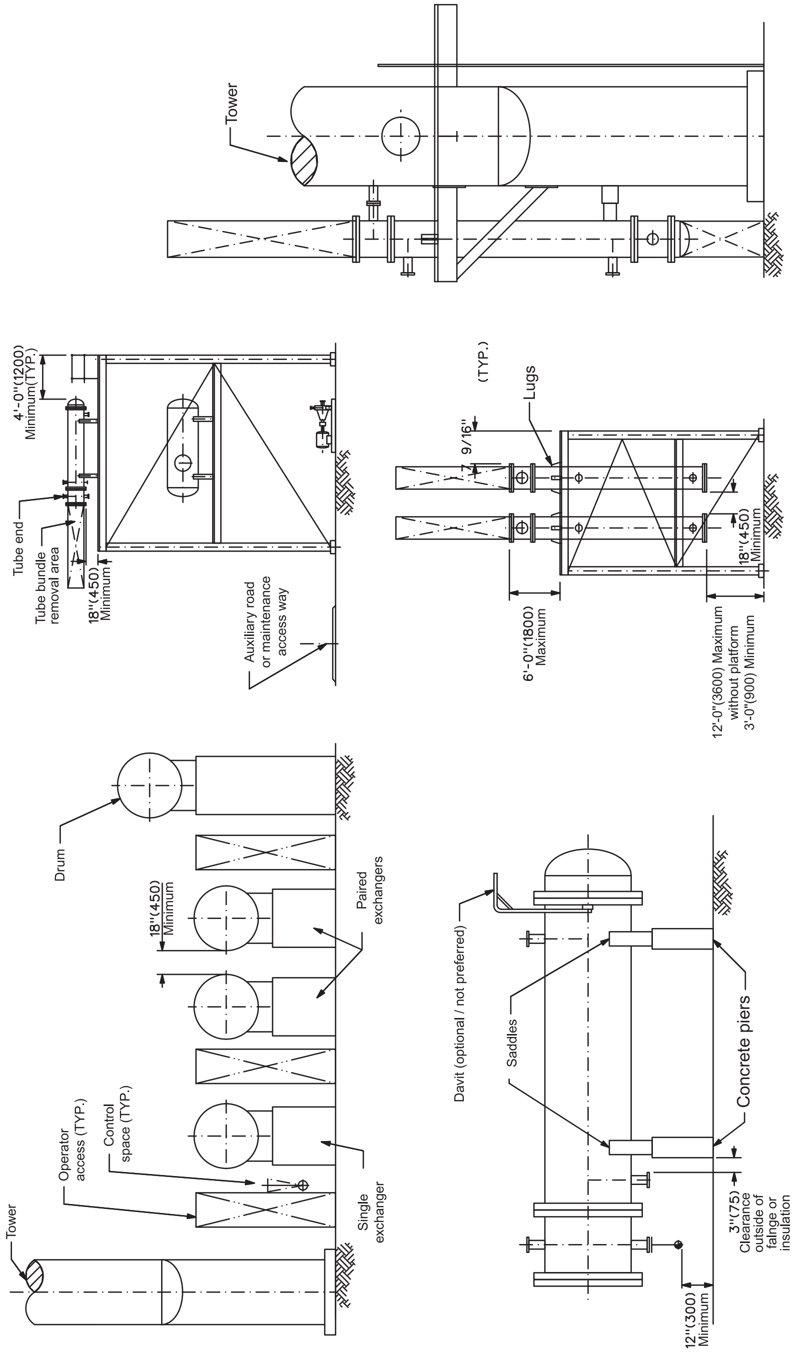
Air coolers–are usually located above pipe racks, but can also be located at grade in a small structure (more common in gas plants).
Vertical reboilers–are usually attached to vertical columns (towers).
Shell-and-tube exchangers–most often are located at grade singularly or in groups, but can also be in a structure.
Spiral exchangers–either located at grade or structure, usually close to associated equipment due to process considerations.
Plate exchangers–can also be located at grade or in structures.
Stacked exchangers–the maximum elevation for stacked exchangers is 12 ft/ 3.6 m. Above this height platforming and structure may be required.
Double pipe–can also be located at grade or in structures.



Shell and tube exchangers-stacked



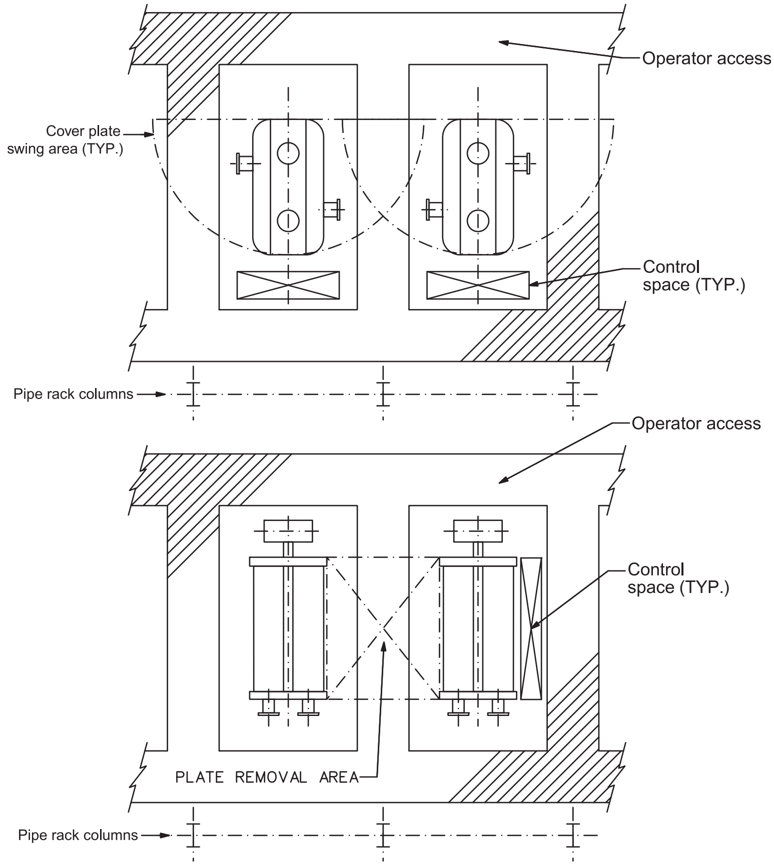
Location and support



Location and support

Horizontal exchangers are supported by saddles attached to concrete piers at grade, or by saddles sitting on structural support steel in steel structures.

Space is required on spiral exchangers in order to swing the cover plates open.



Location and support

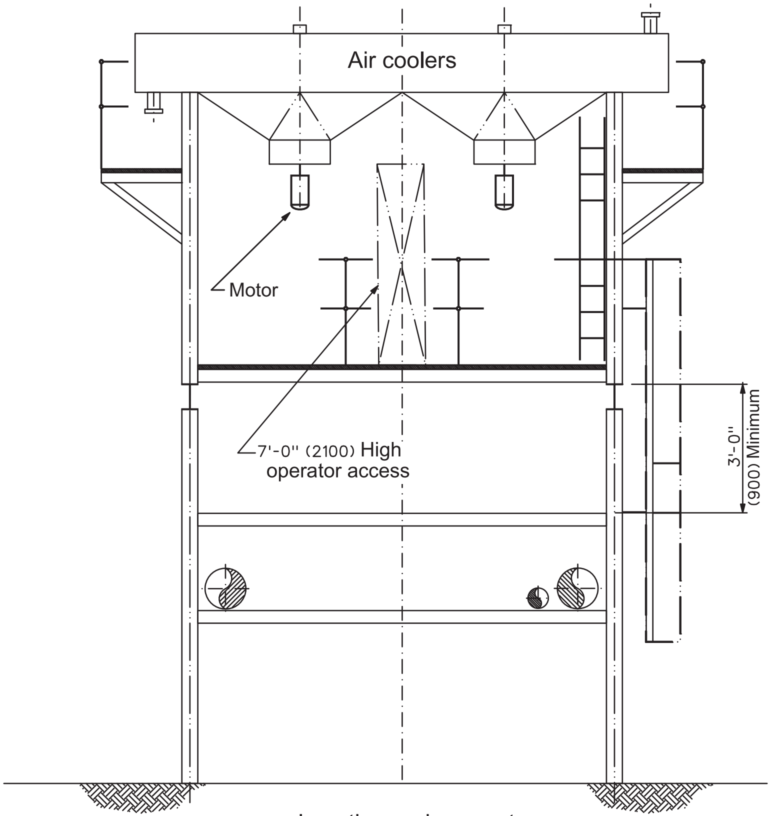
Space is required at plate exchangers to remove the individual plates.

Spiral and **plate exchangers** can operate either in series or in parallel. Owing to the configuration and maintenance requirements the preference is to locate them as single items.

AIR COOLERS

Design considerations must consider the point of support, such as the supporting column. Considerations for changes to platforms and pipe support loadings that might occur late in the project, and must be addressed so as to avoid delays by the changes to the air cooler arrangement by the vendor.

Late changes need to be avoided to avoid redesign to support legs and platforms, as this will only incur delays and added costs.



Location and supports

6.4 NOZZLE ORIENTATION

Location and orientation of exchanger nozzles affects the piping configurations of exchangers. Although the piping engineer does not set the nozzle locations (this is set by the exchanger engineer), the piping engineer has the ability to suggest alternate nozzle locations in the interests of an improved and more economical piping arrangement.

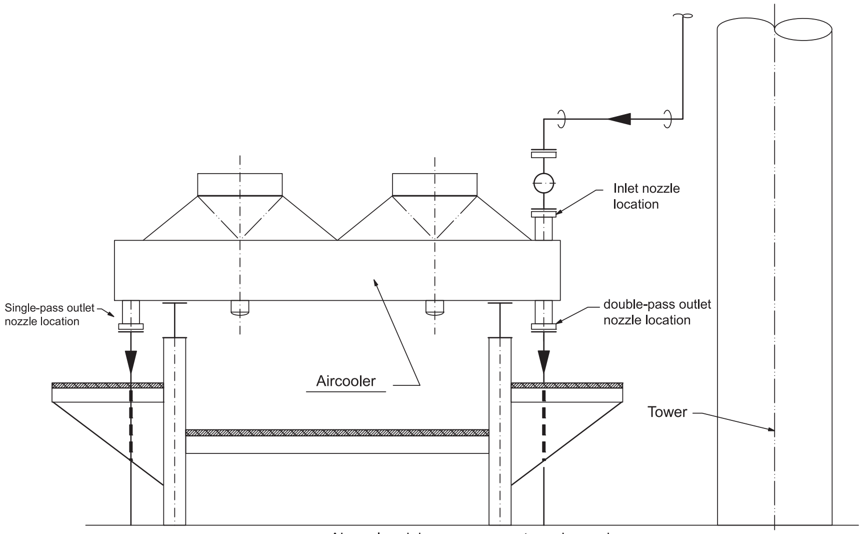
Stacked exchangers can be reduced in height by using elbow or gooseneck nozzles.

Air cooler nozzle locations can affect piping arrangements.

Single pass arrangements can make return piping on an overhead condenser very long, and might also increase the height of the air cooler.

Double pass arrangements (or reorienting the air cooler) can improve the piping configuration.

6.5 EXCHANGER PIPING



Air cooler piping arrangement on pipe rack

Piping at exchangers must be arranged in such a manner that it is:

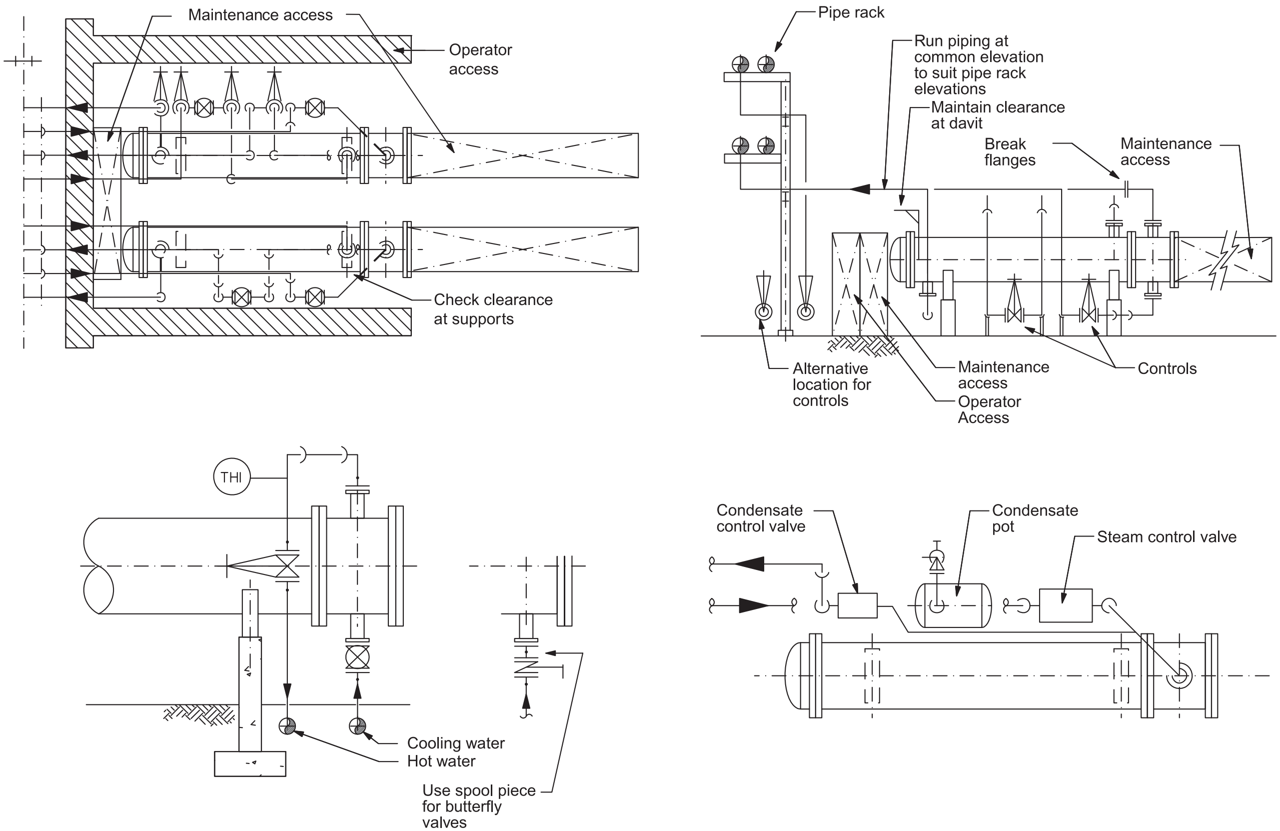
- Economical
- Flexible
- Adequately supported
- Maintainable
- Operable
- Has good access and egress
- Allows for adequate space for removal of channel heads and shell covers.
- Adequate space adjacent to exchanger for location of control stations if required.

Piping connected to **channel head nozzles** should be furnished with break flanges, to enable the removal of the channel head.

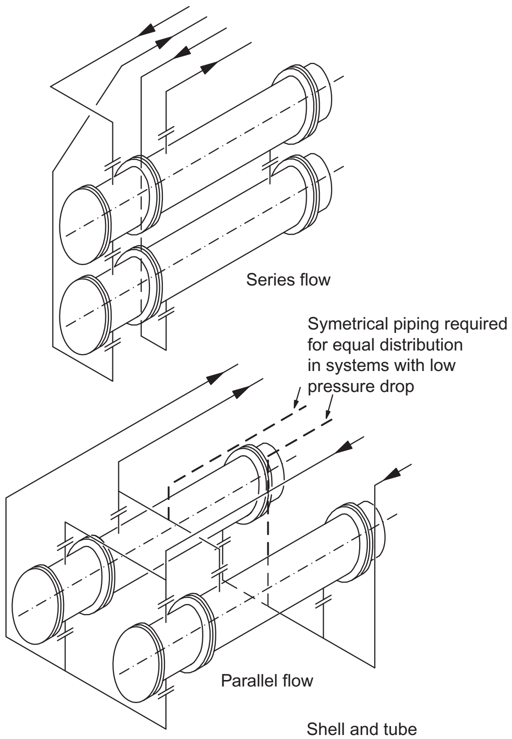
Piping connected to s**piral** and **plate exchangers** must be positioned so as to allow opening of covers and plate removal.

Piping connected to cover plate nozzles of **spiral exchangers** must be furnished with break flanges to allow for plate removal.

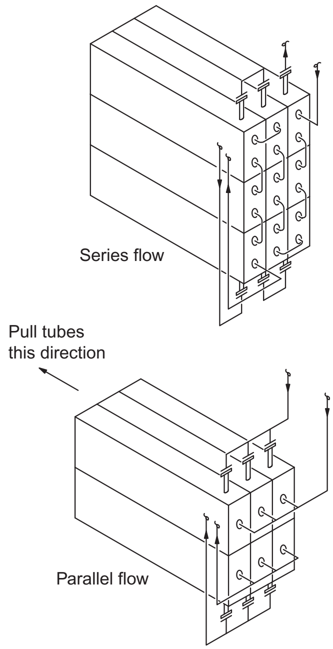
Piping connected to **air coolers** should not be routed over tube banks or fans, and should also be kept clear of motor maintenance access spaces.



Piping arrangements at exchangers.

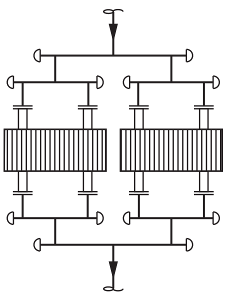


Shell and tube

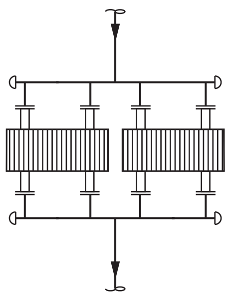


Double pipe exchanger

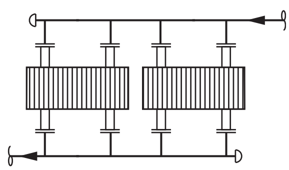
AIR COOLER PIPING



Cascade



Symmetrical rake



Asymmetrical rake

6.6 TYPES OF EXCHANGERS

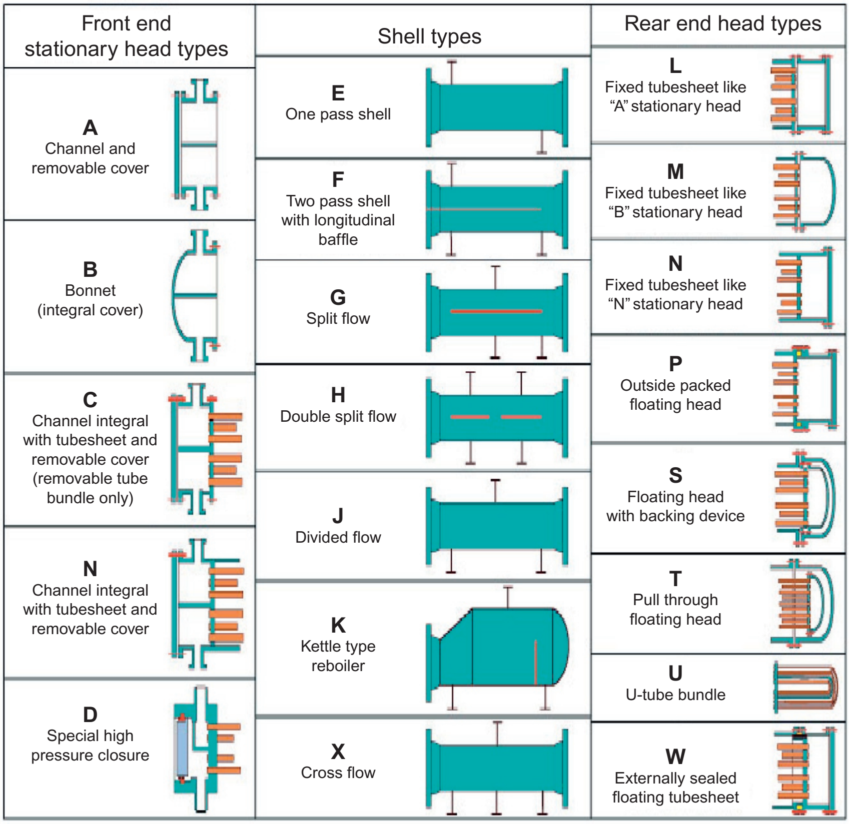
The Tubular Exchanger Manufacturers Association, Inc. (TEMA) is trade association of leading manufacturers of shell-and-tube heat exchangers, who have pioneered the research and development of heat exchangers for over 60 years.

The TEMA standards and software have achieved worldwide acceptance as the authority on shell-and-tube heat exchanger mechanical design.

TEMA has also developed engineering software that complements the TEMA standards in the areas of flexible shell elements (expansion joints) analysis, flow-induced vibration analysis, and fixed tube sheet design and analysis. This state-of-the-art software features a materials data bank of 38 materials, as well as user-friendly, interactive input and output screens. The programs handle many complex calculations, so users can focus on the final results.

The following is a chart of TEMA standard types:

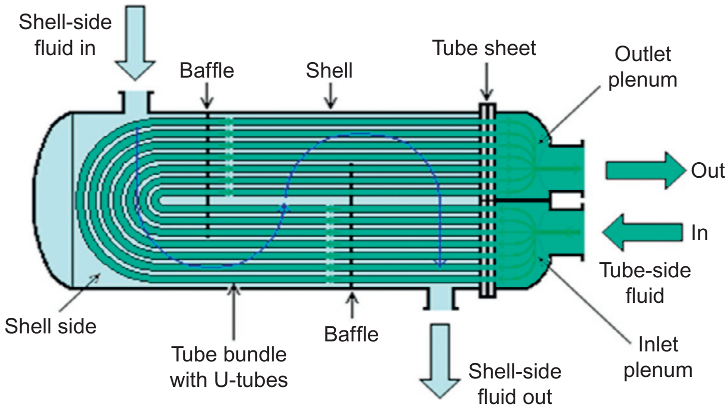
TEMA–type

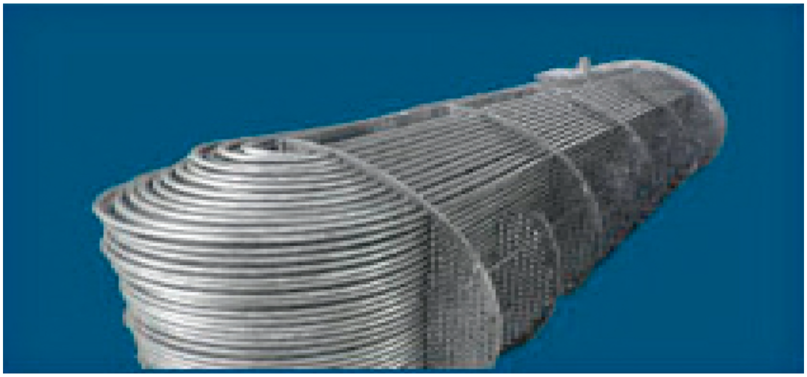


SHELL-AND-TUBE HEAT EXCHANGER

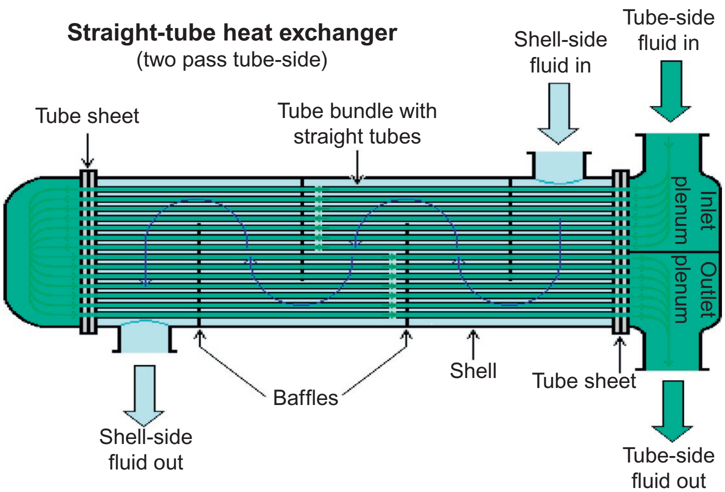
Tube bundles

U-tube heat exchanger





Tube bundles



Tube bundles

MAINTENANCE

Shell-and-tube exchangers–internal shell and tubes can be cleaned in place with high-pressure steam or water, and by "rodding". If the exchanger is designed for tube removal, then the tubes can be removed for repair or cleaning. Tube bundles and both the head-and-shell covers can be removed by the use of fixed handling devices such as davits, hitch points, and pulling posts. Fixed structures with trolley beams, traveling Gantry cranes, and cranes with hydraulic bundle extractors can also be used.

Plate and frame heat exchangers can be disassembled and cleaned periodically. Tubular heat exchangers can be cleaned by such methods as acid cleaning, sandblasting, high-pressure water jet, bullet cleaning, or drill rods.

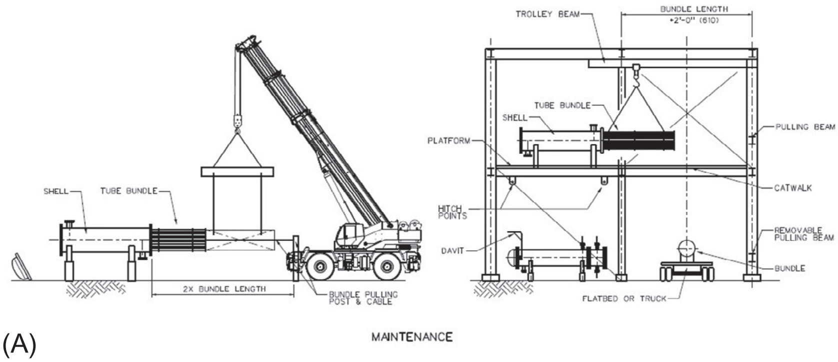
In large-scale cooling water systems for heat exchangers, water treatment such as purification, addition of chemicals, and testing is used to minimize fouling of the heat exchange equipment. Other water treatment is also used in steam systems for power plants, etc. to minimize fouling and corrosion of the heat exchange and other equipment.

A variety of companies has started using water-borne oscillations technology to prevent biofouling. Without the use of chemicals, this type of technology has helped in providing a low-pressure drop in heat exchangers.

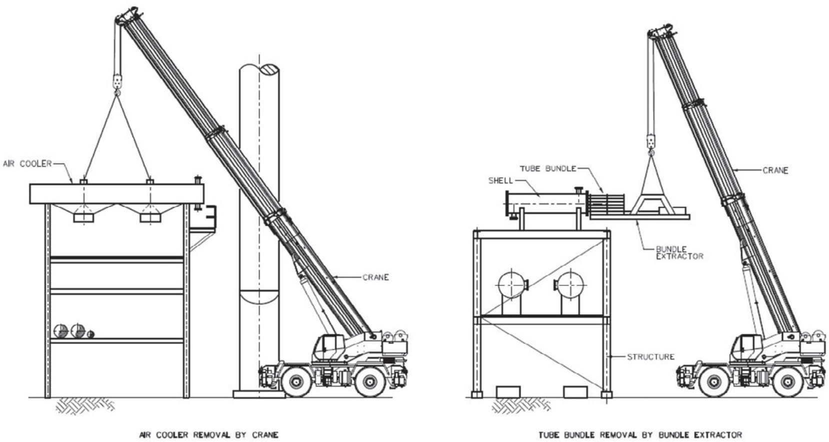
By periodically calculating the overall heat transfer coefficient from exchanger flow rates and temperatures, the owner of the heat exchanger can estimate when cleaning the heat exchanger is economically attractive.

Integrity inspection of plate and tubular heat exchanger can be tested in situ by the conductivity or helium gas methods. These methods confirm the integrity of the plates or tubes to prevent any cross contamination and the condition of the gaskets.

Mechanical integrity monitoring of heat exchanger tubes may be conducted through nondestructive methods such as eddy current testing.



(A)



(B) Sectional views through Process Plant Structures and Piperack showing exchanger Bundle removal

CHAPTER

Pumps

7

7.1 PUMP TERMINOLOGY

NPSH

NPSH stands for Net Positive Suction Head, and is one of the most important terms used in relationship to pumps.

NPSH is the measure of the pressure drop of a liquid between the pump inlet and the pump impeller.

NPSH is determined by testing by the pump manufacturer.

NPSH required for the pump is expressed as “feet of water/m of water” by the pump manufacturer.

VAPOR PRESSURE

When the vapor pressure at the pump suction falls below the vapor pressure of the liquid, the liquid “Flashes,” that is, it changes to vapor.

Pumps are designed to pump liquid only and not vapor, so when the liquid flashes, there is no liquid flow to the pump and the pump is said to be “Vapor Bound.”

It is therefore important to make sure that the pump is full of liquid and not air. To achieve this, correct NPSH for the pump must be used. Therefore, the engineer must choose the correct NPSH as given by the pump manufacturer to determine the correct pump to use for the applicable application.

ALLOWABLE NOZZLE LOADINGS

The maximum **allowable nozzle loadings** are the stresses that a pump suction and discharge nozzle can withstand (as set by the pump manufacturer, client, and code).

It is the responsibility of the **piping engineer** and **designer** to produce a flexible piping layout to minimize nozzle stresses, and the **pipe stress engineer** to check these stresses by use of computer programs such as Caesar II, and advise the **piping engineer and designer** if changes in layout are required to minimize these stresses.

The Engineer’s Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00007-2

7.2 NPSH (NET POSITIVE SUCTION HEAD)

Let us look at how to determine the NPSH.

Available NPSH:

$$\begin{aligned}\text{NPSH(available)} &= \text{net pressure(vessel pressure + static head)}\\ &\quad - \text{liquid vapor pressure + frictional losses}\end{aligned}$$

$$\text{NPSH}_\text{a} = \frac{(p_\text{a} - p_\text{v} + p_\text{n})}{p}$$

where NPSH_a = NPSH available, p_a = atmospheric pressure, p_v = vapor pressure, p_n = gage pressure at the pump suction p = density.

Important considerations are to maintain equipment heights and minimize pump suction piping so that the NPSH is greater than the required NPSH.

Insufficient NPSH reduces pump capacity and efficiency, and this can lead to cavitation damage to the pump.

CAVITATION

The term cavitation is used a lot when referring to pumping systems. This is the sudden collapse of the vapor bubbles.

Cavitation can result in:

- a loss of head and capacity
- severe erosion of the impeller and casing surfaces in the inlet areas
- noise

API (American Petroleum Institute) has set standards for pumps.

The **American Petroleum Institute** (**API**) is the largest US Trade Association for the oil and natural gas industry. It claims to represent about 400 corporations involved in production, refinement, distribution, and many other aspects of the petroleum industry.

The association's chief functions on behalf of the industry include advocacy and negotiation with governmental, legal, and regulatory agencies; research into economic, toxicological, and environmental effects; establishment and certification of industry standards; and education outreach. API both funds and conducts research related to many aspects of the petroleum industry.

When we refer to an **API** pump we are referring to a "**horizontal single stage**" pump as used in the petroleum industry.

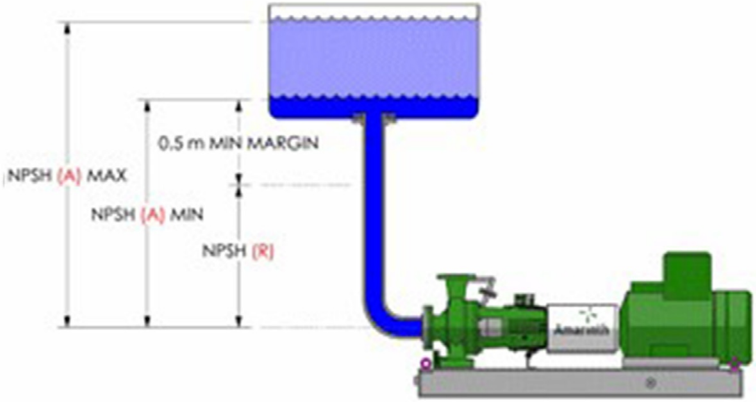
API 610–refers to "**Centrifugal Pumps**" for **General Refinery service**, and is the standard used for the design and purchase of petroleum pumps.

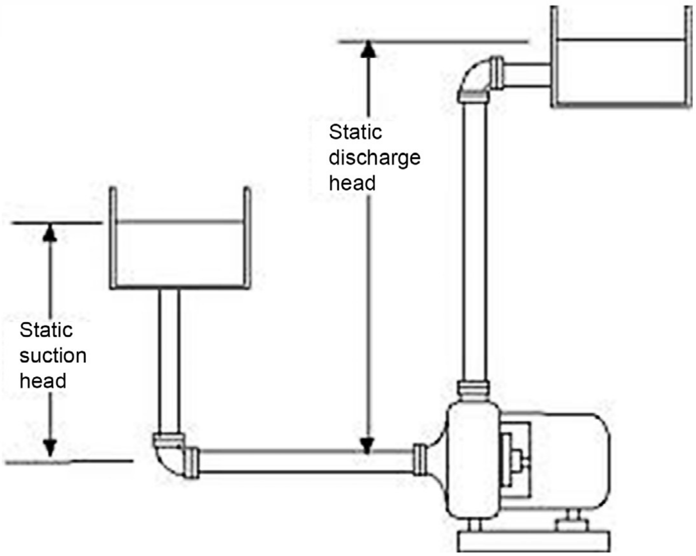
AVS (American Voluntary Standard Pumps)–this is a standard developed by the Hydraulic Institute USA.

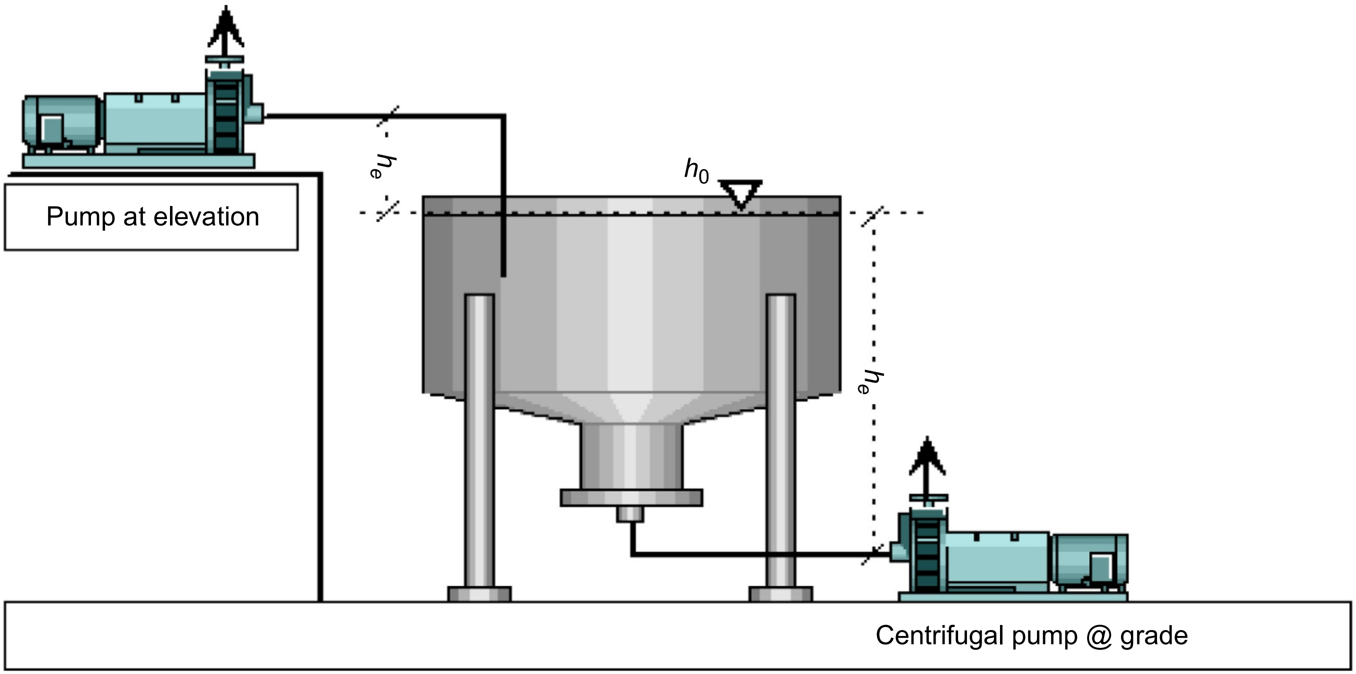
The **AVS** standards outline standard pump dimensions that enable designers to establish pump outline dimensions and baseplate foundations.

These standards are interchangeable for each size, are used by all the pump manufactures.

NPSH



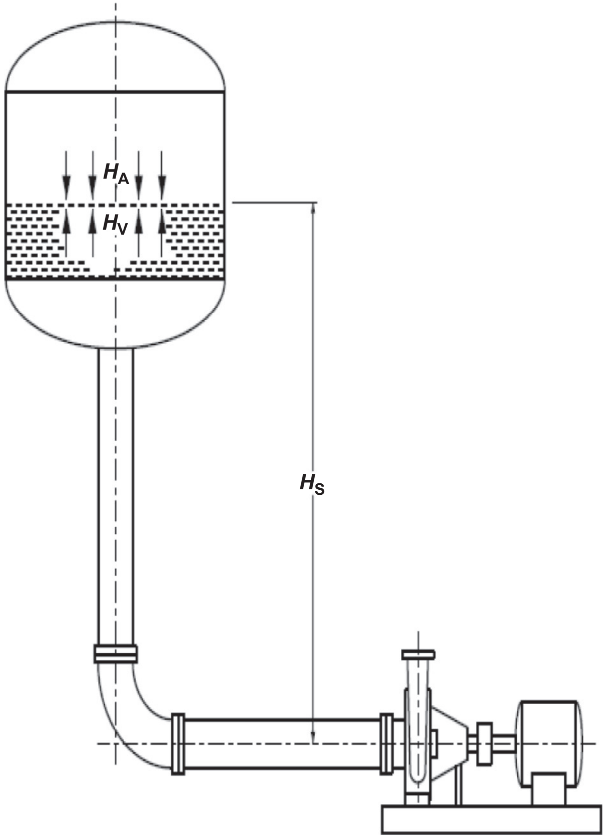




h_e
h_0
Pump at elevation
h_e
Centrifugal pump @ grade

Horizontal run of piping. Together they represent the loss in the total available suction head from the tank to the pump suction.

The distance DE represents the vapor pressure of the liquid, thus the NPSHA is represented by the distance CD. From the chart the basic equation for net positive suction head available is:



$$\mathbf{NPSHA} = \pm H_S - h_L + H_A - H_V$$

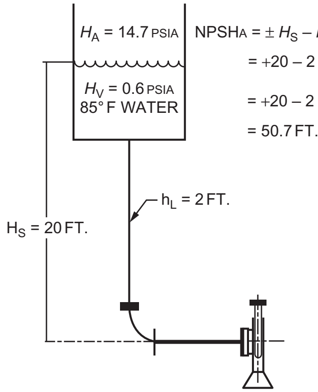
Where,

H_S = static suction head (+) or lift (–)

h_L = suction line losses (friction, entrance and fittings) in feet.

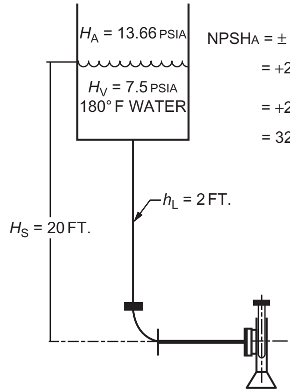
H_A = absolute pressure at the liquids free surface in feet of liquid pumped.

H_V = vapor pressure of liquid at pumping temperature converted to feet of liquid handled.



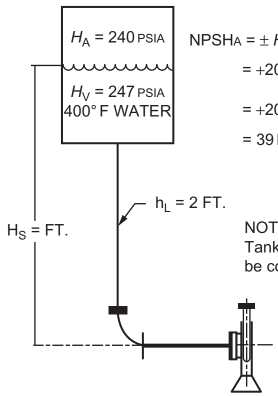
$$NPSH_A = \pm H_S - h_L + H_A - H_V$$
$$= +20 - 2 + \frac{(14.7 \times 2.31)}{0.997} \frac{(0.6 \times 2.31)}{0.997}$$
$$= +20 - 2 + 34.1 - 1.4$$
$$= 50.7\ \text{FT.}$$

Open tank at sea level



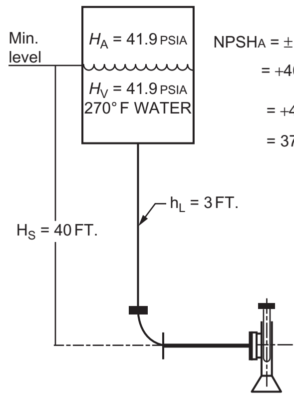
$$NPSH_A = \pm H_S - h_L + H_A - H_V$$
$$= +20 - 2 + \frac{(13.66 \times 2.31)}{0.97} \frac{(7.5 \times 2.31)}{0.97}$$
$$= +20 - 2 + 32.5 - 17.9$$
$$= 32.6\ \text{FT.}$$

Open tank at 2000 ft (609.6 m)



$$NPSH_A = \pm H_S - h_L + H_A - H_V$$
$$= +20 - 2 + \frac{(240 + 14.7 \times 2.31)}{0.86} \frac{(247 \times 2.31)}{0.86}$$
$$= +20 - 2 + 684 - 663$$
$$= 39\ \text{FT.}$$

NOTE:
Tank pressure of 240 PSIG must be converted to PSIA.



$$NPSH_A = \pm H_S - h_L + H_A - H_V$$
$$= +40 - 3 + \frac{(41.9 \times 2.31)}{0.933} - \frac{(41.9 \times 2.31)}{0.933}$$
$$= +40 - 3 + 103.8 - 103.8$$
$$= 37\ \text{FT. Min.}$$

7.3 PUMP TYPES

CENTRIFUGAL PUMPS

Inline process pump

Vertical sump pump

Horizontal split case—double suction pump

PUMP TYPES

There are basically two types of industry standard pumps and those are "**ANSI**" and "**API**" that are used in the petro-chemical, oil, and gas industries.

Chemical process pumps (ANSI)–these are used in chemicals and corrosive service.

ANSI (American National Standards Institute) Pumps

- The "**ANSI**" pump is designed and built to the *dimensional standards* of the **American National Standards Institute**. Over the years, the **ANSI** pump has become the preferred style of end suction pumps, not only for chemical process applications, but also for water and other less aggressive services. The standard provides for dimensional interchangeability of pumps from one manufacturer to another.

API (American Petroleum Institute) Pumps

- The **API** pump meets the requirements of the "**American Petroleum Institute Standard 610 for General Refinery Service**." This style is almost the exclusive choice for applications in the oil refinery industry, where it handles higher temperature and pressure applications of a more aggressive nature that are common in the refineries.

SERVICE CONSIDERATIONS

In both the chemical and petrochemical industries, many of the liquids being pumped require more consideration than merely environmental damage and pumping efficiency and reliability. It is necessary to consider the aspect of personal safety. Therefore, the choice between the ANSI pump and the API pump must take into account the specific fluid properties as well as the operating conditions.

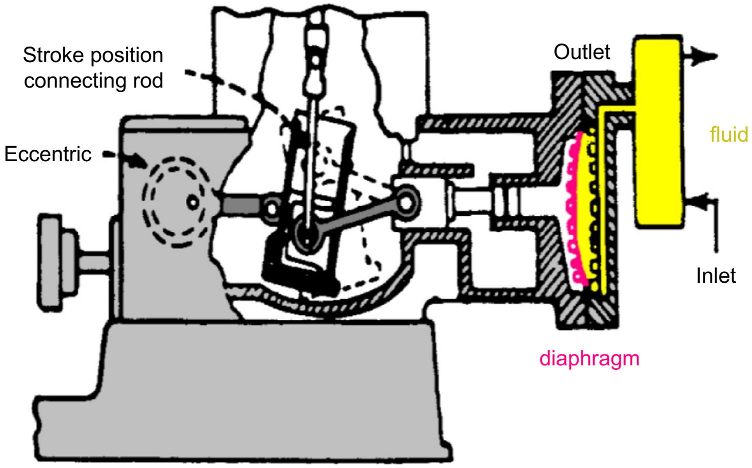
One of the main differences between these choices is predominantly a result of the differences in casing design ratings which are as follows:

- ANSI pump rating = 300 psig at 300°F
- API pump rating = 750 psig at 500°F

In view of these figures, it is apparent that the API pumps should be considered for higher pressure and temperature services than the lighter duty ANSI pump.

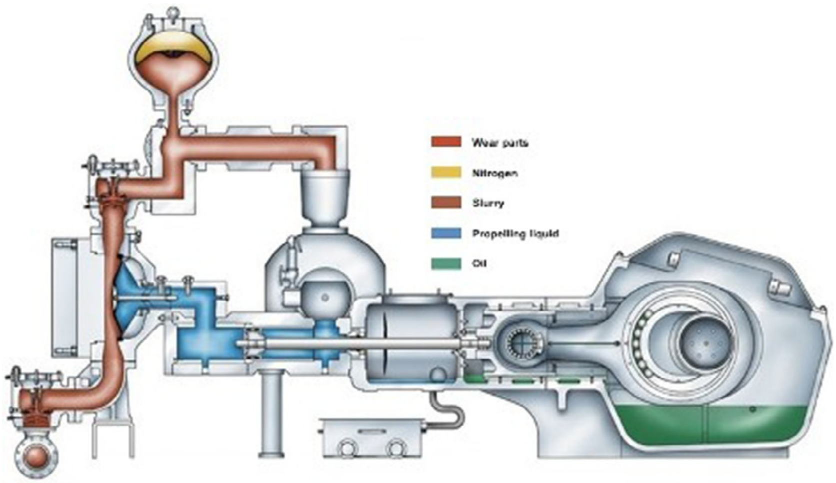
RECIPROCATING (POSITIVE DISPLACEMENT) PUMPS

A reciprocating pump utilizes a crankshaft-connecting rod mechanism identical to internal combustion engines. The crankshaft-connecting rod mechanism converts the rotary movement of the crankshaft to a reciprocating linear movement of plungers or pistons. The plunger/piston movement creates volume changes. As a cavity opens when a plunger/piston retracts, the fluid is admitted through an inlet check valve. When the plunger/piston reverses, the inlet check plunger/piston extends. The outlet check valve opens and the fluid is forced out by the plunger/piston. The discharge volume is fixed for each crankshaft revolution, regardless of the fluid being pumped. Pressure is determined by the system flow resistance and pump construction speed reduction is needed for decreasing high speed from the driver to low pump shaft speed.

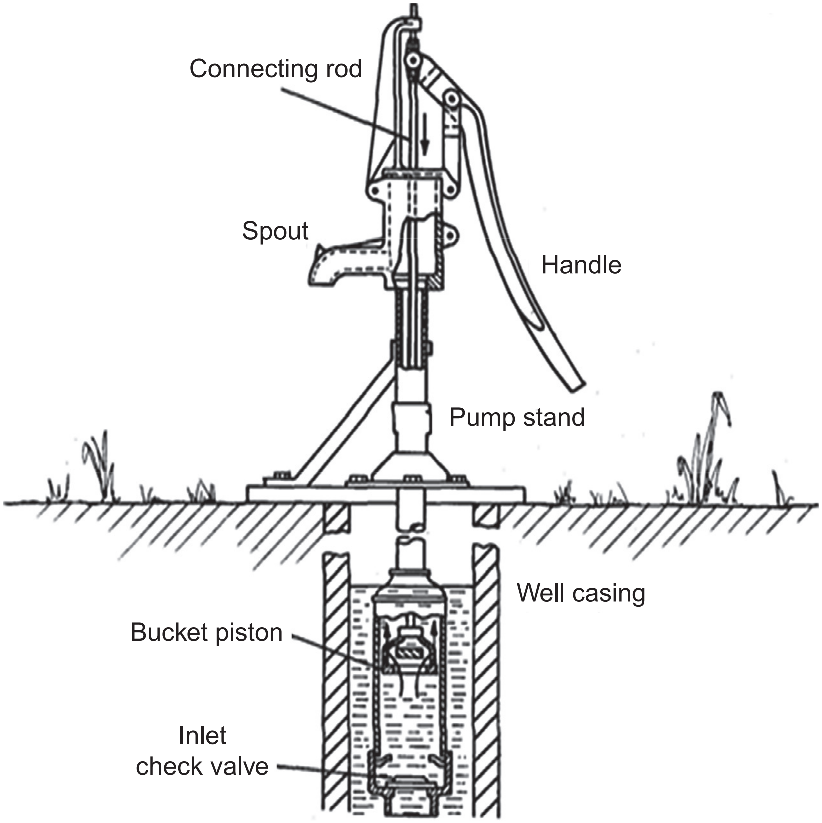


Reciprocating (positive displacement pump)

Single action-plunger pump–(very high pressures/moderate flows/high efficiency).

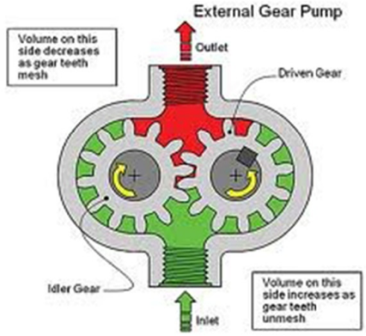


Slurry Pump

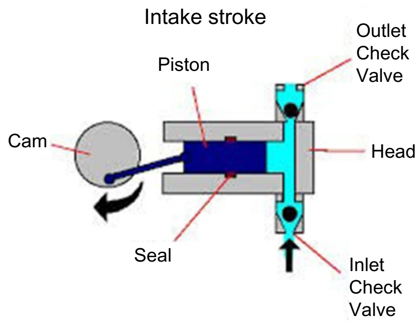


Water lifting pump

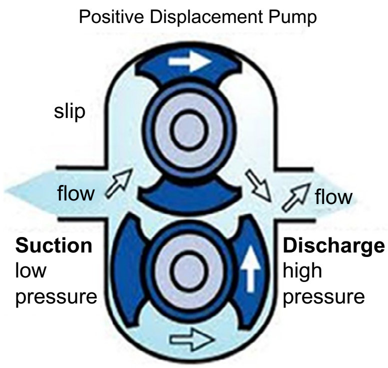
ROTARY PUMPS



Gear pump

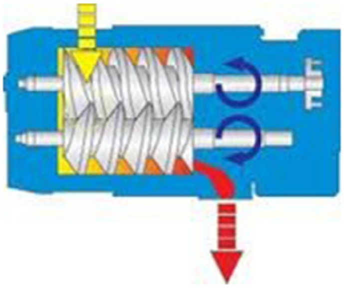


Cam and piston



Two-lobe pump

Single-Screw Pump



Two-screw pump

Rotary pumps are generally used for viscous liquids that do not have hard or abrasive solids in the solution.

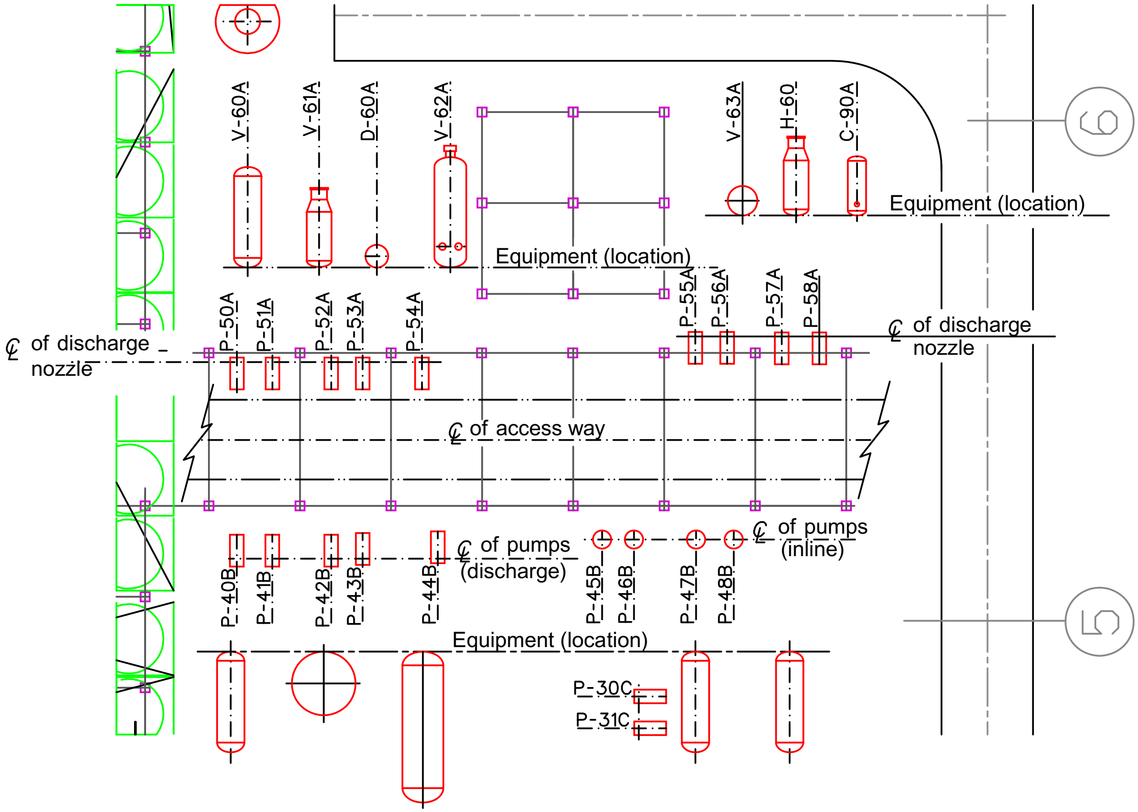
The rotary pump pushes the liquid by the use of vanes, cams, or gears inside the pump casing. The liquid is discharged in a smooth flow, they have no suction or discharge valves.

Rotary pumps can produce a constant volume against variable discharge pressures.

These types of pumps can be more common in petro-chemical plants.

7.4 LOCATION OF PUMPS

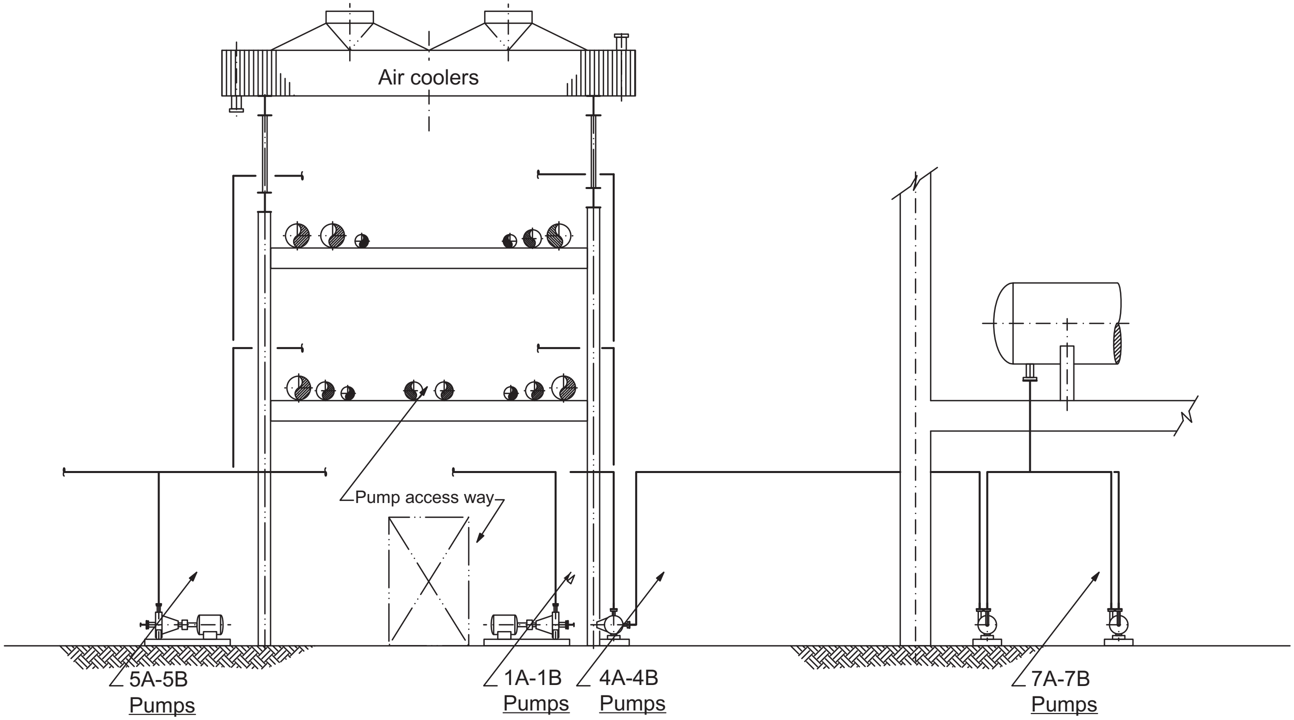
The prime importance of setting the location of a pump is to minimize the length of the suction piping, whilst satisfying both the flexibility requirements of the piping and nozzle loadings.



Location of pumps

When setting the location of pumps on a plot plan, the pump will be located by identifying the following parameters:

- Centerline of pump discharge
- POS (point of support) @ bottom of baseplate
- Centerline of pump suction



Location of pumps

Discharge piping to pipe racks should rise 2′/6 m from column lines.

When hydrocarbon spills are likely pumps should be located outside the pipe rack.

In structures, pumps might be located directly under the equipment they serve.

- Pumps in **hydrocarbon service** should not be positioned under the inlet/outlet nozzles of air coolers.

Vertical pumps are used when using a horizontal pump is not practical due to the available pump head. The fact that the majority of the pump is located below ground gains you the added pump head, vertical pumps should allow for vertical removal of pump.

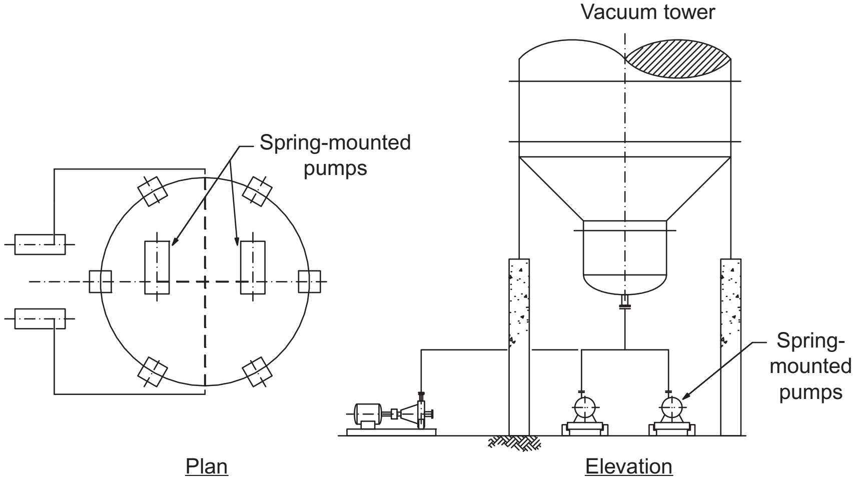
Sump pumps are located in a pit below ground and used for waste removal such as ground spills and rainwater, a screen at the bottom of the pump suction reduces the possibility of fouling.

Sump pumps should have the discharge nozzle flange located above ground.

Boiler feed pumps should be located as close as possible to the deaerator that they draw their water from, because they operate close to the vapor pressure of the liquid.

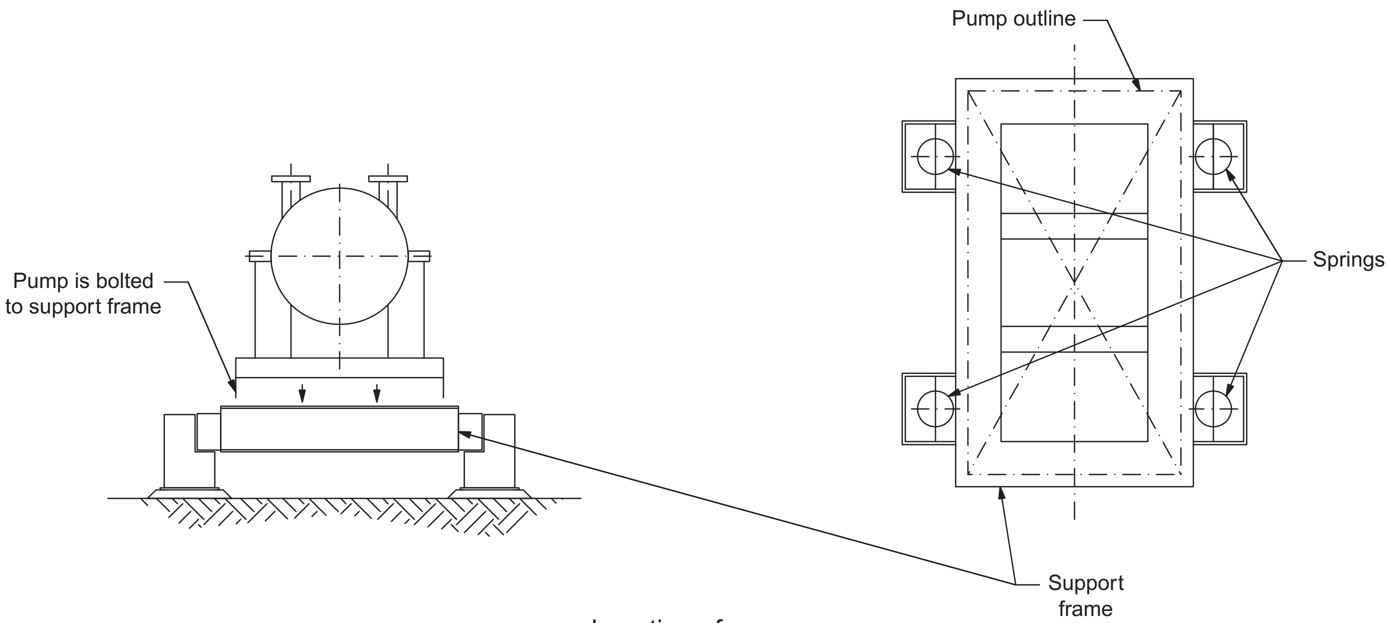
- Centrifugal pumps are the most common type of pump used

Centrifugal pumps used in ***vacuum service*** operate at negative pressures and high temperatures, and these must be located directly under the tower it is serving or just outside the structure.



When **centrifugal pumps** used in ***vacuum service*** are located under the tower, it may be necessary to support the pump with springs.

This allows the pump to move in a vertical direction which reduces the stress and loads on the nozzles.



Location of pumps

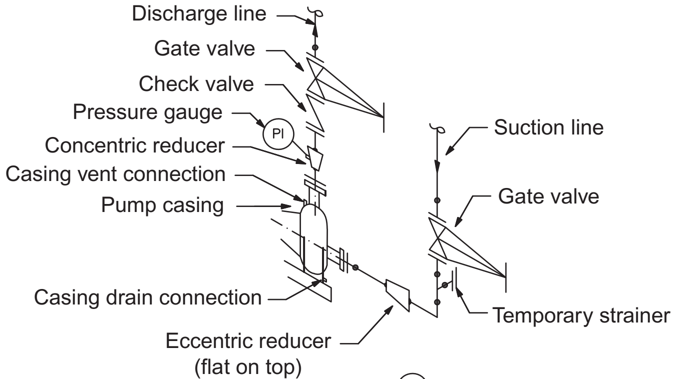
7.5 PUMP PIPING

A pump suction line has a shut off valve and a temporary strainer installed to catch any foreign debris that might have collected during construction.

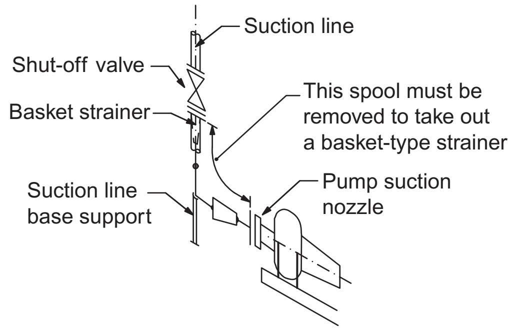
There are various types of temporary strainers used such as tee, basket, conical (often known as Witches Hat), and Y-type. These are removed after start up and a pipe spool put back in line to replace the strainer location.

Pump layouts require many considerations:

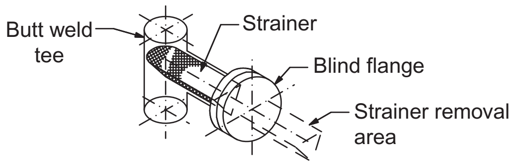
- Location to associated equipment
- Piping flexibility, nozzle loadings (API-610)
- Pipe supports
- Maintenance and operational access
- Duplication and uniformity of pump piping for multiple pumps
- Pump discharge arrangement



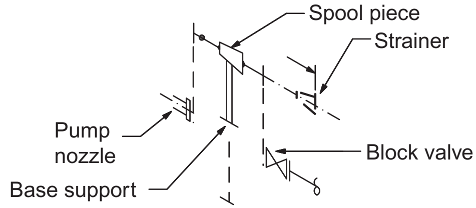
Temporary strainer



Conical strainer

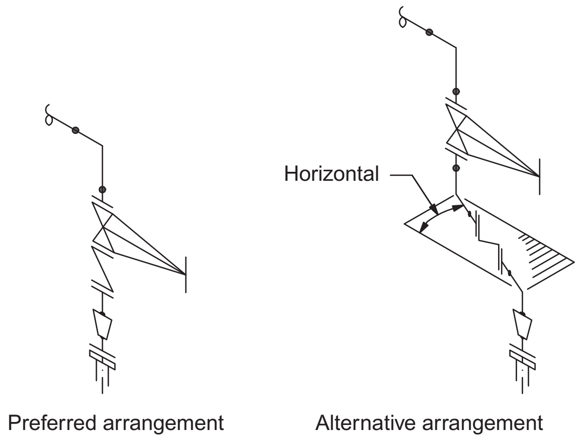


Temporary basket strainer in tee

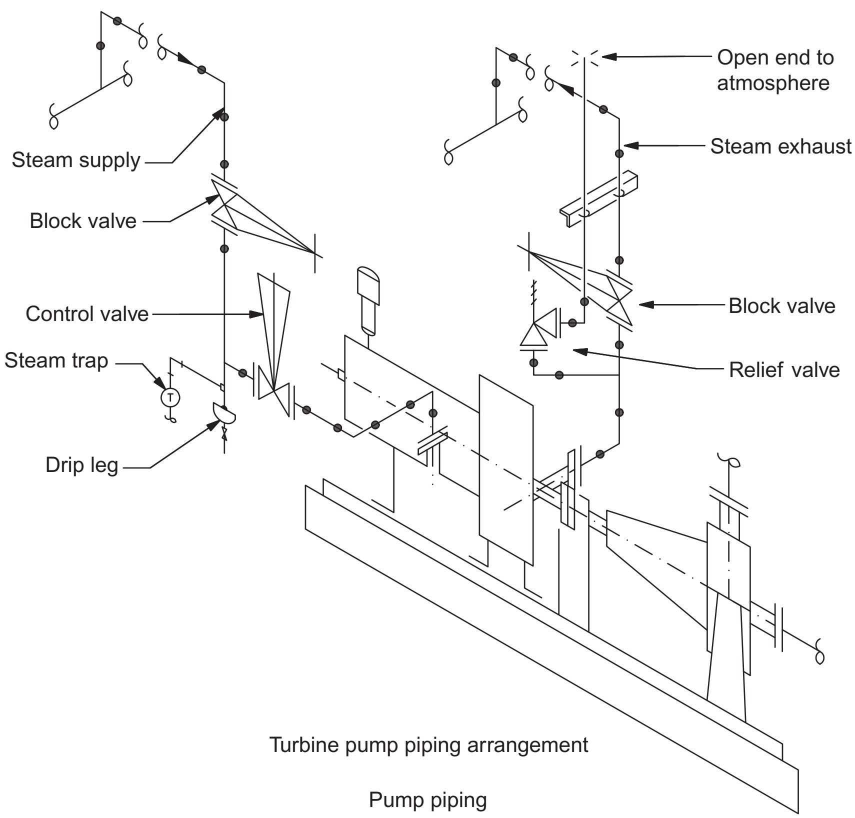


Spool piece

Pump piping

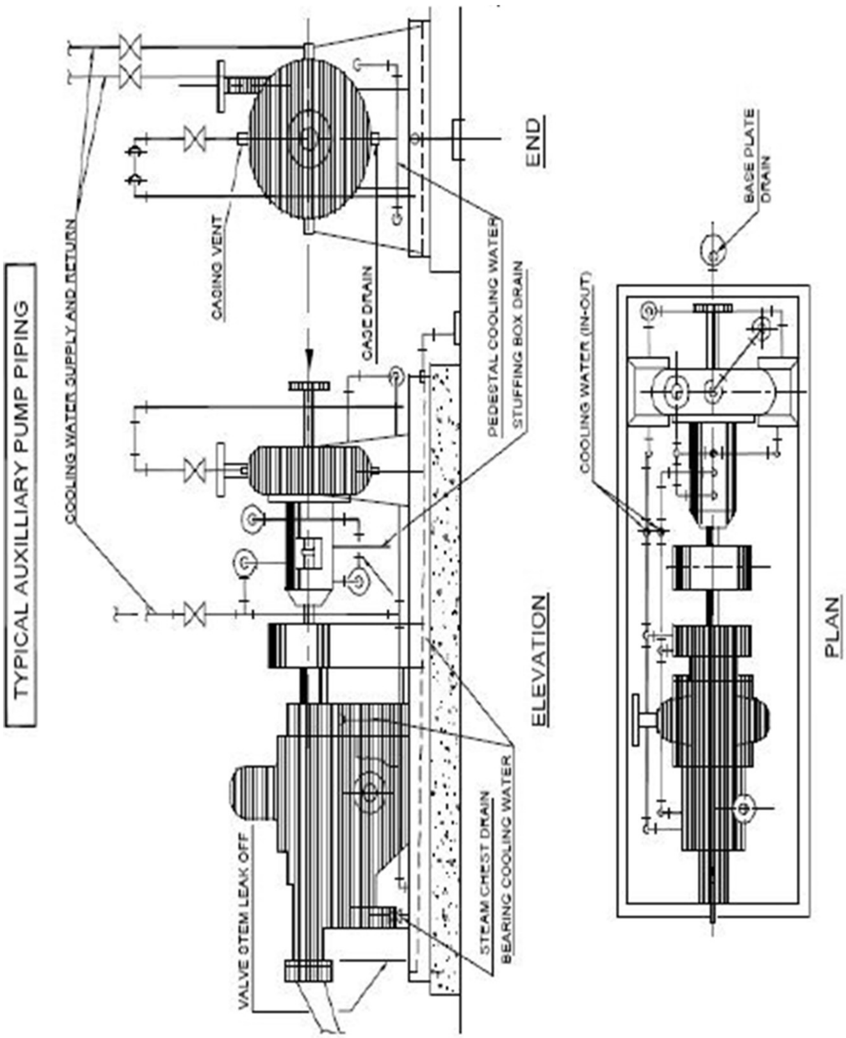


Pump piping



Turbine pump piping arrangement

Pump piping

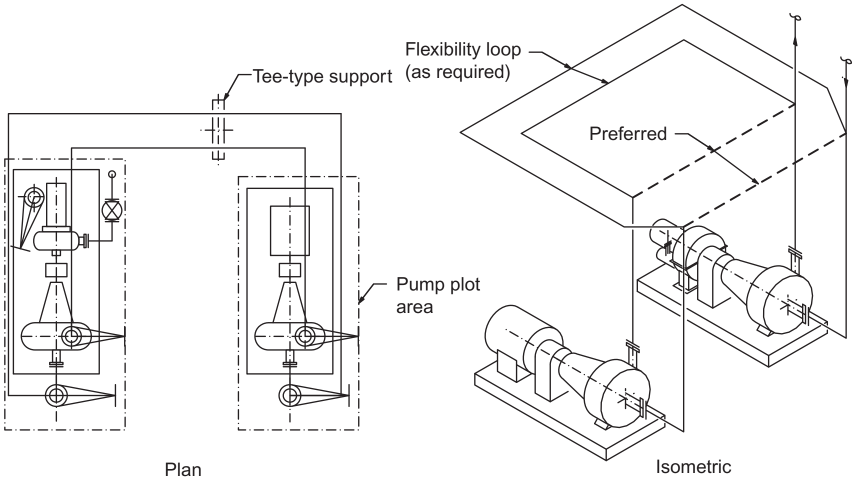

TYPICAL AUXILLIARY PUMP PIPING
COOLING WATER SUPPLY AND RETURN
CASING VENT
CASE DRAIN
PEDESTAL COOLING WATER
STUFFING BOX DRAIN
END
ELEVATION
VALVE STEM LEAK OFF
STEAM CHEST DRAIN
BEARING COOLING WATER
COOLING WATER (IN-OUT)
BASE PLATE
DRAIN
PLAN

7.6 PUMP PIPING SUPPORTS

Pump discharge piping arrangements.

Pump discharge piping not only needs to be operable, but also flexible.

To enable flexibility, discharge piping can be arranged as shown.



Pump piping supports

CHAPTER

Compressors

8

8.1 DEFINITION, COMPRESSOR TYPES AND DRIVES

Compressors are used to increase the pressure of a gas.

This happens by mechanically reducing the volume of gas inside the compressor casing, this is done by compression.

The most frequently compressed gas is “Air”.

Other gases commonly compressed are:

- Oxygen
- Natural gas (LPG & LNG)
- Nitrogen

The most common types of compressors used in process facilities and pipeline compressor stations are:

- Positive displacement
- Centrifugal
- Axial

Compressors handle large volumes of gas and they use a variety of drives:

- Electric motor drives
- Steam turbines
- Gas turbines

The two most common types of compressors are:

- Centrifugal
- Reciprocating (positive displacement)

Centrifugal compressors can be:

- Single stage
- Multistage

Centrifugal compressors use high-speed impellers that increase the kinetic energy of the gas, and convert the energy produced into a higher pressure inside the divergent outlet passage (diffuser).

Large volumes of gas can be compressed to moderate pressures in **Centrifugal** compressors.

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00008-4

Reciprocating (positive displacement) compressors can be:

- Single stage
- Multistage

Reciprocating (piston type) is the only type that can compress gas to extremely high pressures.

8.2 AUXILIARY EQUIPMENT

Both **Centrifugal** and **Reciprocating** compressors require auxiliary equipment to support their operation.

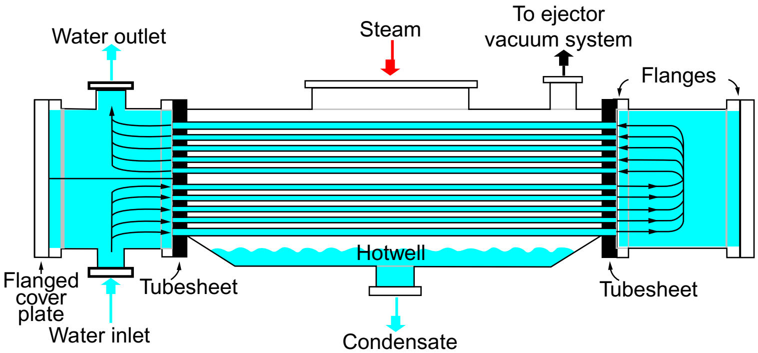
Lube oil consoles—are used to supply lubricating oil to the compressor bearings.

Lube oil consoles—can either be standalone units or mounted directly to the compressor frame.

Seal oil consoles—supply lubricating oil to the hydraulic seals which are located at the outer ends of the compressor shaft.

Seal oil equipment may be either configured as a console or may be designed as individual pieces of equipment.

Surface condensers—reduce gas or vapor to a liquid by heat removal.



Surface condenser—once enough heat has been eliminated liquefaction occurs.

Condensate pump—these are usually vertical type, and they remove the condensate from the hot well in the surface condenser.

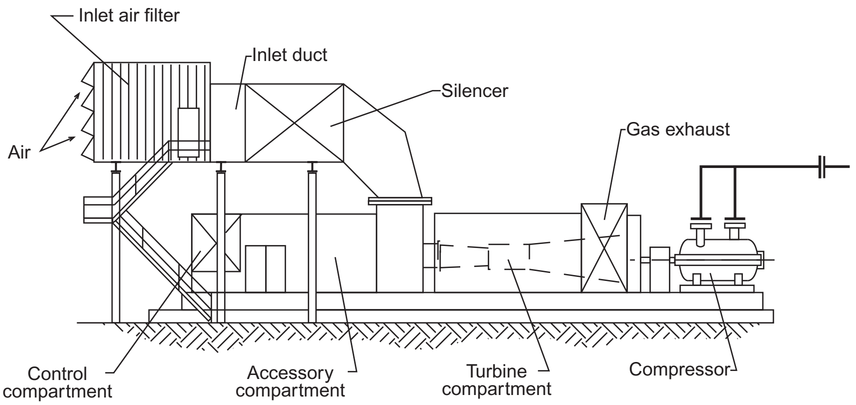
Condensate pumps—during liquefaction, condensate forms in the condenser and is collected in the hot well.

Air blowers—these are usually motor-driven centrifugal fans which deliver air to cool the internally housed electric motors.

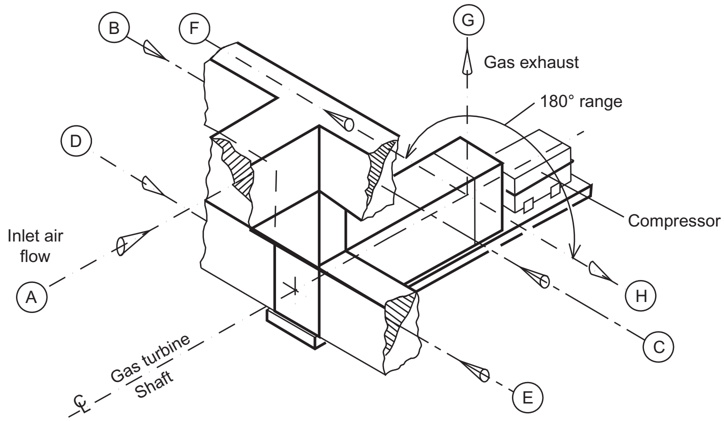
Air blowers—air is delivered to the motors through ducts and the exhaust is either sent back into the compressor house or to atmosphere.

Inlet air filters—gas turbines require large amounts of clean filtered air for operating.

Inlet air filters—because these filters can be very large it is important to position the gas turbine compressor in the correct location, by taking into account the possible variations in orientation of the inlet and outlet ducting.

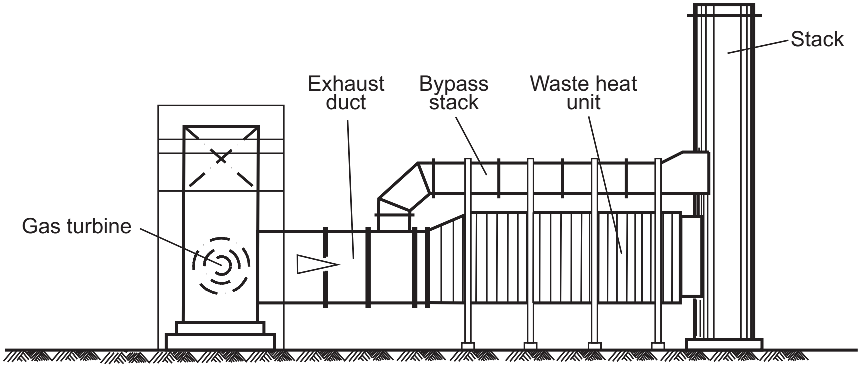


Inlet air filter



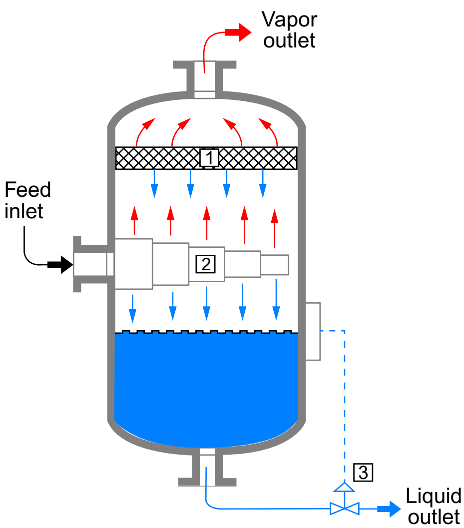
Inlet air filter

Waste heat systems—take hot exhaust gases from gas turbines and put these high-temperature gases (800–1200°F/426–650°C) to use in various ways. By convection, the waste heat can be used to heat oil or generate steam, which can then be used as a heating medium.



Waste heat system

COMPRESSOR SUCTION DRUM/KNOCKOUT POT



1 De-entrainment mesh pad
2 Inlet diffuser (distributor)
3 Liquid level control valve

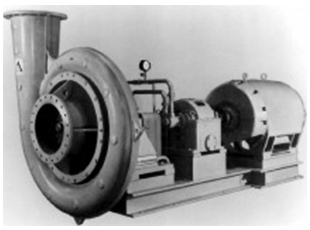
Compressors require dry gas that is free of particles; therefore, it is necessary to pass the inlet gas through a suction drum/knockout pot. The **Suction Drum/Knockout Pot** removes particles from the gas by passing it through a demister screen located below the outlet nozzle.

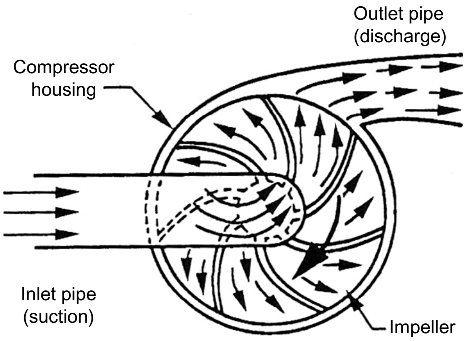
8.3 CENTRIFUGAL COMPRESSORS

Compressor drives can either be:

- Electric
- Steam turbine
- Gas turbine

A **centrifugal compressor** compresses air and expels it with a centrifugal force from a rotating wheel with radial vanes.

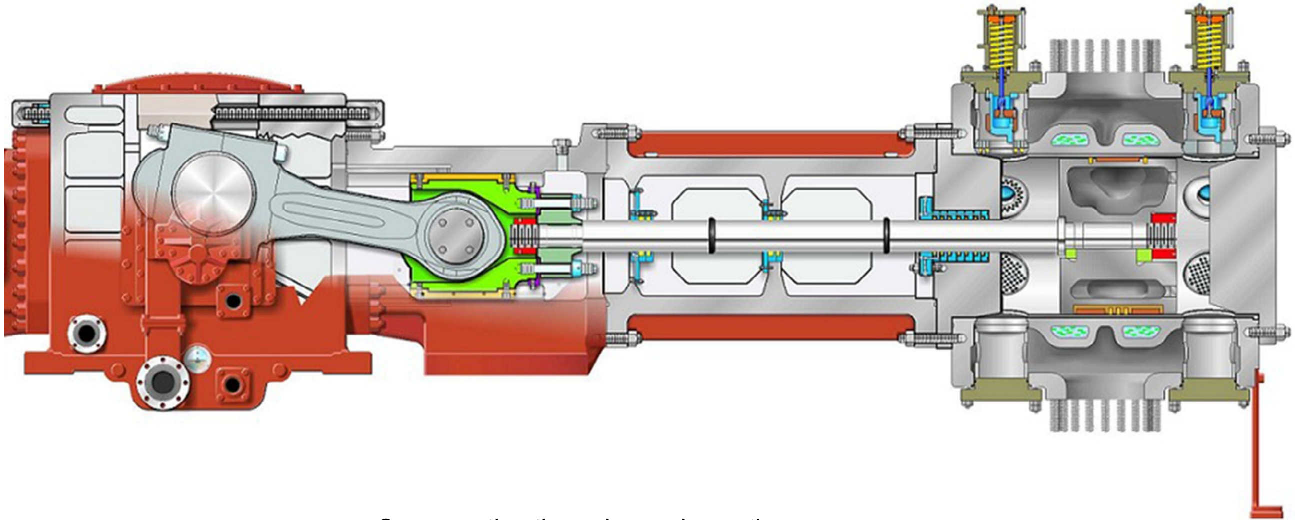




8.4 RECIPROCATING COMPRESSORS

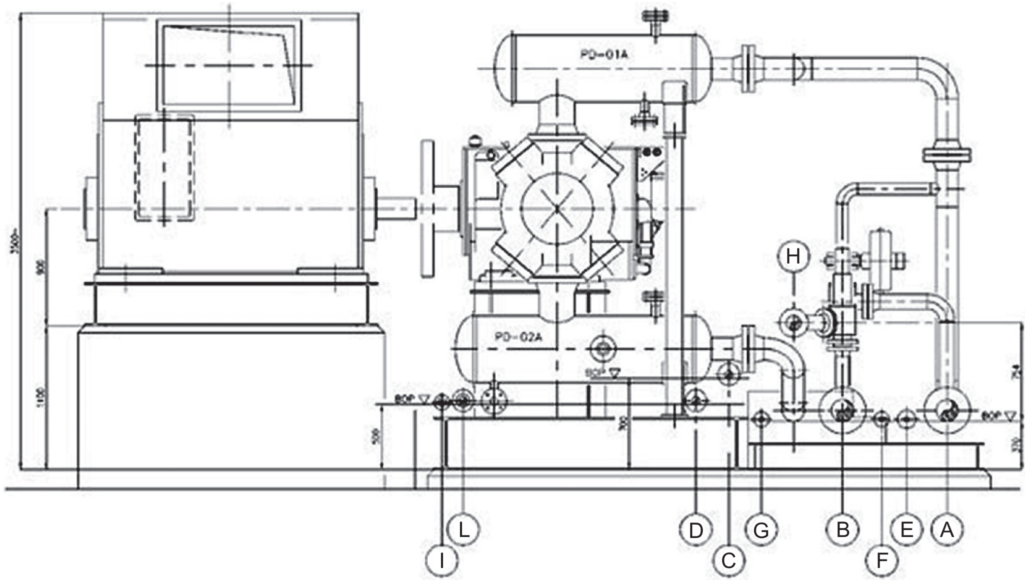
A **reciprocating compressor** is a positive-displacement compressor that uses pistons driven by a crankshaft to deliver gases at high pressure.

The intake gas enters the suction manifold, then flows into the compression cylinder where it gets compressed by a piston driven in a reciprocating motion via a crankshaft, and is then discharged.



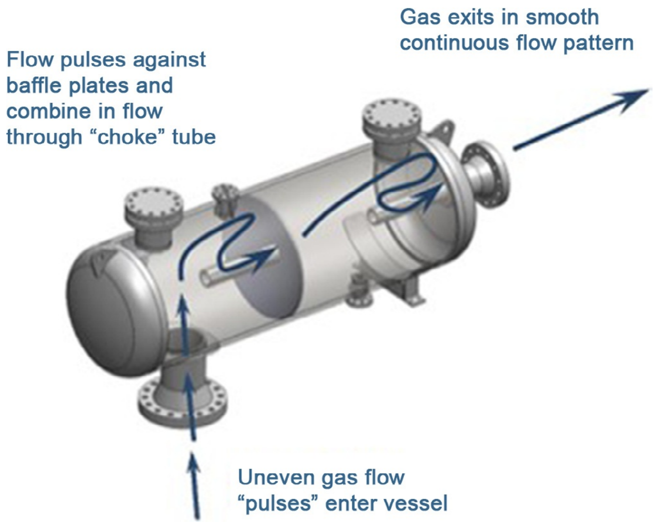
Cross section through a reciprocating compressor

Side view



Sectional drawing of a reciprocating compressor

Pulsation dampeners are used on **reciprocating compressors** to reduce the effects of vibration caused by the pulsing effect that the compressor produces during operation.



- **Pulsation dampeners** are sized by the compressor vendor.
- **Pulsation dampeners** are mounted on the high-pressure outlet side of the compressor. The higher pressure on this side of the compressor mainly at the bottom of the cylinder is subject to the greater pulsation and vibration.

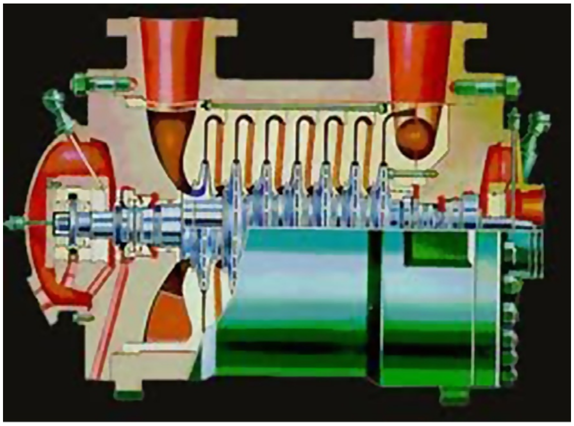
8.5 CASE DESIGN

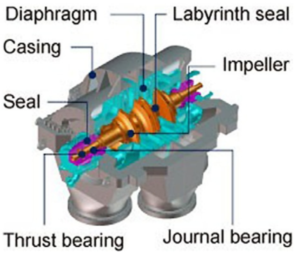
When making a compressor selection, the following design parameters have to be decided, therefore the following applications have to be understood, do we use?

- Horizontal split case
- Single stage
- Multistage
- Vertical split case
- Will the compressor be grade mounted?
- Do we use top- or side-mounted connections?
  - Elevated
  - Bottom connections

MAINTENANCE

The compressor casing (top half) is removed by lifting it away vertically from the bottom section. This is a preferred configuration for petro-chemical, oil and gas and low–medium pressure and high-volume applications.





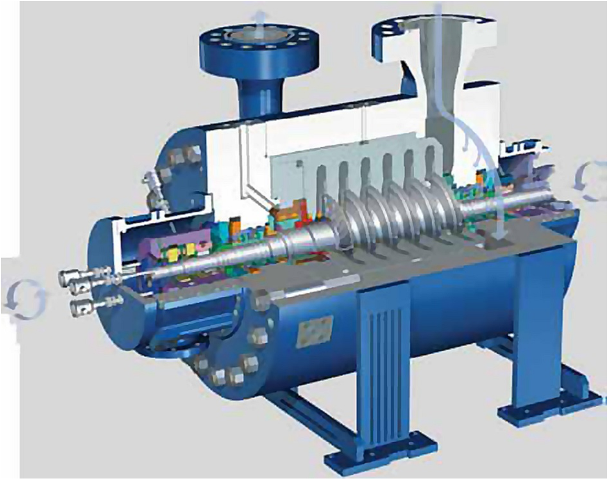
VERTICALLY SPLIT CASING COMPRESSORS

These are used for light gases and high pressures, and they are designed in accordance with API 617.

These are single shaft where compressor internals are assembled in a bundle.

This enables easy removal axially from the casing shell without the need to remove process gas piping.

An advantage when using top nozzles is that when used in place of horizontal split casings will benefit from their gas tightness in low molecular weight services.



8.6 TURBINE DETAILS

STEAM TURBINE

Back pressure:

- ➢ Uses high-pressure steam to drive the turbine (does not require a surface condenser)

CONDENSING

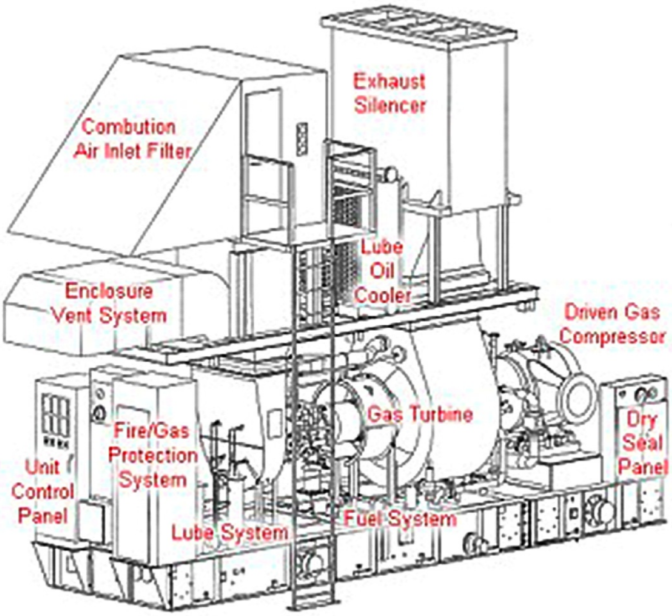
- ➢ Uses low-pressure steam (very efficient and therefore more common, needs surface condenser)
- ➢ Have fewer moving parts (less maintenance)
- ➢ Have low vibration levels
- ➢ Has a wide turbine speed range (1–100,000 HP/74,600 kW)

GAS TURBINE

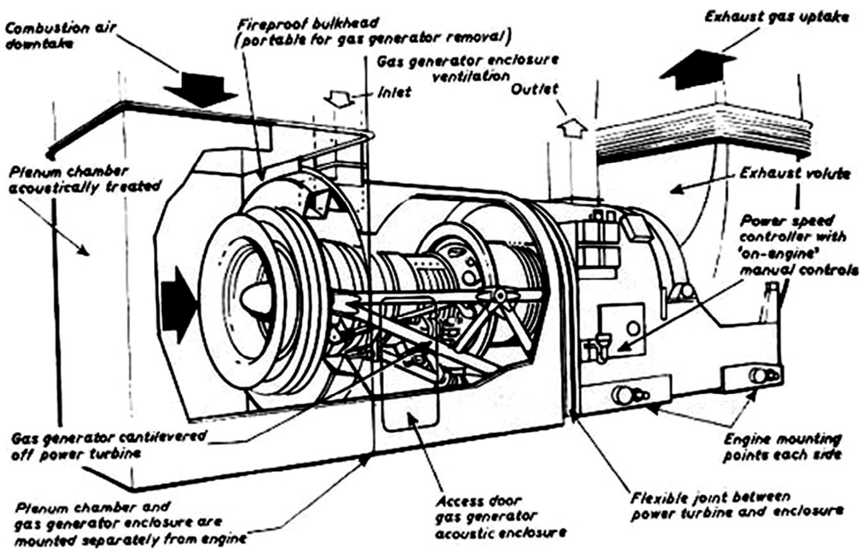
Selection of a gas turbine drive is based on:

- ➢ Economics
- ➢ Availability of gas in remote areas, desserts and offshore, makes it a viable source of power in these areas.
- ➢ Used in gas transmission, gas lift, liquid pumping, gas reinjection, and process compressors.

In a gas turbine air flows through a compressor that brings it to high pressure, the air is then discharged into a reverse flow annular combustor in which fuel is injected through nozzles, and a transition duct directs the hot gas generated into a gas generator turbine which then drives the compressor.

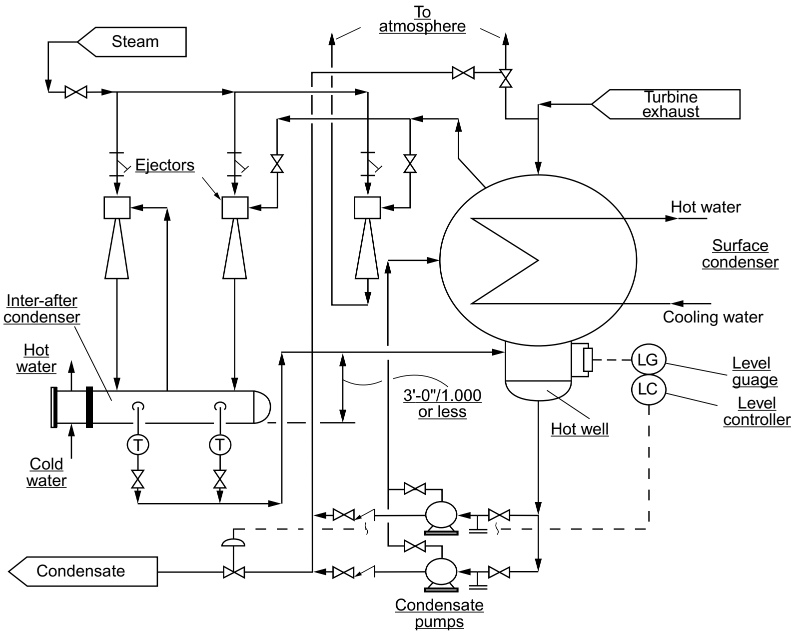


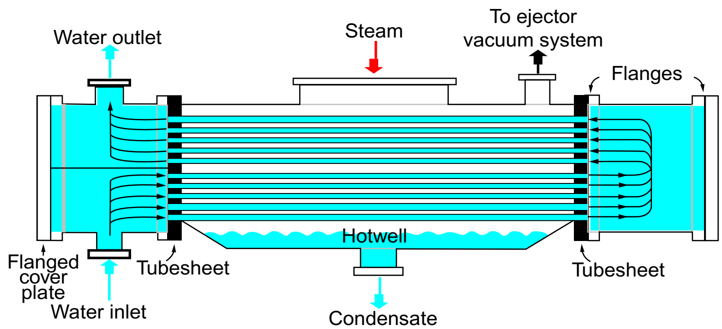
Gas turbine compressor



8.7 SURFACE CONDENSER

Surface condensers reduce gas or vapor to a liquid by heat removal. In a surface condenser once enough heat has been eliminated liquefaction occurs.





Surface condenser

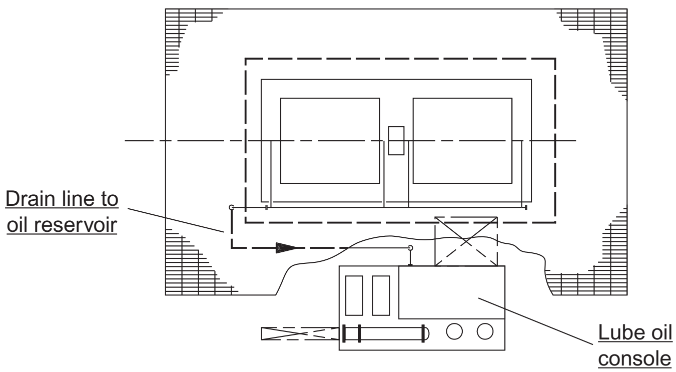
8.8 LUBE OIL SYSTEMS

Lube oil consoles are designed to provide pressurized cool lubricating oil to the bearings of the compressor and its driver.

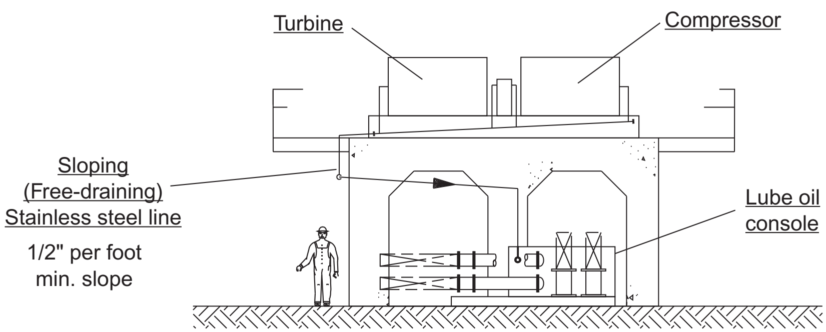
The lube oil console can either be standalone units, or mounted on structural steel bases mounted directly to the compressor frame. This makes for easy and safe transport to the facility.

API 614 Standard (ISO 10438) special purpose oil systems, and API 618 Standard (ISO 13707), general purpose, and non-API lubricating oil consoles, are the standards used for these systems.

Lube oil skid



Plan



Elevation

8.9 SEAL OIL SYSTEMS

Seal oil systems are used to supply oil to the hydraulic seals of the compressor. These are located at ends of the drive shaft.

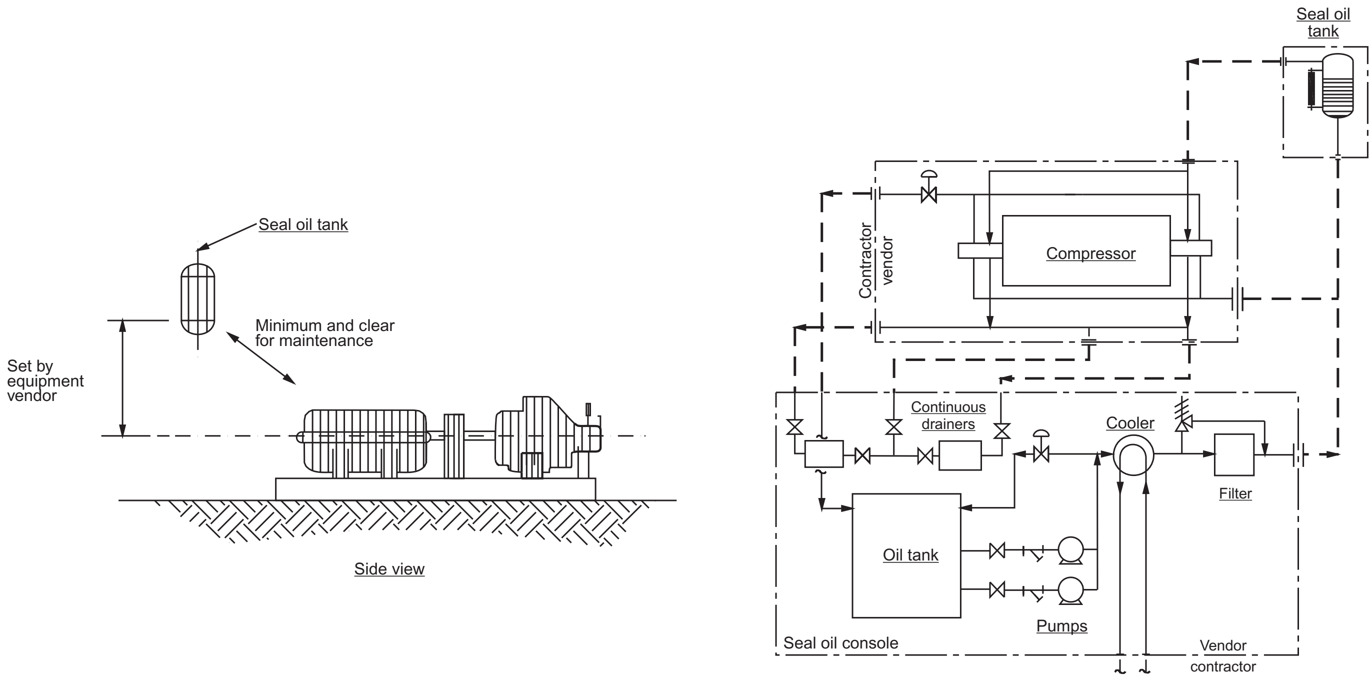
The **seal oil** is delivered to the seal at a constant temperature and pressure. The oil that escapes from the low-pressure side of the seal, returns to the reservoir and is recirculated.

The oil that escapes from the high-pressure side passes through a sour oil trap to the seal oil gassing tank.

There are two types of **seal oil** systems:

- Gravity
- Pressurized

Seal oil console



Seal oil systems

8.10 MAINTENANCE

Compressors can be located in open plant areas or structures.

Whether or not the compressor is located in the open plant or in a structure, the compressor can be enclosed in one of the following ways:

- Roof
- Curtain Wall
- Totally Enclosed

The factors determining location of compressor are:

- Client Preference
- Climate conditions
- Elevated
- Grade Mounted

Compressor location has an impact on maintenance.

Safety and operability must also be taken into consideration when considering maintenance.

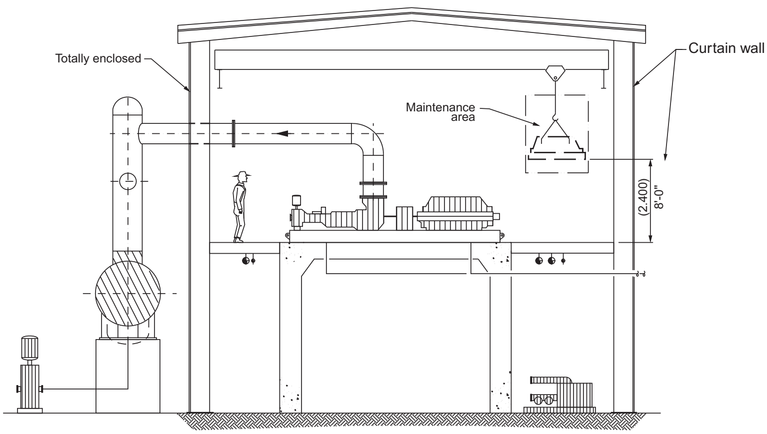
Engineer must determine whether the compressor should be grade mounted or elevated.

If grade mounted then the compressor sits on a concrete pad with the lube oil console sitting close by the suction and discharge piping in this scenario will enter the compressor from the top, so this means the piping will have to be removed before maintenance on horizontal split casings machines can be achieved.

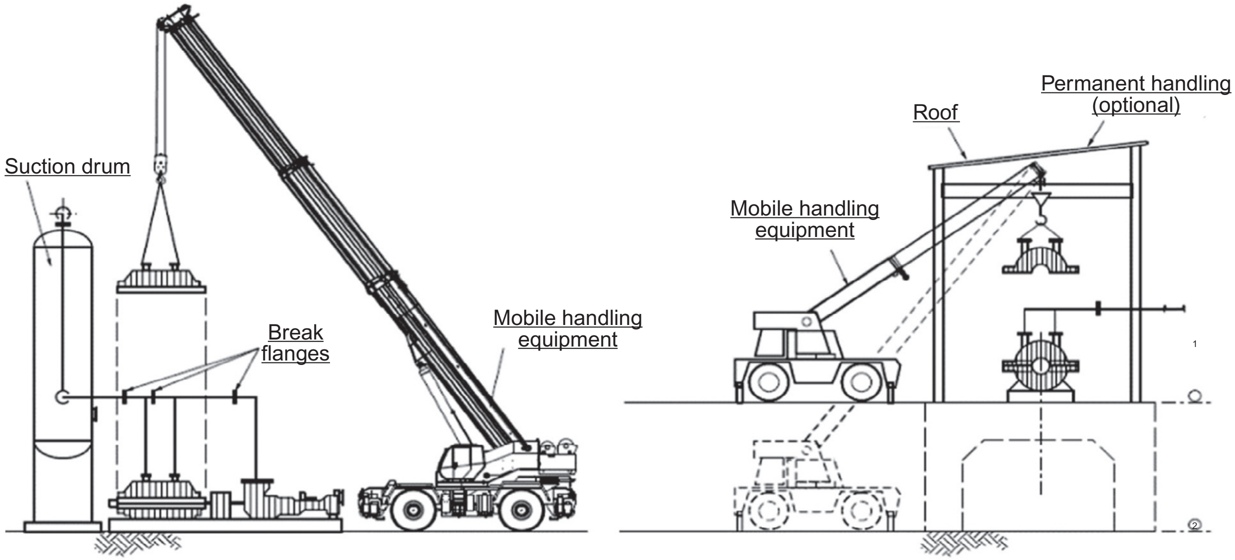
If condensing turbines are used then the exhaust piping will have to be removed before access to the compressor casings.

If an elevated compressor with a condensing turbine is used, then the suction and discharge piping along with exhaust outlets can be left in place for maintenance.

Elevated compressor structures will have a greater initial capital expenditure than grade mounted, but over the lifetime of the plant, the downtime will be shorter due to easier maintenance.



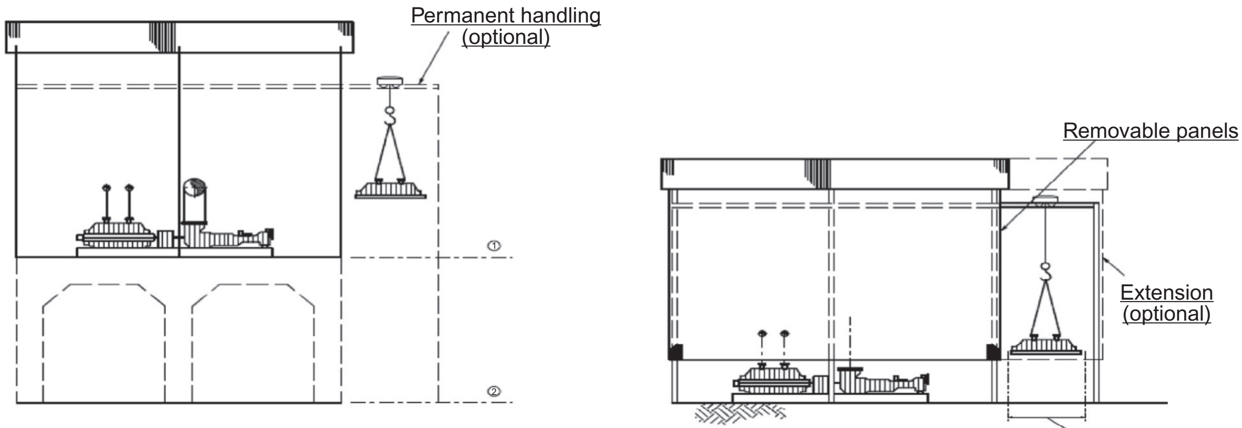
Maintenance



Grade mounted (open)

Elevated (enclosed)

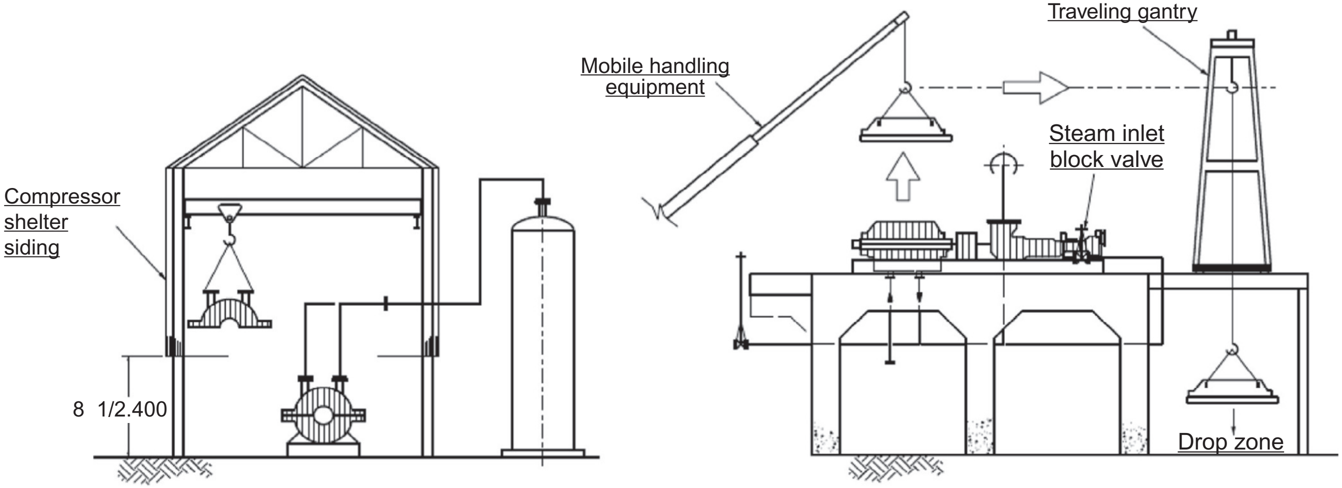
Maintenance



Elevated (open)

Maintenance

Grade (removable panels)



Grade (partial siding)

Elevated (open)

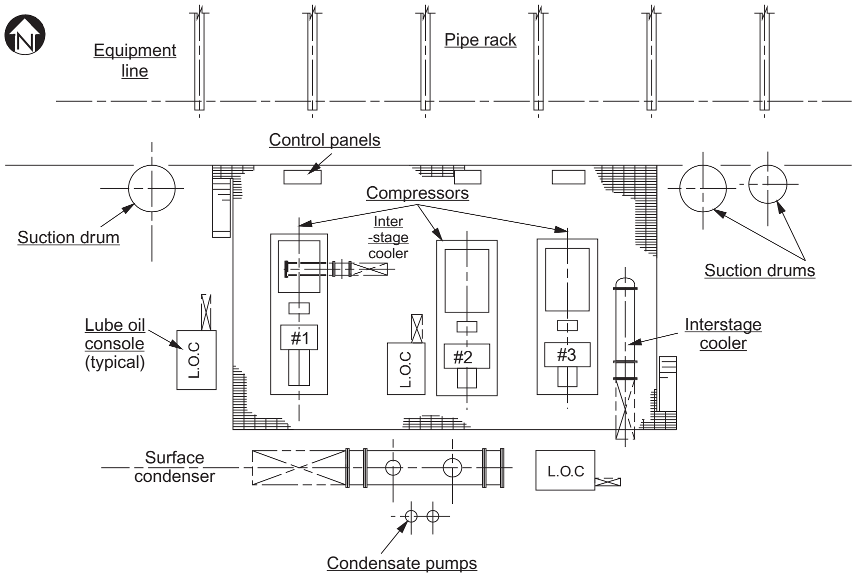
Maintenance

8.11 COMPRESSOR LAYOUT

LAYOUT NO. 1

The following layout shows:

- 3 centrifugal compressors
- 3 lube oil consoles
- 3 condensing steam turbines
- 2 intercoolers
- 3 suction drums
- Surface condenser
- 2 vertical condensate pumps



The 3 steam turbines operating at low steam pressure need to minimize length of exhaust line to the surface condenser.

The Location of the lube oil consoles allows return lines to drain without obstruction to the oil reservoir.

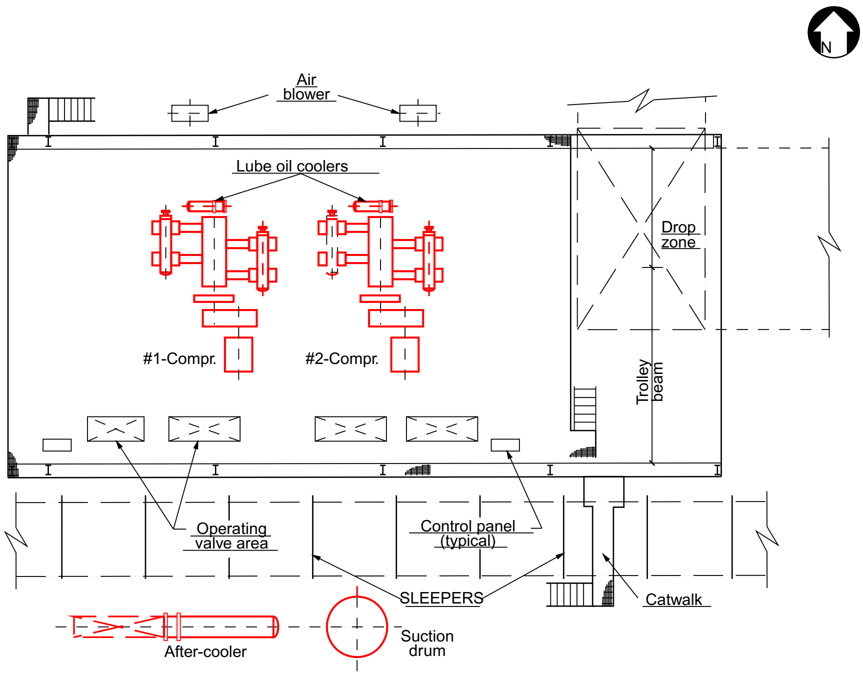
The intercooler for Comp 3 is located below machine (vendor supplied) so good access is required for tube removal.

LAYOUT NO. 2

The following plan indicates:

- 3 electric motor-driven reciprocating compressors of two different sizes
- Air blowers

- Suction drums
- Intercoolers
- Control panels
- Lube oil console



Compressor layout plan

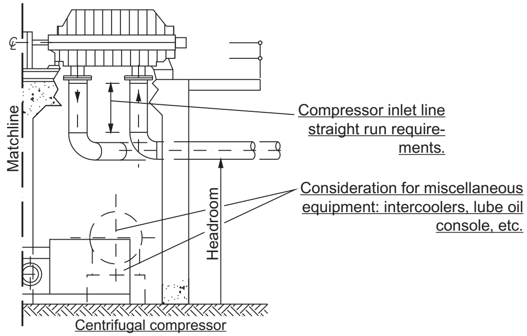
When approaching the layout make sure to line up the electric motors. In this particular arrangement, Compressor 1 has a lube oil console located to the north below the platform, so removable platforms are required for maintenance.

Compressors 2 and 3 have integral lube oil consoles mounted directly to comp.

CENTRIFUGAL COMPRESSOR

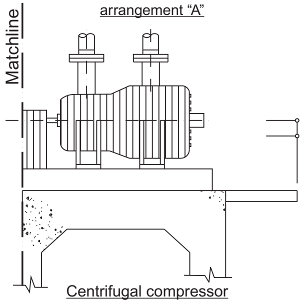
What sets a compressor elevation? Two items have an influence on this, and they are:

- Type of driver
- Straight run requirements of the compressor inlet piping

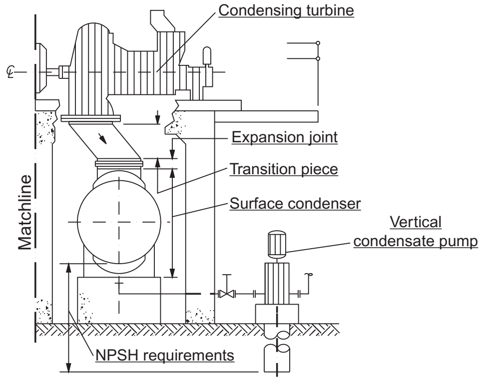


Centrifugal compressor
horizontal split case
bottom connections
or
Vertical split case
bottom connections
arrangement "A"

Compressor arrangement	Drive arrangement	Elevation governed by	Remarks
A	C	C	
A	D	A	
A	Electric motor	A	Motor not shown
B	C	C	
B	D	NA	Usually grade-mounted arrangement
B	Electric motor	NA	Usually grade-mounted arrangement

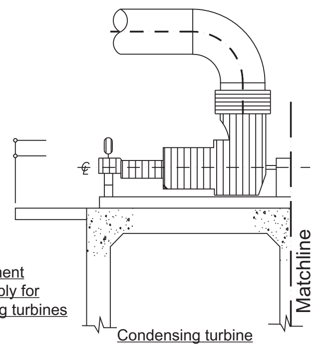


Centrifugal compressor
vertical split case
top connections
or
Horizontal split case
top connections
arrangement "B"

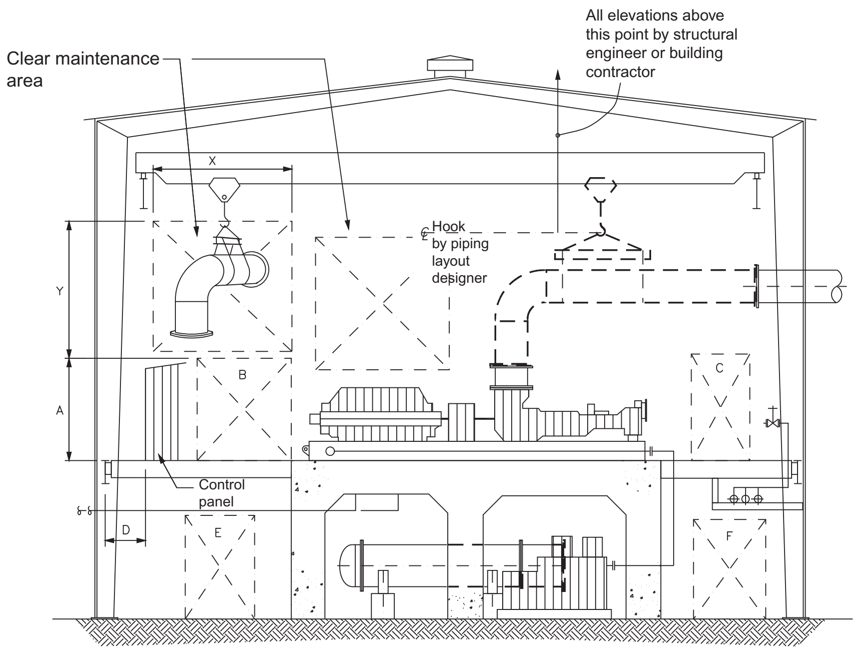


Condensing turbine
bottom exhaust
arrangement "C"

Note:
This arrangement
would also apply for
noncondensing turbines



Condensing turbine
top exhaust
arrangement "D"

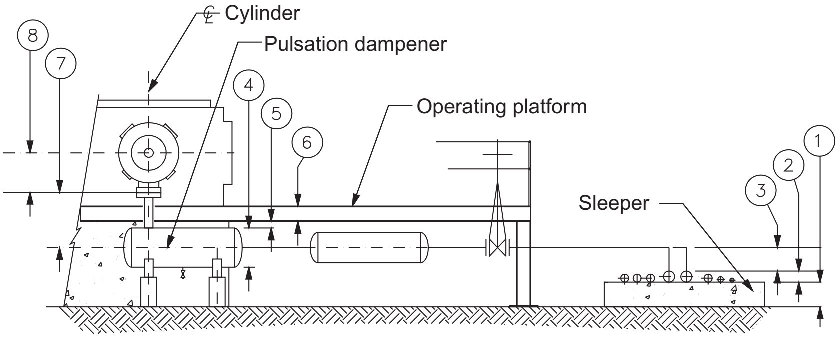


Compressor layout

RECIPROCATING COMPRESSORS

The elevation of a compressor set by the following:

- Sleeper—12–18″/300–400 mm above grade
- Header size (per P&ID)
- Min. distance required to enter sleeper rack
- Pulsation dampener (by comp. vendor)
- Min. clearance required between dampener and floor steel
- Max depth floor steel (by structural engineer)
- Dimension from centerline of dampener to face of nozzle (by vendor)
- Bottom of compressor baseplate to centerline of shaft (by vendor)



Compressor layout

COMPRESSOR LAYOUT

Inter and after coolers are used to reduce operating temperature in a compressor circuit.

Using inter and after coolers allows for the use of smaller machines with fewer cylinders.

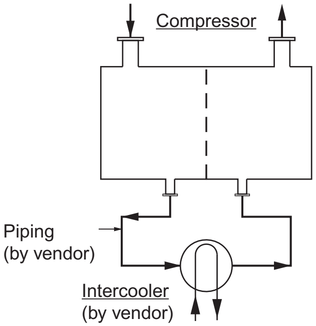
Coolers vary in size and can be of the following types:

- Shell and Tube
- Air coolers
- U-Tube

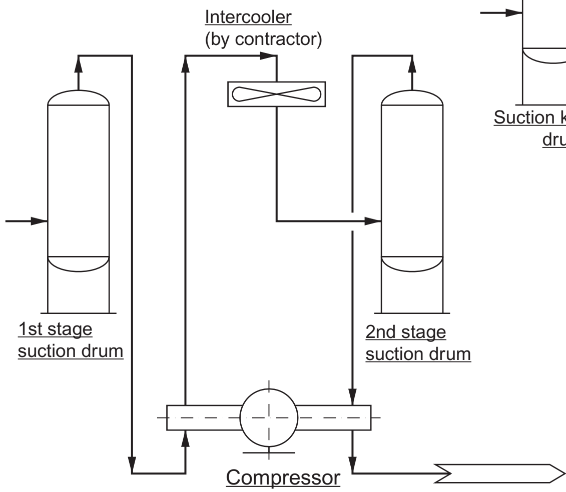
Whichever type of cooler is used they need to be located as close to the compressor as practical.

They can be mounted on and directly over the compressor (by vendor).

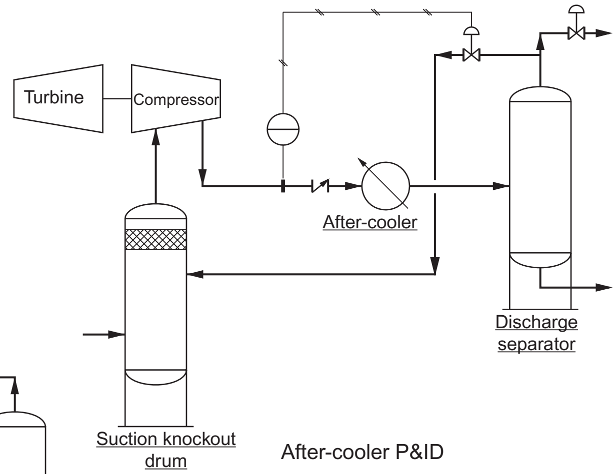
Usually though they are located by the engineering contractor close to the machine or stage suction drum.



Centrifugal compressor



Reciprocating compressor



After-cooler P&ID

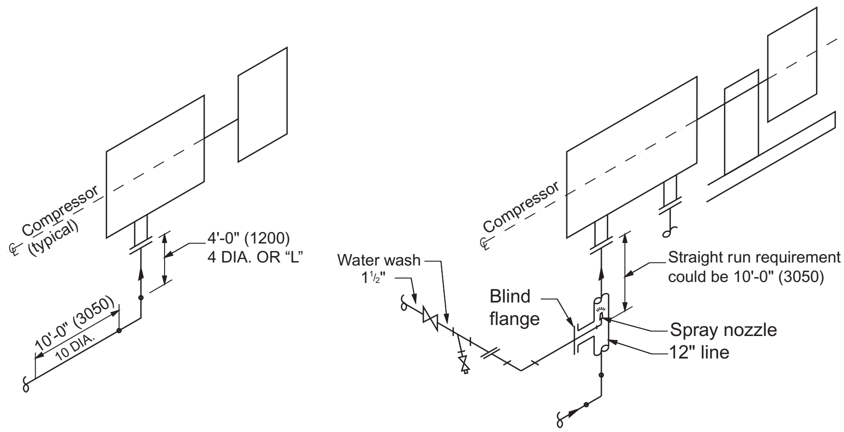
8.12 COMPRESSOR PIPING

The compressor inlet line is extremely important and must meet ASME power code test requirements which state:

- Minimum of three diameters required of straight run piping between the elbow and inlet nozzle.
- Preferred piping arrangement where the horizontal run is parallel to the compressor shaft

The piping engineer shall consult with the equipment engineer to establish a design that will optimize the operation.

Maintenance, safety, and economic requirements are mandatory and other considerations may include is water was injection required in the gas stream.



Compressor layout

COMPRESSOR PIPING

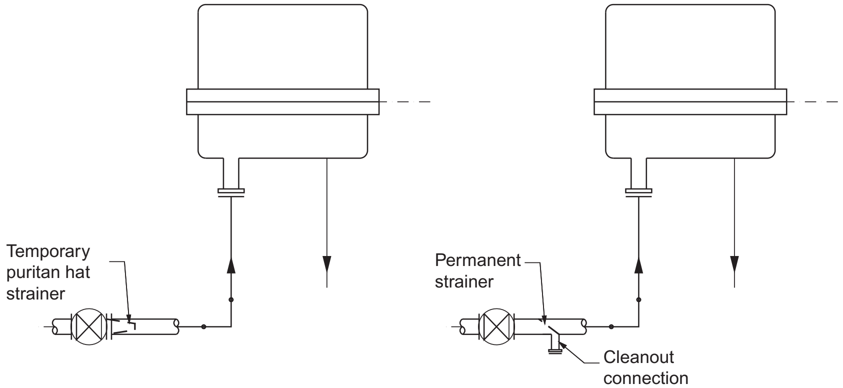
Inlet line (suction) strainers are used in the compressor suction line to enable the compressor to be free of any particles that could cause damage to the machine internals.

To alleviate this strainer is installed in the inlet line between the block valve, and the compressor inlet nozzle.

After the compressor has been run for some time, the strainers are removed. This requires a shutdown of the compressor.

Strainers can be of two types:

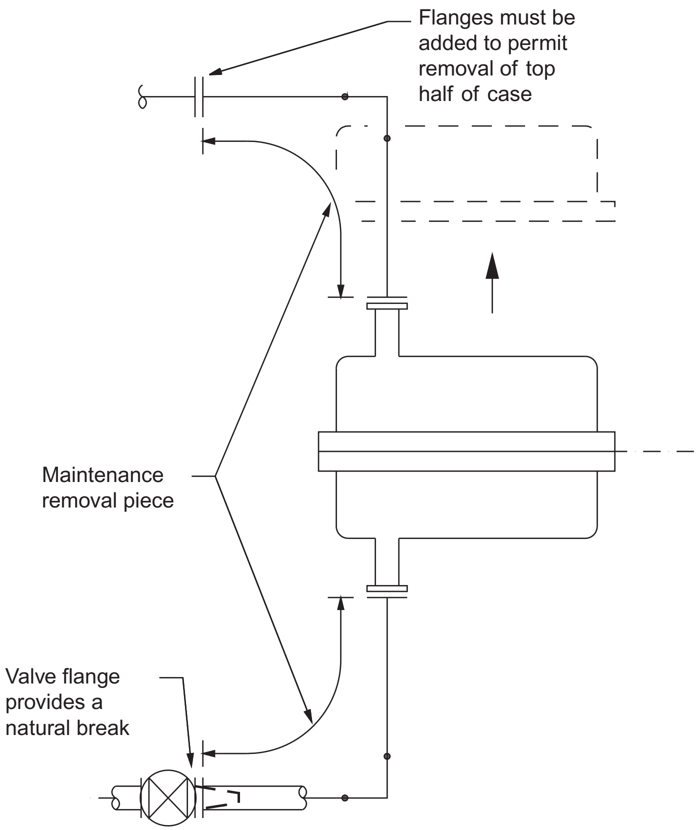
- **Temporary—**where the strainer is removed for cleaning.
- **Permanent—**where the strainer remains in line permanently. This type of strainer must have a clean out connection to remove any foreign matter trapped in the filter.



Compressor layout

BREAK OUT FLANGES

Any line to and from the compressor that requires removal for maintenance must be provided with **"Break out Flanges."** On the inlet line the strainer will need a set of flanges in addition to the flange at the compressor inlet nozzle, to enable removal of the strainer.



Compressor layout

TURBINE INLET PIPING

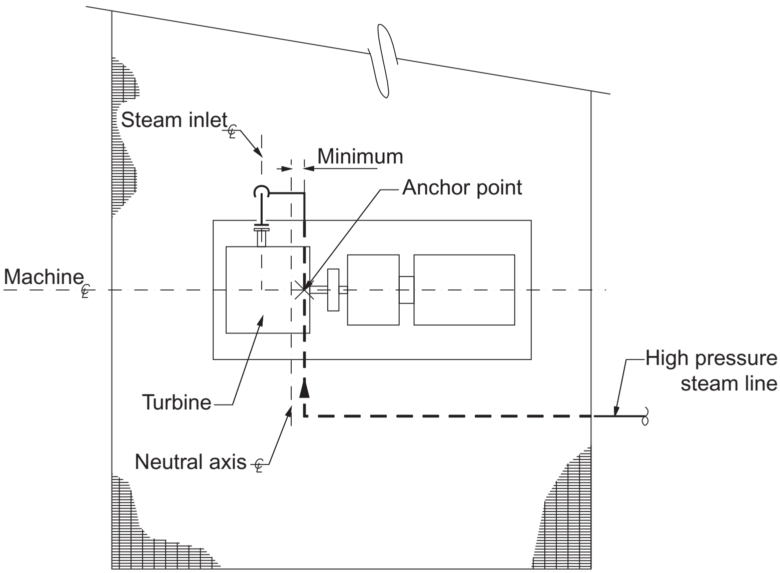
The steam inlet piping to the turbine is high pressure and high temperature.

Therefore, flexibility of the steam inlet line is of prime importance.

The engineer should review the compressor outline drawing to determine the location of the neutral axis.

This is the point where the turbine is anchored to the compressor frame.

By locating the line anchor as close to this point as possible, the engineer will have succeeded in providing a layout with the minimum amount of leg on the inlet, and this then will hopefully satisfy the flexibility and stress requirements of the system (this will be further checked by the stress engineer).



Compressor layout

STRAIGHTENING VANES

When the inlet line straight run requirements of 4 diameters as required by ASME standards cannot be met, straightening vanes may be installed to smooth out the flow, which in turn improves the compressor performance.

If straightening vanes are used, then they must be in accordance with ASME or American Gas Association standards.

RECIPROCATING COMPRESSOR PIPING

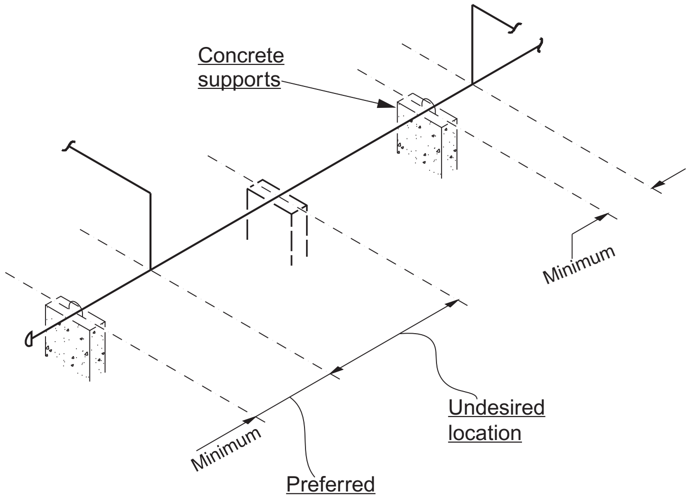
If the piping arrangement on a reciprocating compressor system is not correctly designed, it can lead to pulsation problems, which in turn will reduce the machine capacity and require an increase in HP/kW requirements.

Piping arrangements should see lines run as low to grade as possible for ease of support.

When the engineer has designed the piping arrangement for the compressor, the proposed piping configuration must be submitted to the compressor vendor or independent consultant to perform an analog study. This study will identify any potentially damaging acoustic or pulsation problems during the design phase, thus eliminating high repairs or redesign costs at a later date.

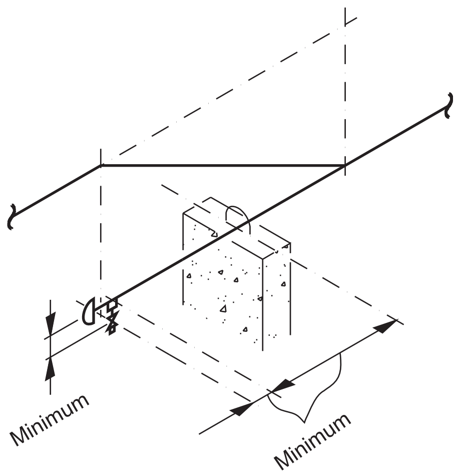
LINE BRANCHES

Branches should be located as close as possible to a line support.

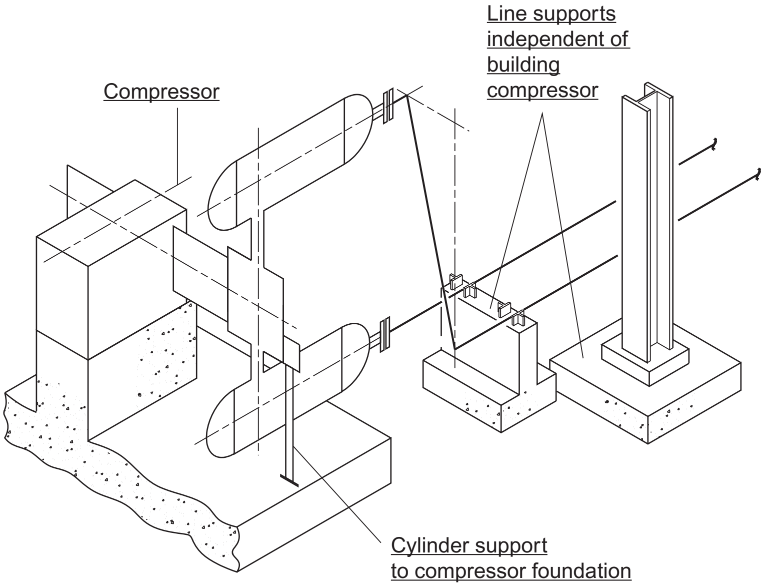


Drain Piping—provided on both suction and discharge piping, to prevent liquid going into the cylinders.

Care must be taken when connecting drains in hazardous and high-pressure systems.



The following arrangement showing anchor (thrust Blocks) line support foundations, located independently of compressor foundation.


Line supports
independent of
building
compressor
Compressor
Cylinder support
to compressor foundation

CHAPTER

Furnaces

9

9.1 BASIC OPERATION

Furnaces are also referred to as **heaters.** They are one of the main pieces of process equipment in a facility.

A furnace is used to raise the temperature of a gas or hydrocarbon liquid to meet specific processing requirements. A furnace can also be used in a pyrolysis application as a "**Reformer Furnace"** where it causes a chemical or physical change to the medium.

The most common types of Furnace or Heater are the **"Circular"** or **"Box Type."** Other types of furnace are "**Pyrolysis"** and **"Reformer"**

Heaters

9.2 PRIMARY PROCESSES

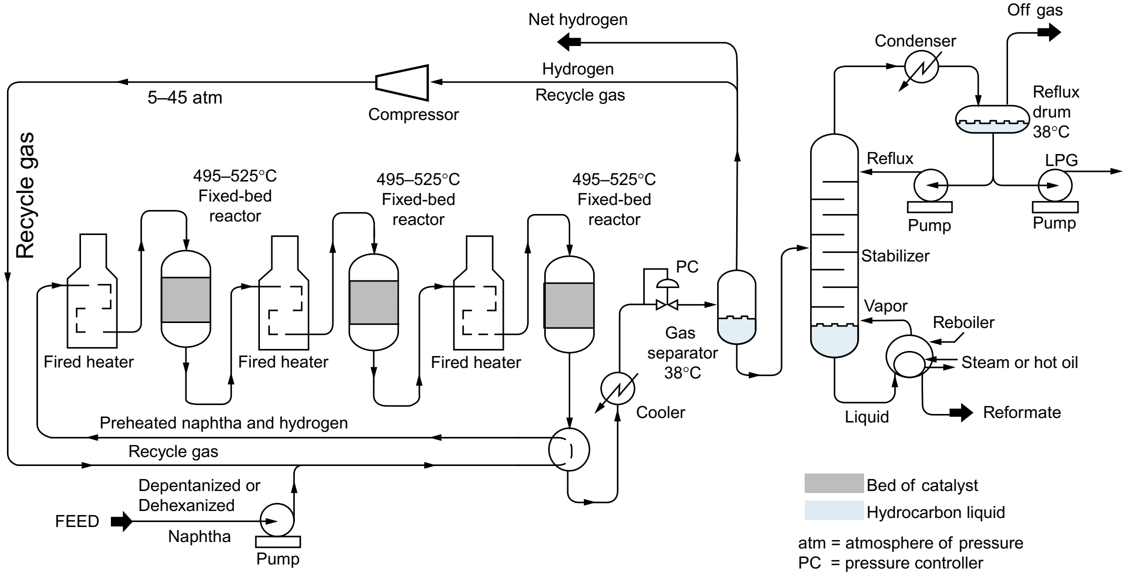
Catalytic reforming is a chemical process used to convert petroleum refinery, naphtha's, typically having low octane ratings, into high-octane liquid products called **reformates** are components of high-octane gasoline (also known as high-octane petrol).

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00009-6

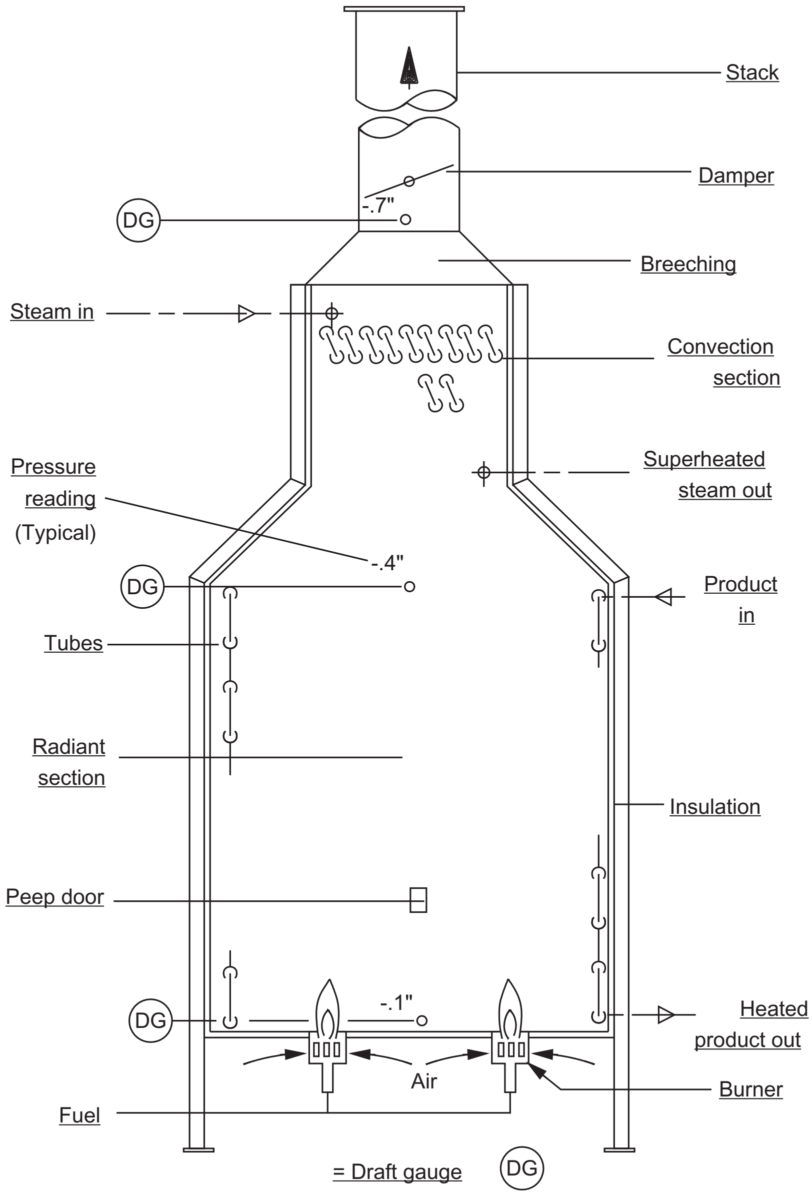
Basically, the process rearranges or restructures the hydrocarbon molecules in the naphtha feedstock's as well as breaking some of the molecules into smaller molecules. The overall effect is that the product reformate contains hydrocarbons with more complex molecular shapes having higher octane values than the hydrocarbons in the naphtha feedstock. In so doing, the process separates hydrogen atoms from the hydrocarbon molecules and produces very significant amounts of byproduct hydrogen gas for use in a number of the other processes involved in a modern petroleum refinery. Other byproducts are small amounts of methane, ethane, propane, and butanes.

STEAM REFORMING

This process is quite different from and not to be confused with the catalytic steam reforming process used industrially to produce various products such as hydrogen, ammonia, and methanol from natural gas, naphtha, or other petroleum-derived feedstock. Nor is this process to be confused with various other catalytic-reforming processes that use methanol or biomass-derived feedstocks to produce hydrogen for fuel cells or other uses.



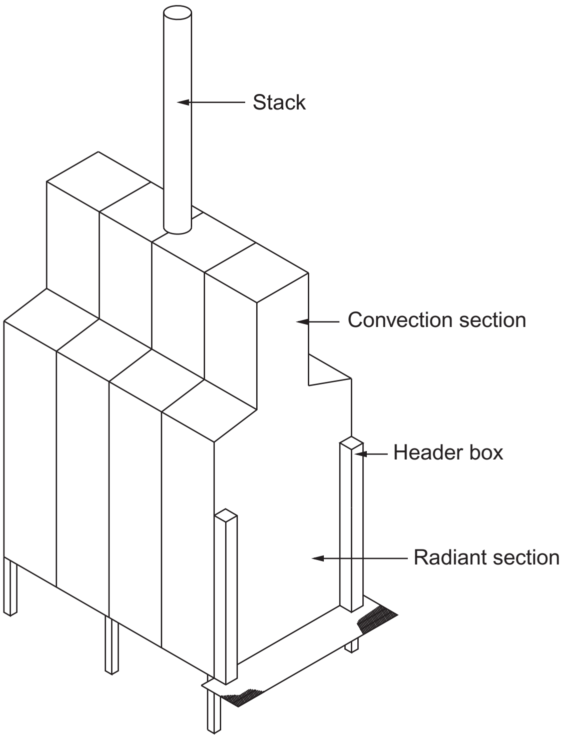
PFD (process flow diagram) — Steam reforming



Heater—Basic operation

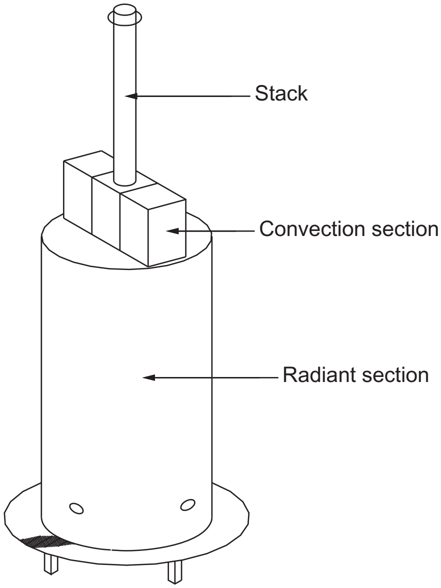
9.3 TYPES OF FURNACES

- **Box furnace**—houses rows of horizontal or vertical tubes in the radiant section, here gas can pass in an upward or downward flow. The convection section is located downstream from the radiant section where the flue gas passes in an upward or downward flow. The primary source of heating is burners in the radiant section.



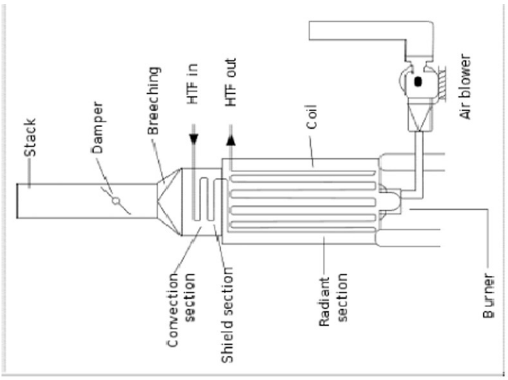
Box furnace

- **Circular furnace**—houses tubes mounted vertically or helically in the radiant section. This type of furnace is generally used for small duties or as a startup heater or reboiler. The inlet and outlet connections are located at the top or bottom of the radiant section depending on the product being heated, and are located at one end of the convection section.

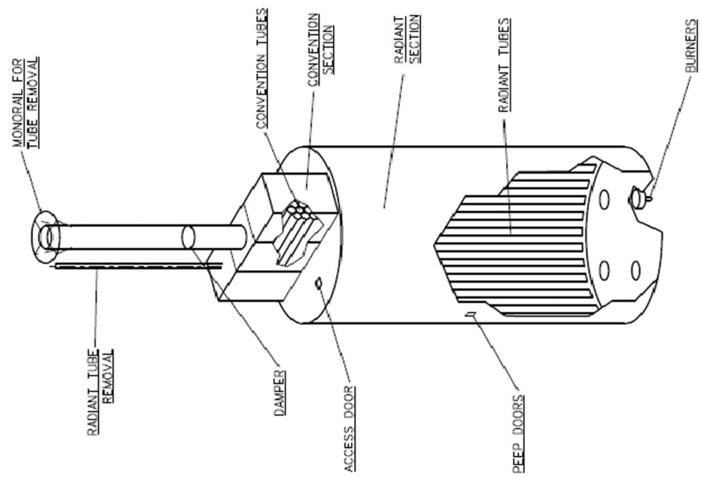


Circular furnace

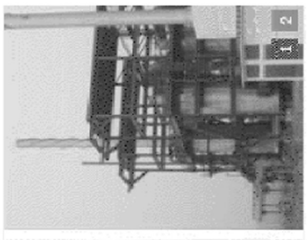
- **Pyrolysis furnace**—the tubes on this type of furnace are housed in the center of the radiant section. This is due to the short residence time, high heat transfer rate and need for even temperature distribution in the tubes.

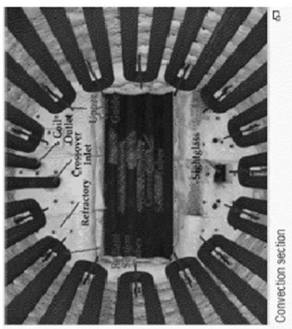


Middle of radiant section

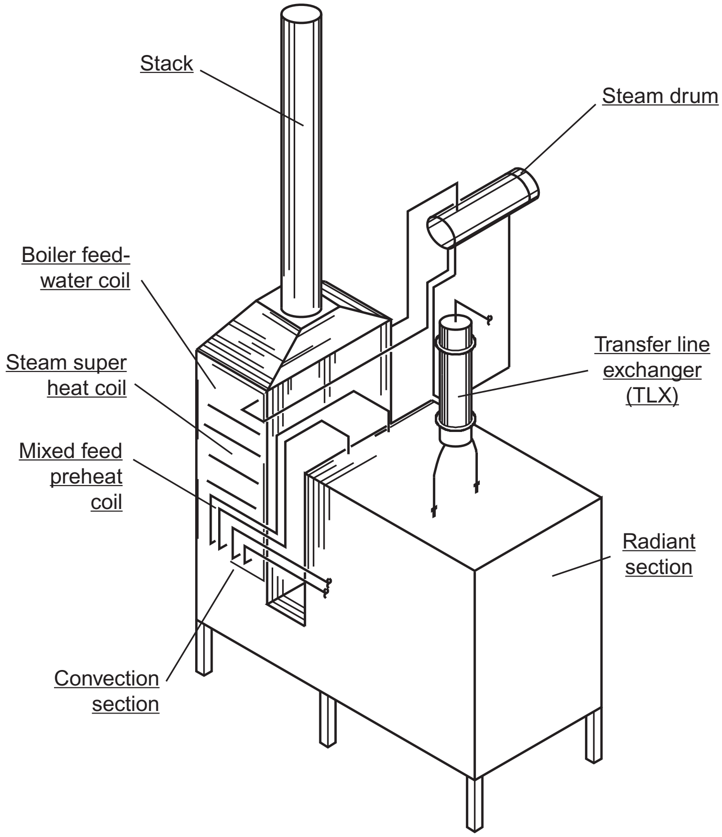


RADIANT TUBE REMOVAL IN A CIRCULAR FURNACE



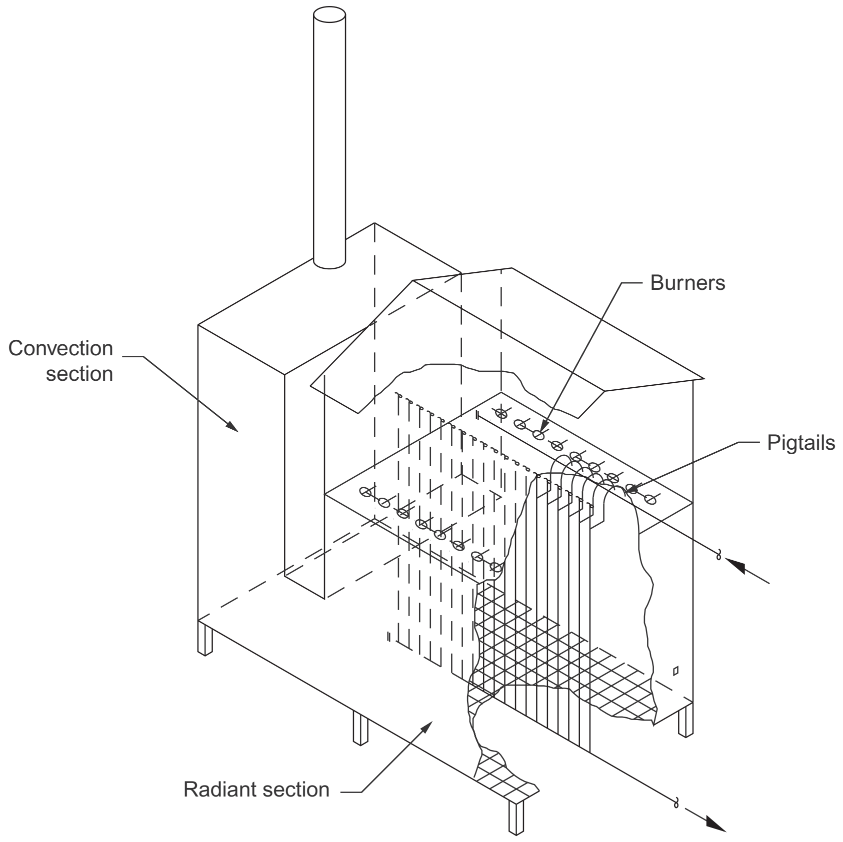


Convection section



REFORMER

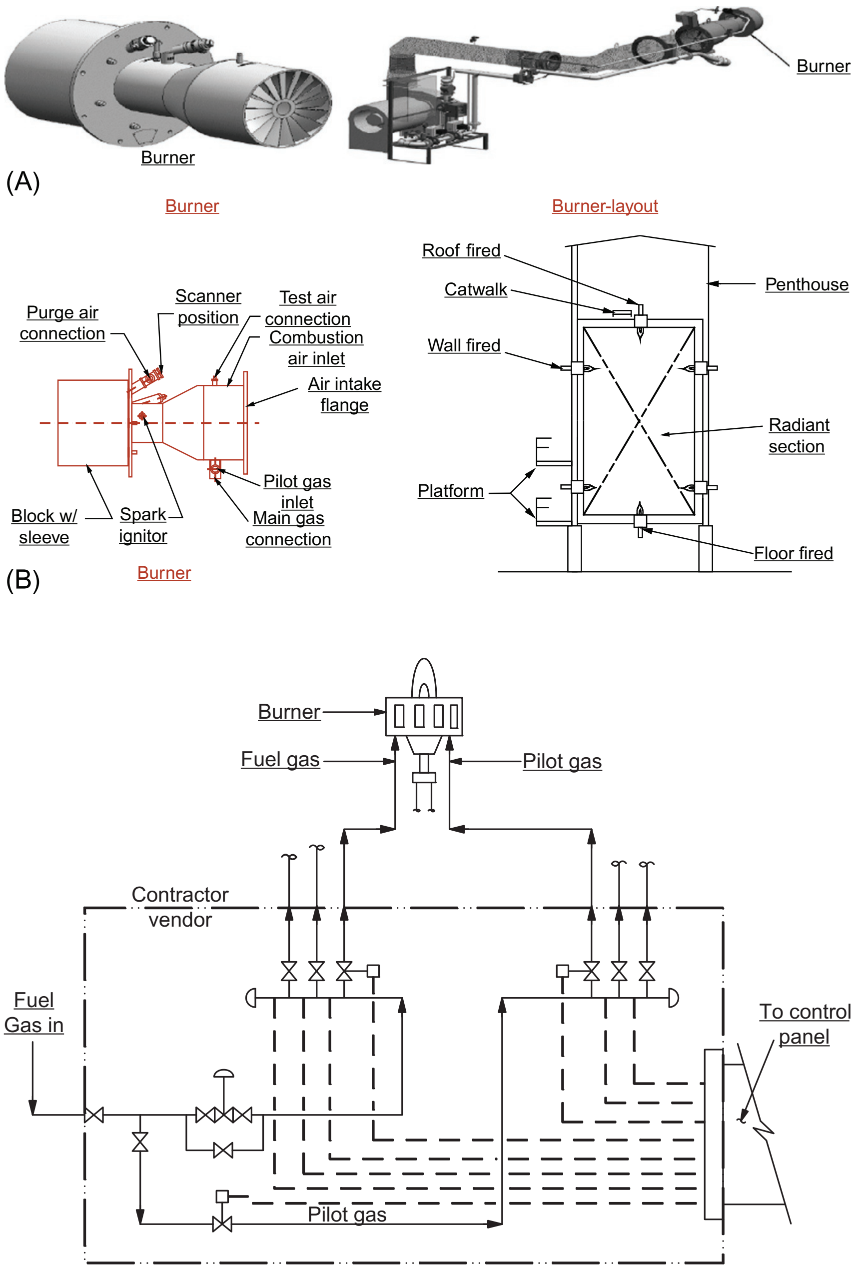
In a **reformer** preheated process fluid flows through catalyst-filled tubes, which are located in the center of the radiant section. A **reformer** can have single or multiple compartments. The burners may be mounted in the roof, wall, or floor. Heat recovery systems can be used by the use of waste heat boilers or convection section steam generation coils.



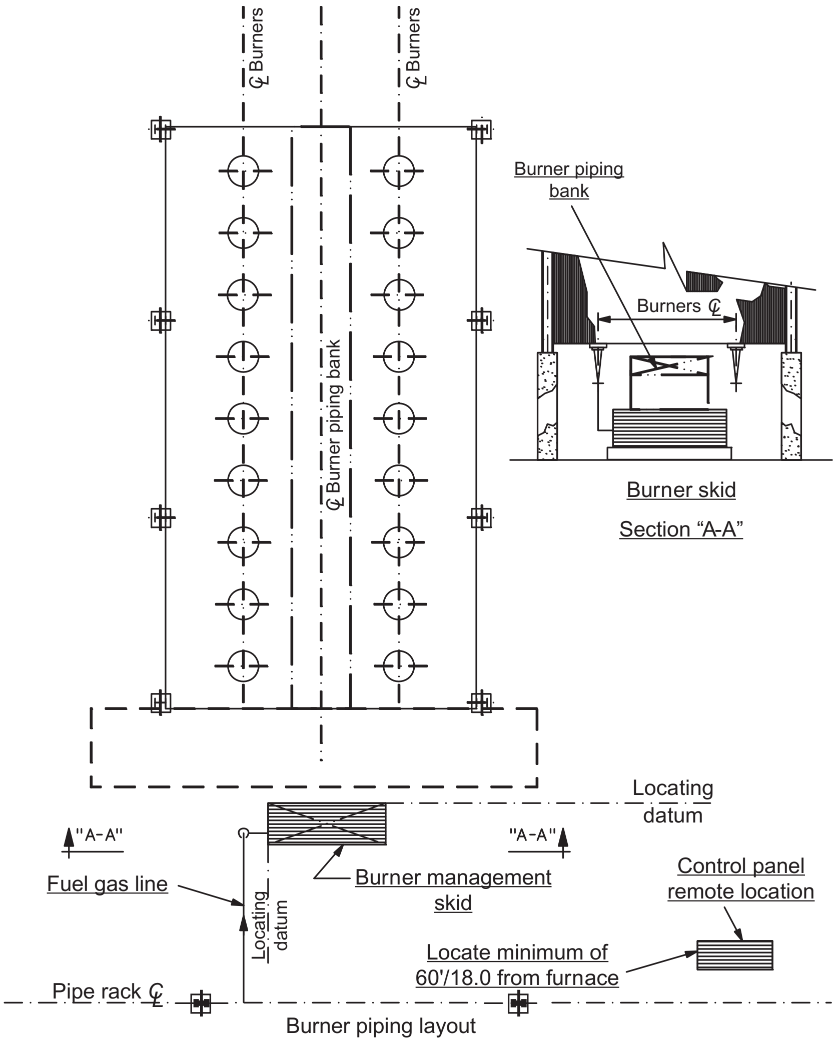
9.4 BURNERS

The determining factor in the choice of burner is:

- Furnace structure.
- Heat release requirements.
- How are the burners to be fired by gas or by liquid?
- What will be the burner configuration? Burners come in a variety of configurations.

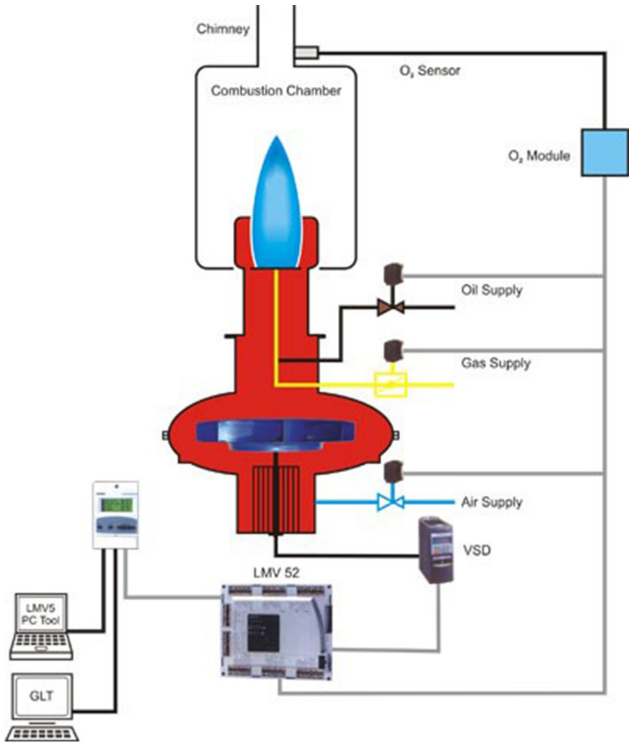


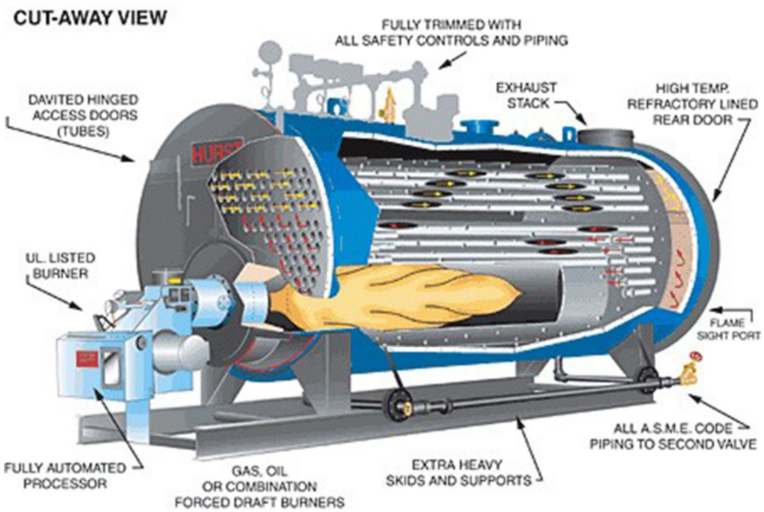
Burner schematic

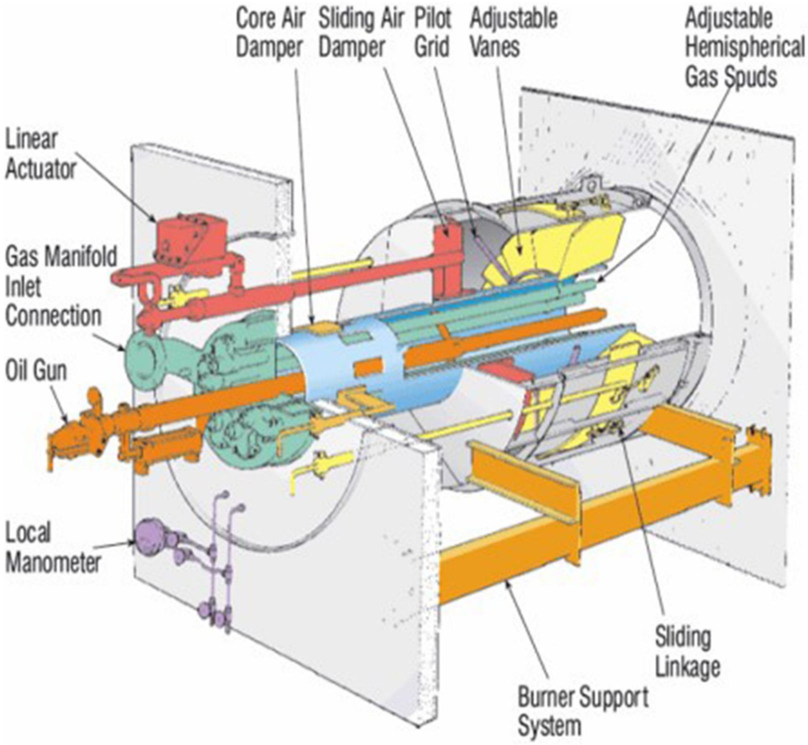


℄ Burners
℄ Burners
℄ Burner piping bank
Burner piping bank
Burners ℄
Burner skid
Section "A-A"
Locating datum
"A-A"
"A-A"
Fuel gas line
Burner management skid
Locating datum
Control panel remote location
Locate minimum of 60'/18.0 from furnace
Pipe rack ℄
Burner piping layout

BURNERS


Chimney
O_2 Sensor
Combustion Chamber
O_2 Module
Oil Supply
Gas Supply
Air Supply
VSD
LMV 52
LMV5 PC Tool
GLT


CUT-AWAY VIEW
FULLY TRIMMED WITH ALL SAFETY CONTROLS AND PIPING
EXHAUST STACK
HIGH TEMP. REFRACTORY LINED REAR DOOR
DAVITED HINGED ACCESS DOORS (TUBES)
UL LISTED BURNER
FLAME SIGHT PORT
ALL A.S.M.E. CODE PIPING TO SECOND VALVE
FULLY AUTOMATED PROCESSOR
GAS, OIL OR COMBINATION FORCED DRAFT BURNERS
EXTRA HEAVY SKIDS AND SUPPORTS

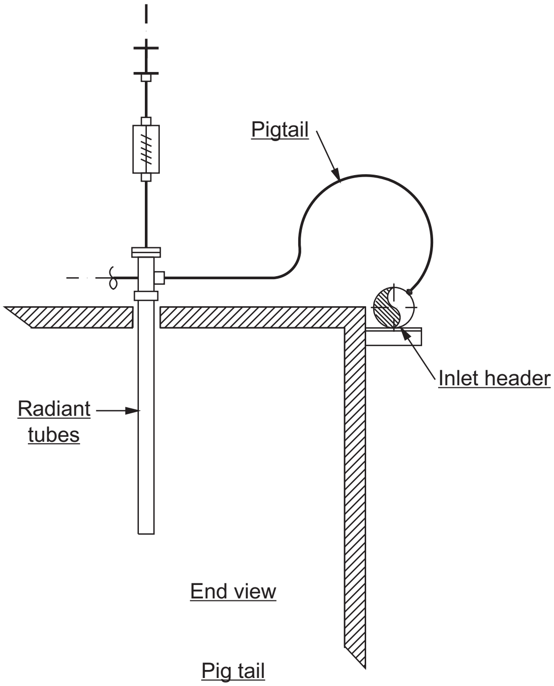


Schematic of burner head

Photograph of burner head

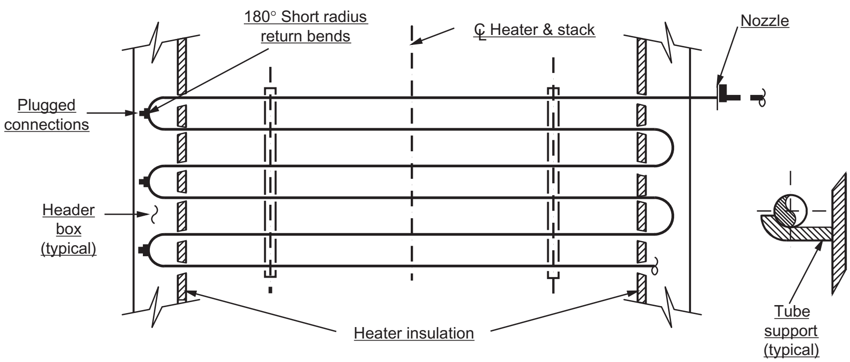
RADIANT COILS

The main compartment of a furnace is the radiant section. In the radiant section process streams are heated, usually in vertical tubes by heat from burners mounted in the walls, roof, or floor.



End view

Pig tail



Radiant tubes

9.5 COMBUSTION AIR PREHEATING SYSTEMS

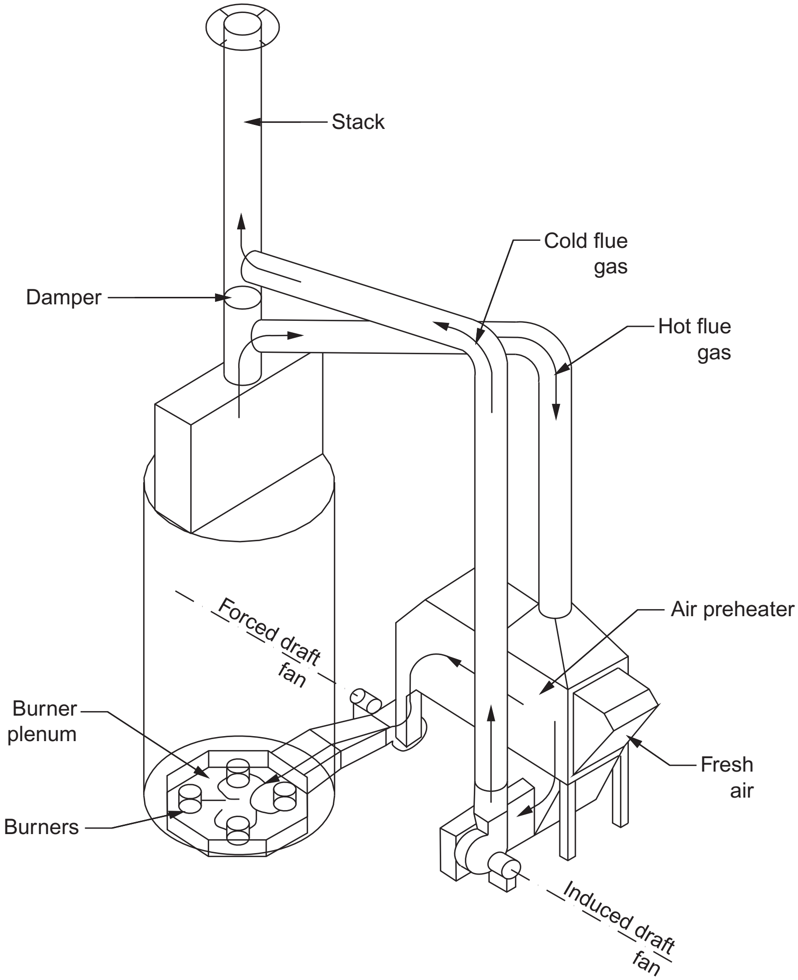
Thermal efficiency of a furnace can be improved if the air entering the radiant section around the burners is preheated.

The two most common preheating systems are:

- Regenerative
- Recuperative

REGENERATIVE

Hot flue gas leaving the convection section is diverted through a duct to a heat exchanger (air preheater) the incoming air is heated and Sent to the burner plenum by a force draft fan. The fan draws the flue gas through the preheater, and sends cooled gas back into the atmosphere through the stack.

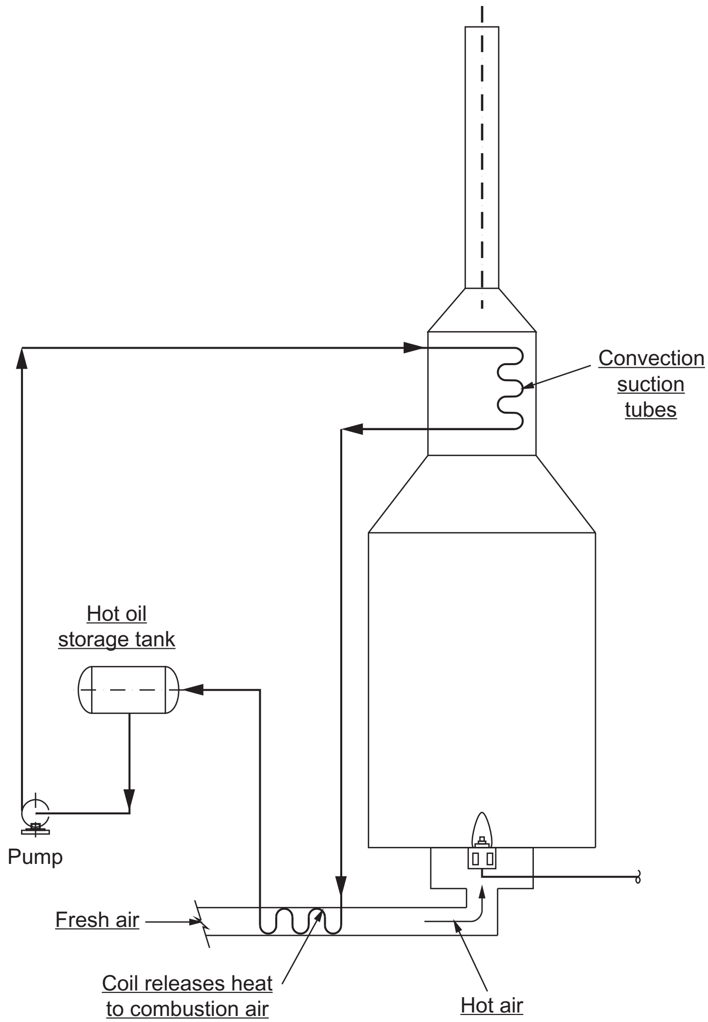


Regenerative

Combustion air preheating systems

RECUPERATIVE

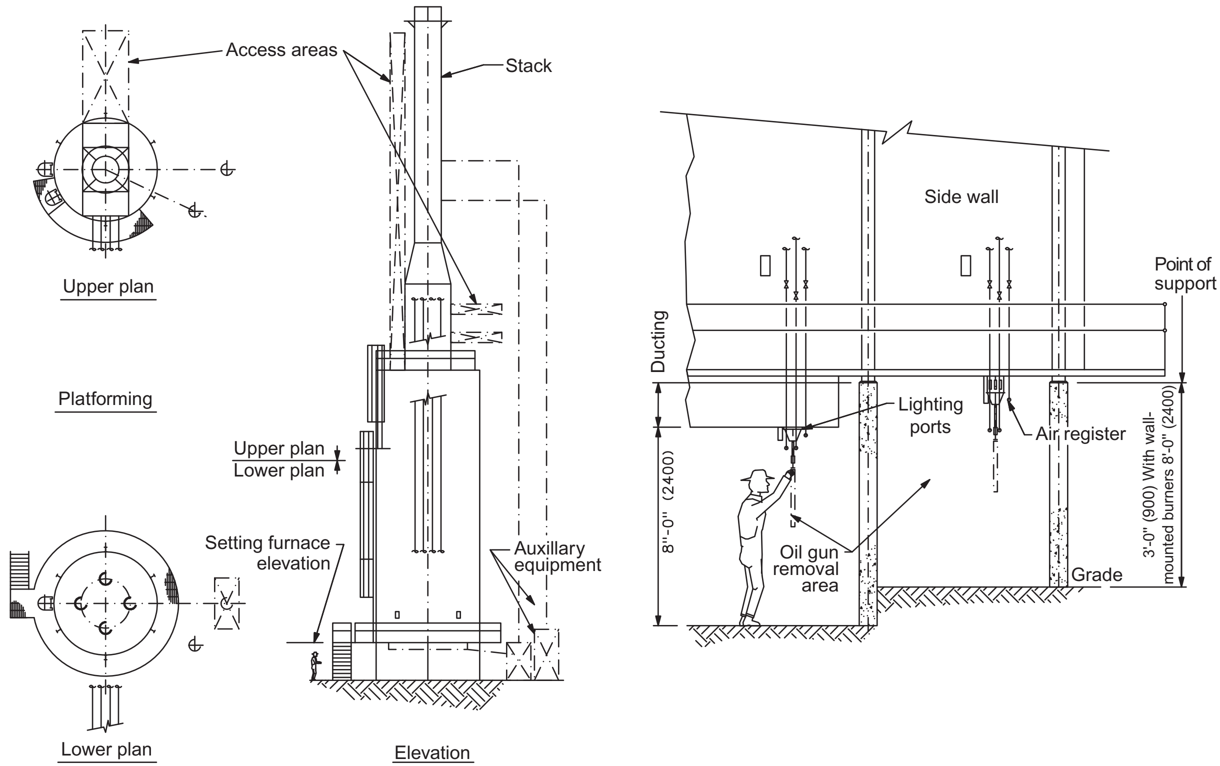
Oil is circulated through the convection section tube is heated and sent through the Inlet air duct, where it releases its heat. Hot air then enters the burner for combustion, and the hot oil is recirculated to a storage tank for recycling.



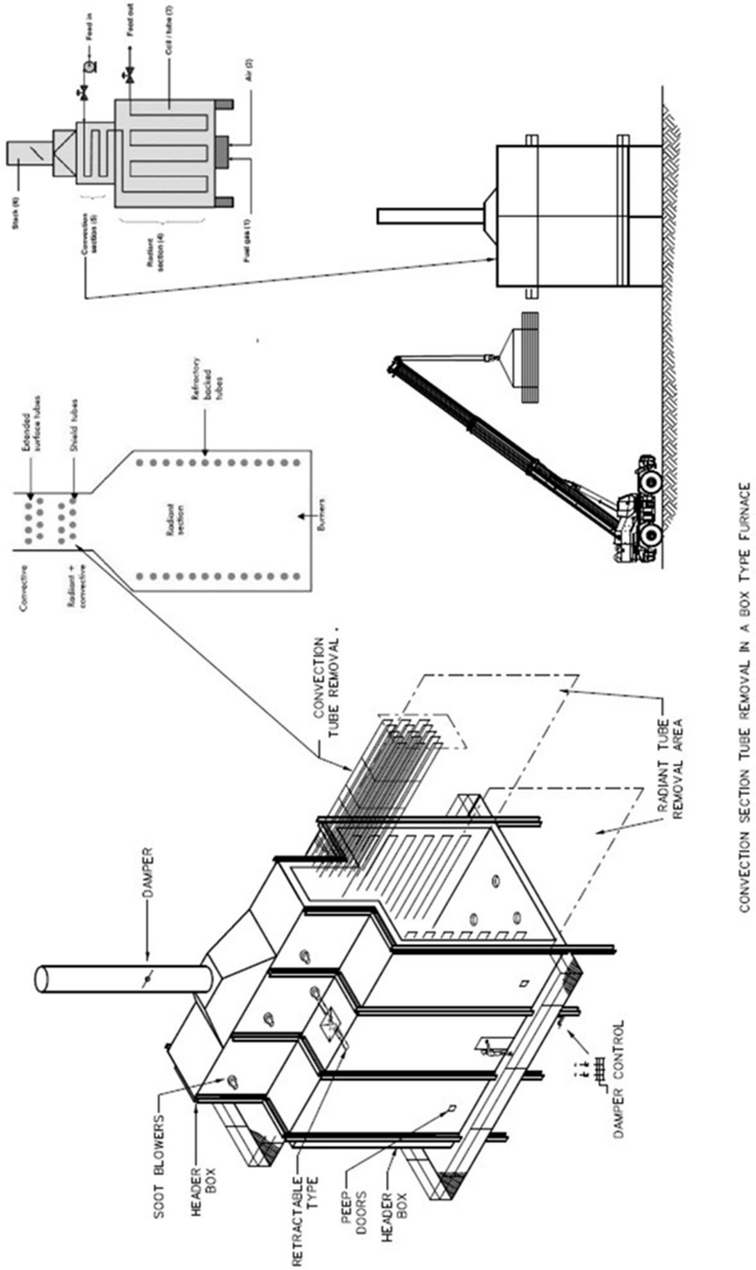
9.6 GENERAL ARRANGEMENT OF FURNACES

There are two primary factors that determine the furnace elevation:

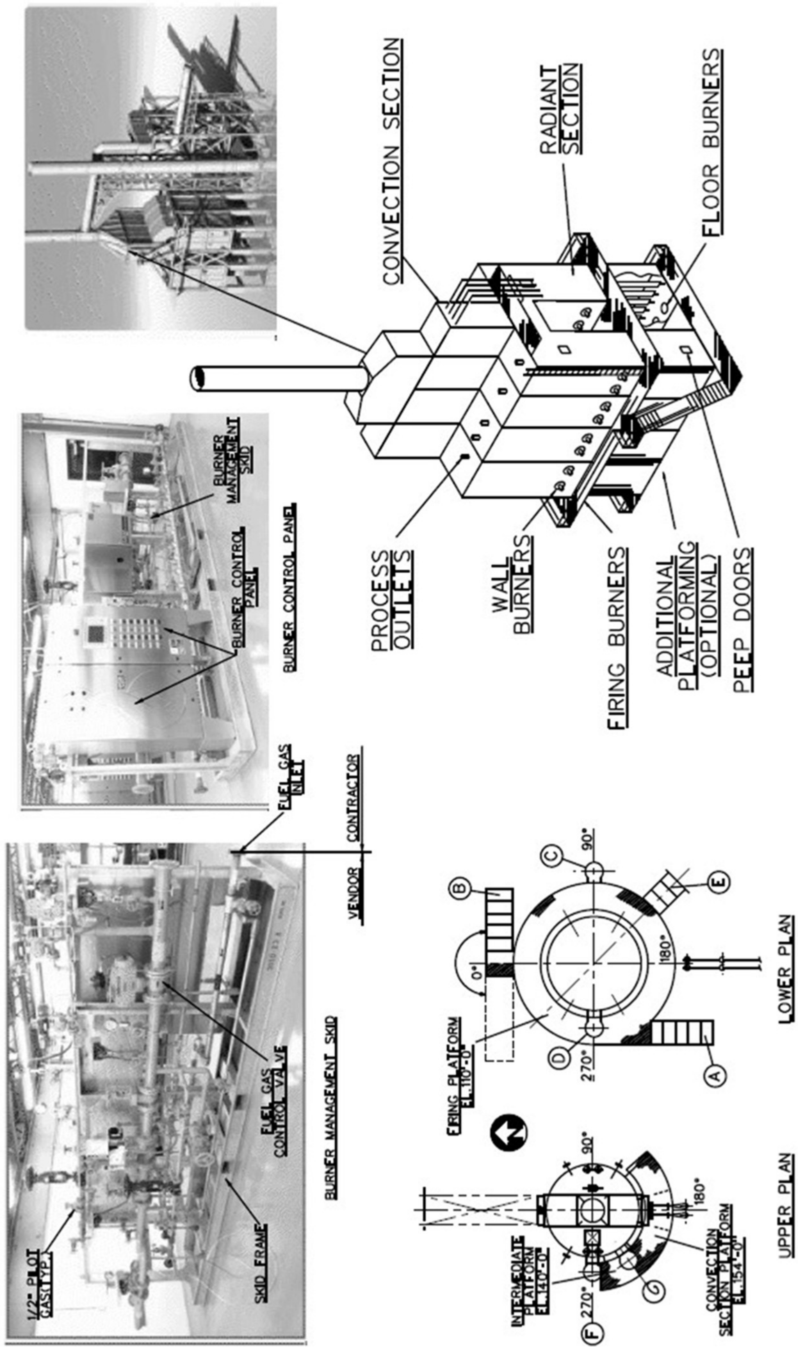
- Location of the burners
- Air preheating ducts if needed

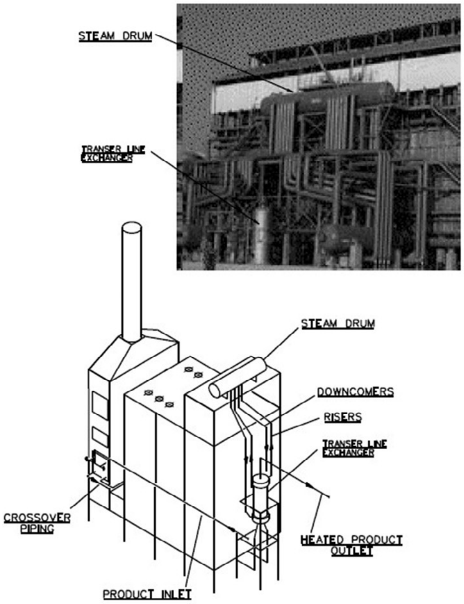


General arrangement of furnaces

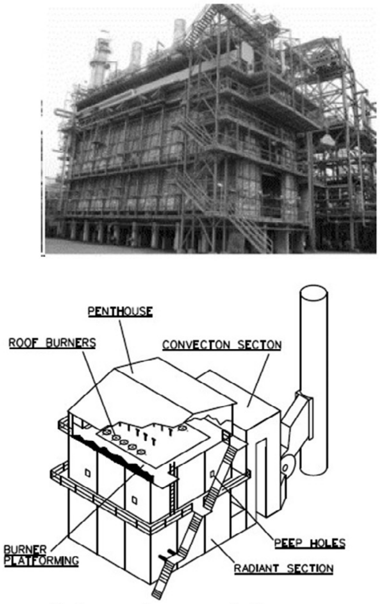


GENERAL ARRANGEMENT OF FURNACES


CONVECTION SECTION
RADIANT SECTION
FLOOR BURNERS
PROCESS OUTLETS
WALL BURNERS
FIRING BURNERS
ADDITIONAL PLATFORMING (OPTIONAL)
PEEP DOORS
BURNER MANAGEMENT SKID
BURNER CONTROL PANEL
BURNER CONTROL PANEL
FUEL GAS INLET
VENDOR
CONTRACTOR
1/2" PILOT GAS(TYP.)
SKID FRAME
FUEL GAS CONTROL VALVE
BURNER MANAGEMENT SKID
FIRING PLATFORM
LOWER PLAN
UPPER PLAN
INTERMEDIATE PLATFORM
CONVECTION SECTION PLATFORM

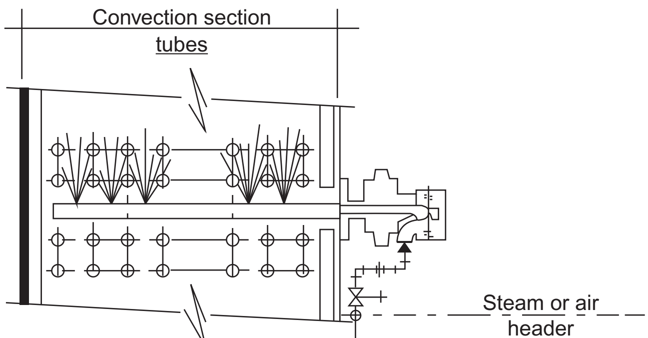


Steam drum and transfer line exchanger

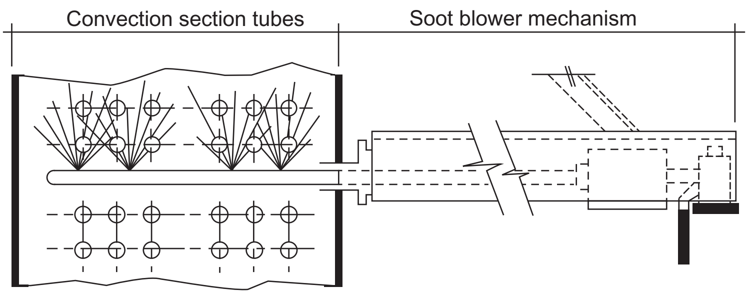


Reformer furnace platforms

SOOT BLOWERS



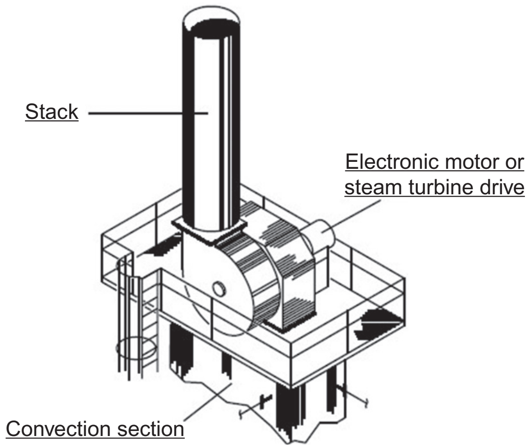
Fixed

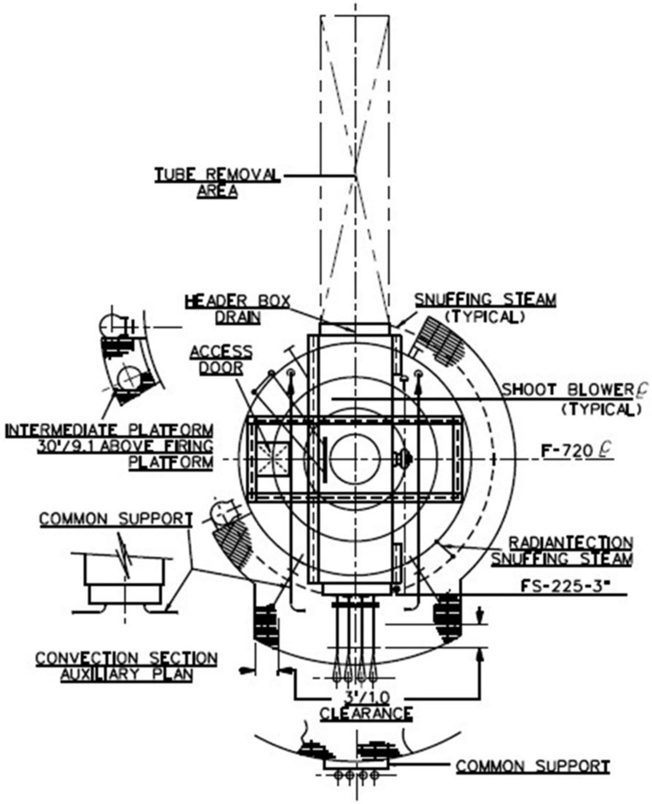


Retractable

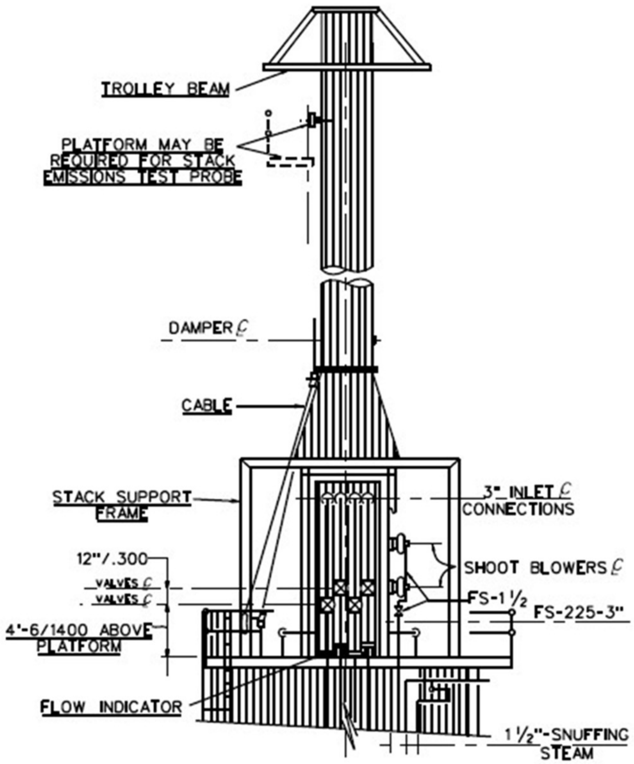
INDUCED DRAFT FAN

If an induced draft fan is required, platforms should be designed to enable adequate operation and maintenance.

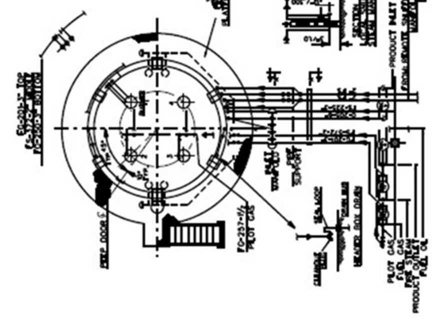




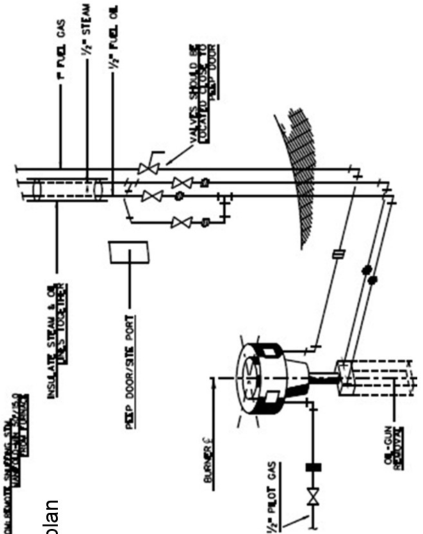
Circular furnace upper level plan



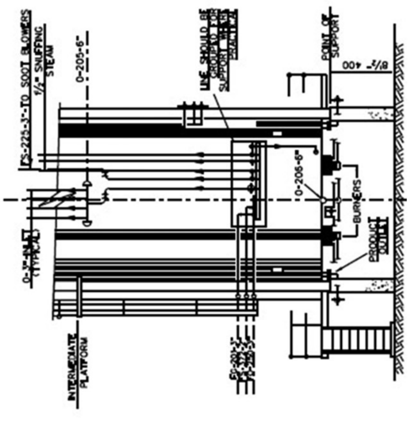
Circular furnace upper level elevation



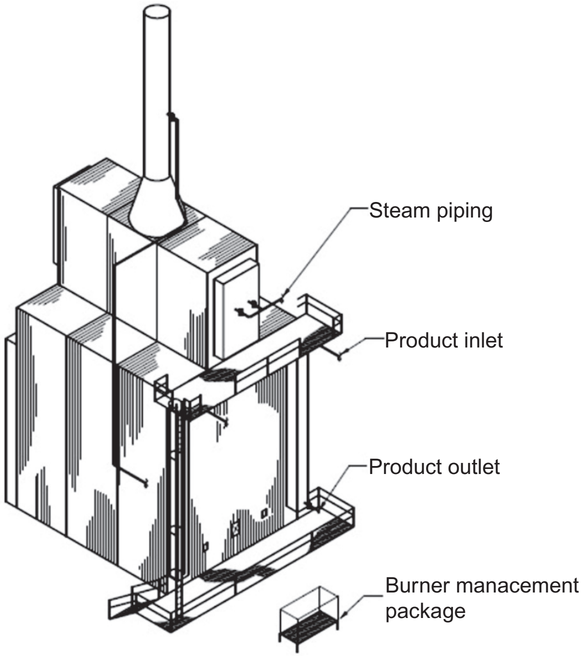
Lower level plan



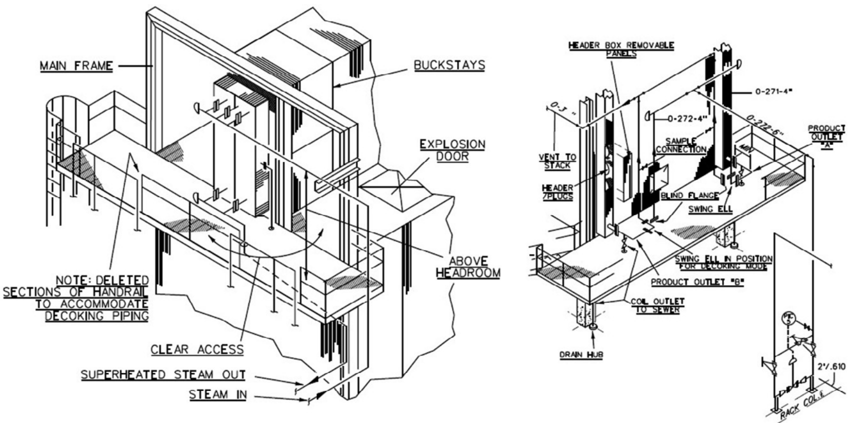
Burner piping detail



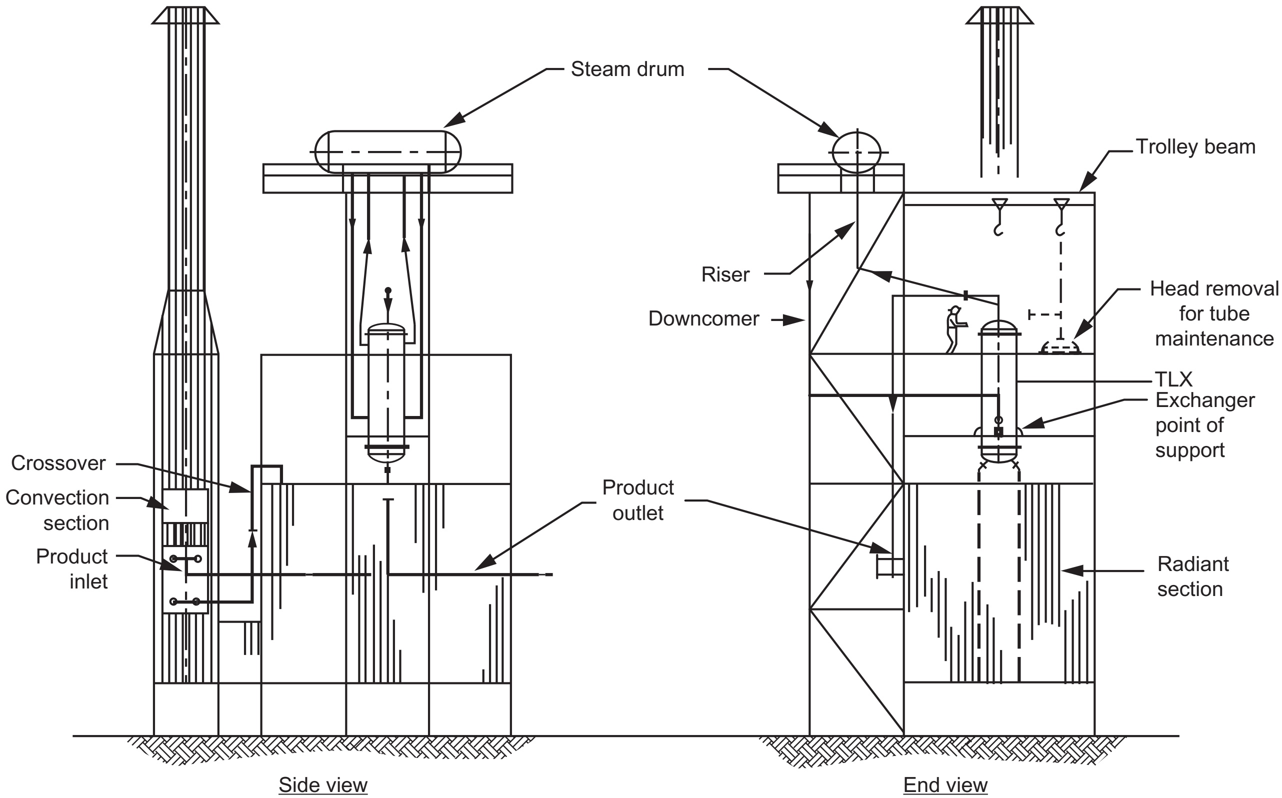
Lower level elevation



Box type furnace
Furnaces - piping layout



Decoking operation for box type furnace



Transfer line exchanger piping

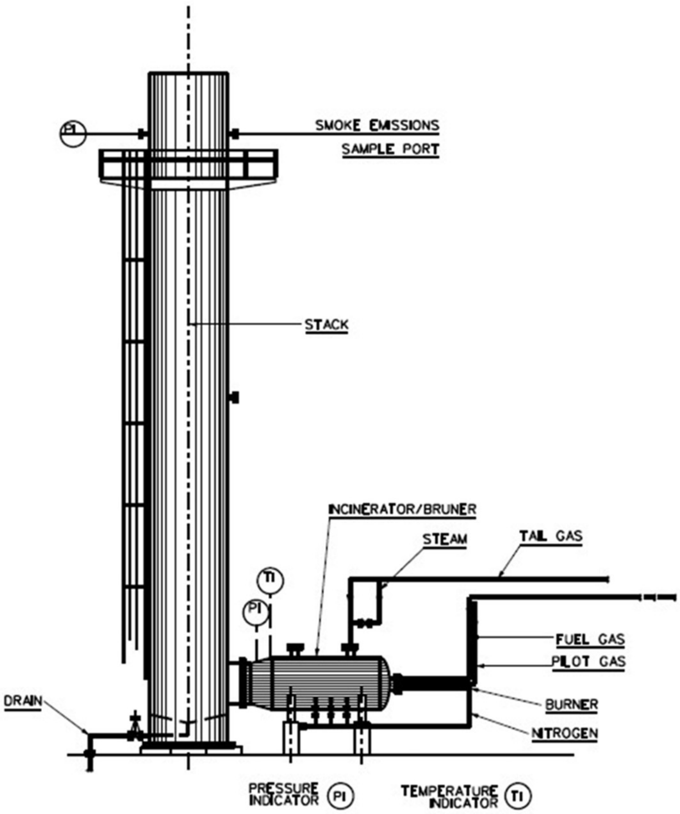
9.8 TAIL GAS INCINERATOR AND WASTE HEAT UNITS

TAIL GAS INCINERATOR

Waste gases that contain liquids must be disposed of.

For safety and environmental reasons they cannot be directed to the flare system.

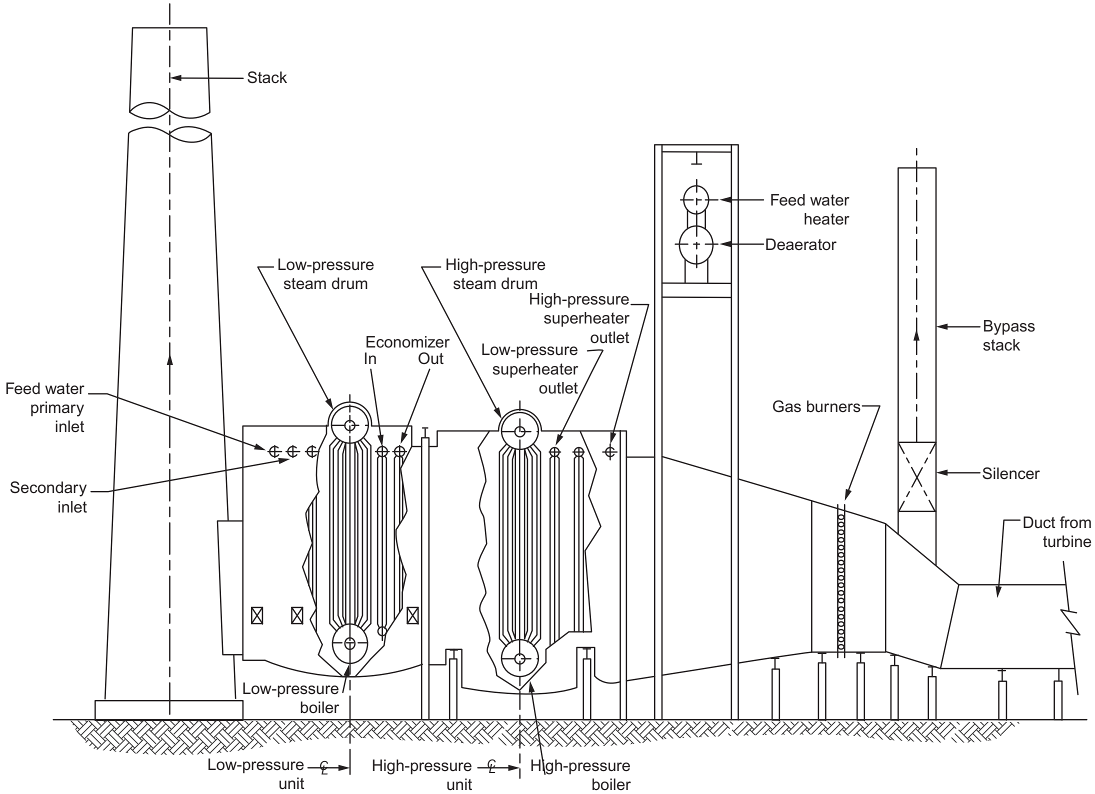
These gases must be burned in a **"Tail Gas Incinerator"**



TAIL GAS INCINERATOR

WASTE HEAT UNITS

Use the **waste gases (**800–1200°F/425–650°C) from a gas turbine to generate high- and low-pressure steam for plant use.



Waste heat recovery unit

CHAPTER

Reactors

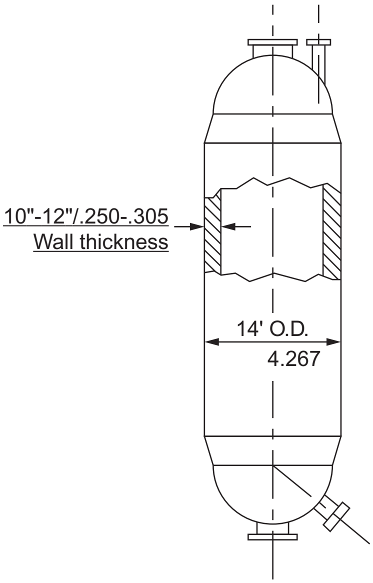
10

10.1 DESCRIPTION

Reactors contain catalysts. They are used in process facilities to transform the process feed, or to remove an undesired material from the feed. Reactors operate under very high temperatures and pressures. Reactors are usually of a vertical design. Due to the high temperatures and pressures and the corrosive effects of the catalyst, the majority of reactors are manufactured from stainless and high alloy steels, and they have a very thick wall thickness.

The principal layout requirements for reactors are:

- Loading
- Unloading
- Inlet and outlet nozzles and valve arrangements at reactor



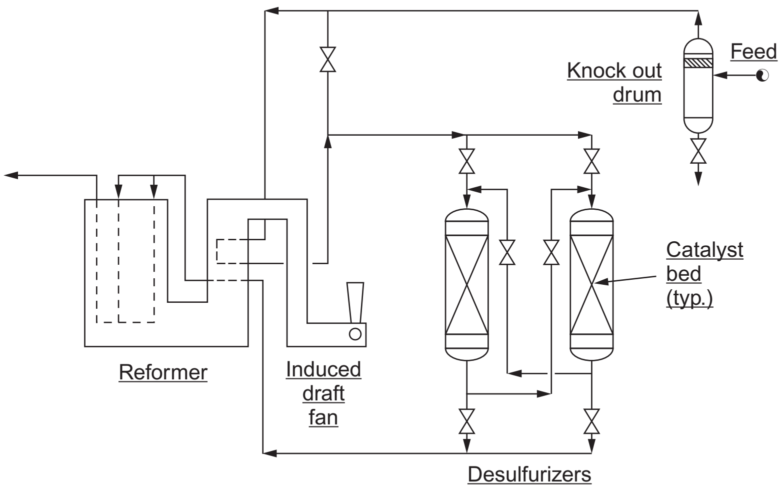
The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00010-2

10.2 PROCESS OPERATION

Basically reactors area catalyst charged pressure vessel.

Two common examples are:

- **Desulfurizers**—they usually operate with a twin vessel and are used for the removal of sulfur from feedstock by absorbing sulfur on the internal catalyst. As the catalyst reaches sulfur saturation regeneration takes place, and the spent catalyst is refurbished.

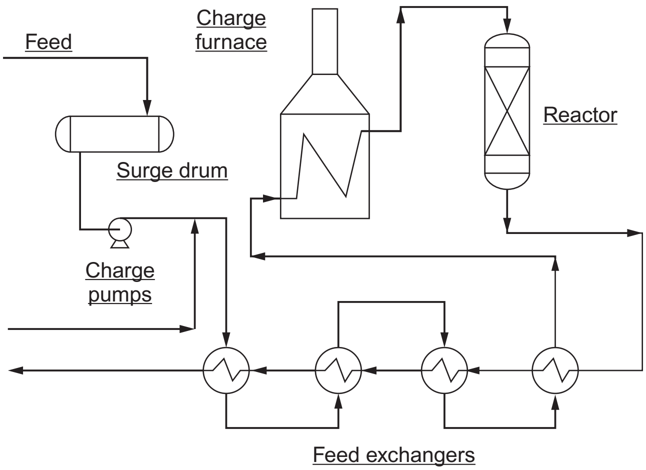


- **Methanators**—these are used in methanol and catalytic reforming units, these are spherical and vertically mounted vessels with elliptical heads. Connections on these are limited to inlet, outlet, and maintenance access, unloading, sample, temperature, and pressure connections.

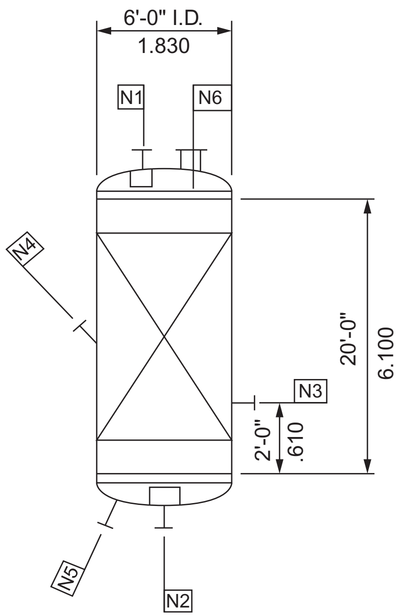
10.3 DESIGN CONSIDERATIONS

Reactor internals have:

- Bed supports, Screens Inlet baffles, Outlet connectors, Catalysts, and inert materials

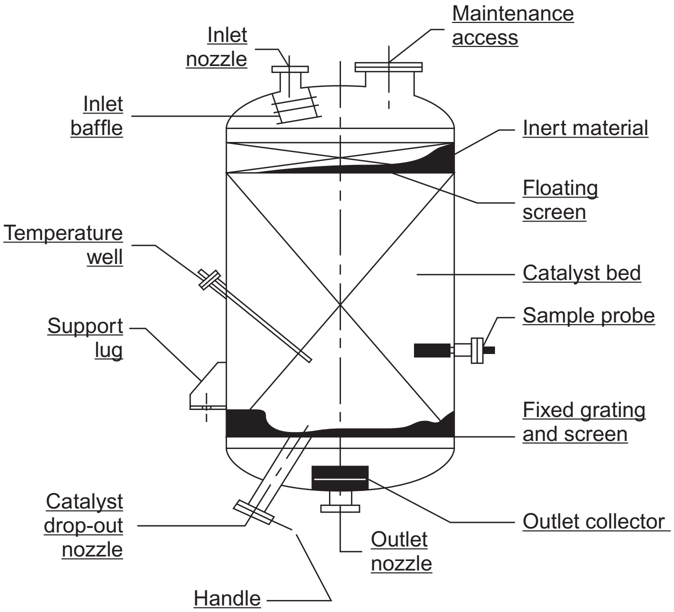


Except for **reactors** used in **methanol service** and **catalytic reforming** units, most reactors are vertically mounted with elliptical heads. Nozzle requirements for the reactor will be supplied by the Process Engineering Department. Nozzle requirements and dimensions will be furnished on a **process vessel sketch**.



Nozzle summary		
Symbol	Size	Service
N1	8" 600+ RF	Inlet
N2	8" 600+ RF	Outlet
N3	3" 600+ RF	Sample
N4	1" 600+ BJ	Temperature
N5	12" 600+ RF	Catalyst drop out
N6	24" 600+ RF	Maintenance access

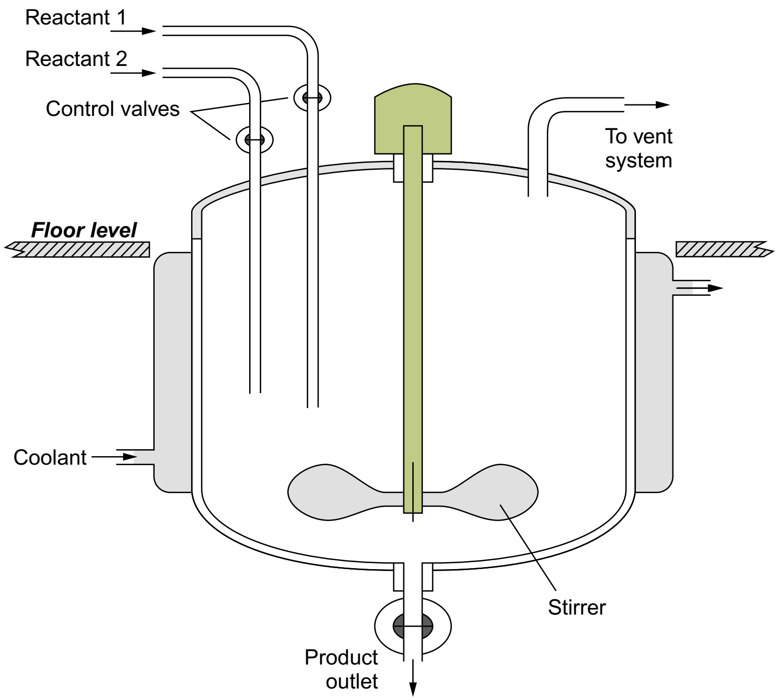
Process vessel sketch (reactor)



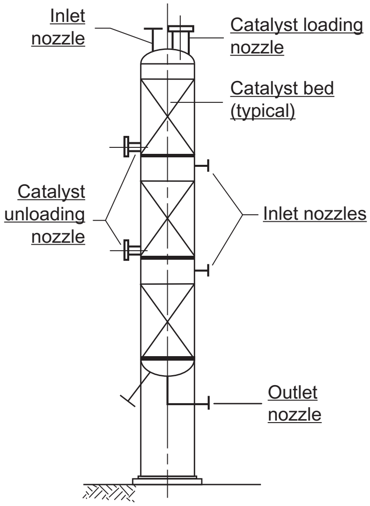
Reactor drawing

Design considerations—Reactors with cooling jacket

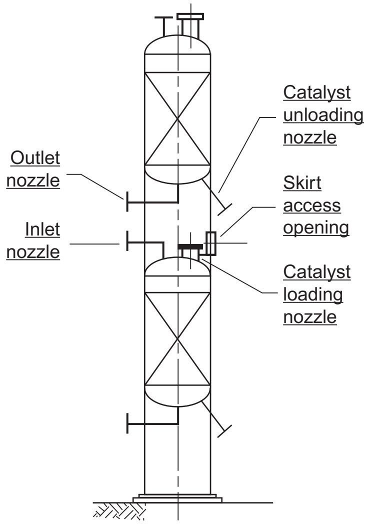
Reactor with cooling jacket (photo)



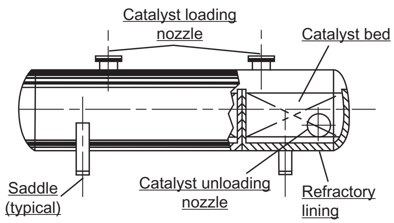
Schematic — Reactor with cooling jacket



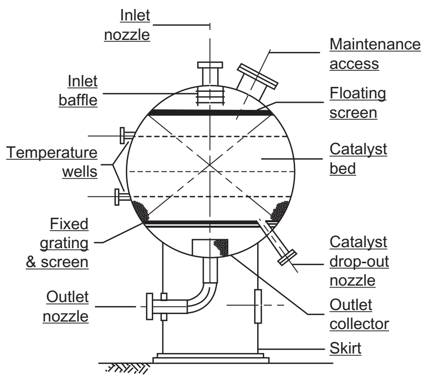
Multibed reactor



Stacked reactors



Horizontal reactor



Spherical reactor

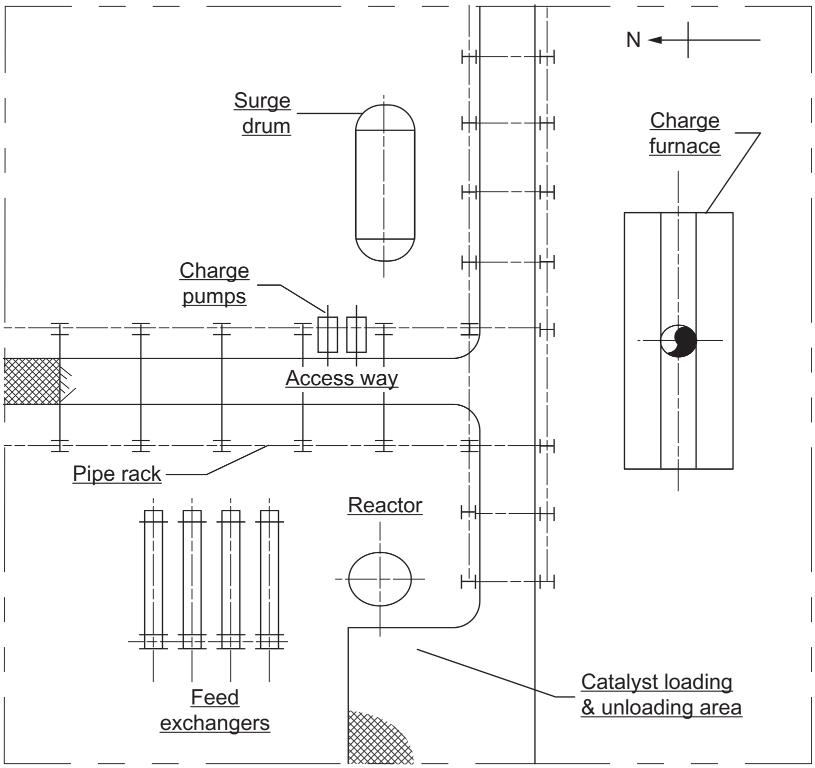
10.4 REACTOR LOCATIONS

Reactors are located adjacent to their related equipment.

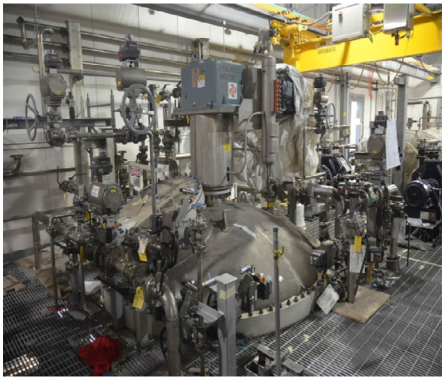
Locations are determined by:

- Operation—access to valves and instrumentation.
- Catalyst loading and unloading.

- Reactors operate close to a furnace and in sequence so that the high-temperature piping runs are minimized.



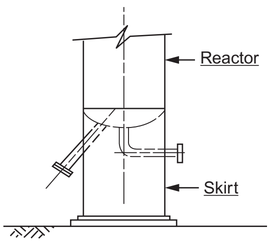
Partial plan showing location of reactor (in open area)



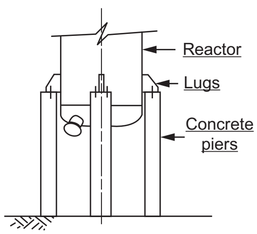
Reactor locations — showing top head of reactor access platform area (in closed structure)

(Fluid Catalytic Cracking)

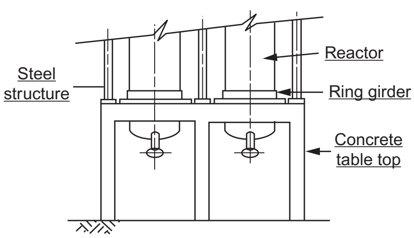
10.5 SUPPORT AND ELEVATION



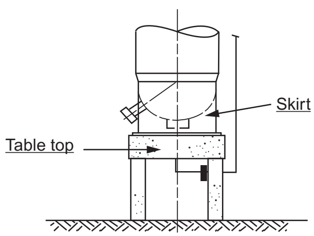
(A) Skirt supported (foundation)



(B) Lug supported

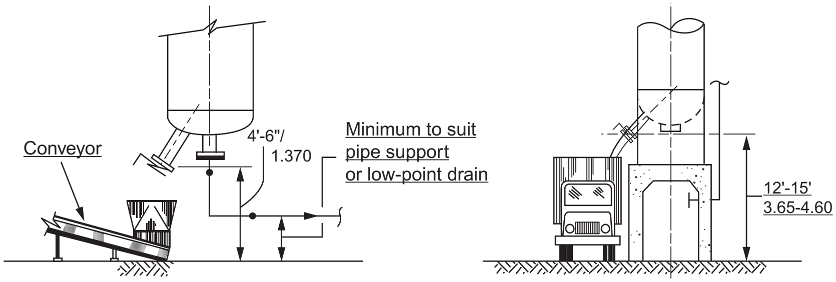


(C) Ring girder supported



(D) Skirt supported (table top)

The elevation of a **reactor** is dictated by the catalyst loading and unloading nozzle and the clearance required for the outlet piping.



The elevation of a reactor is set by the following:

- Size (dimensions) of reactor
- Head types
- Support details
- Size of outlet (bottom)
- Unloading nozzle size
- Catalyst handling (client preferences)

10.6 NOZZLE LOCATIONS AND ELEVATIONS

Reactor nozzles are located to suit:

- Process requirements
- Economic piping runs
- Piping flexibility
- Functional nozzle locations

Information required locating the location and elevation of reactor nozzles are:

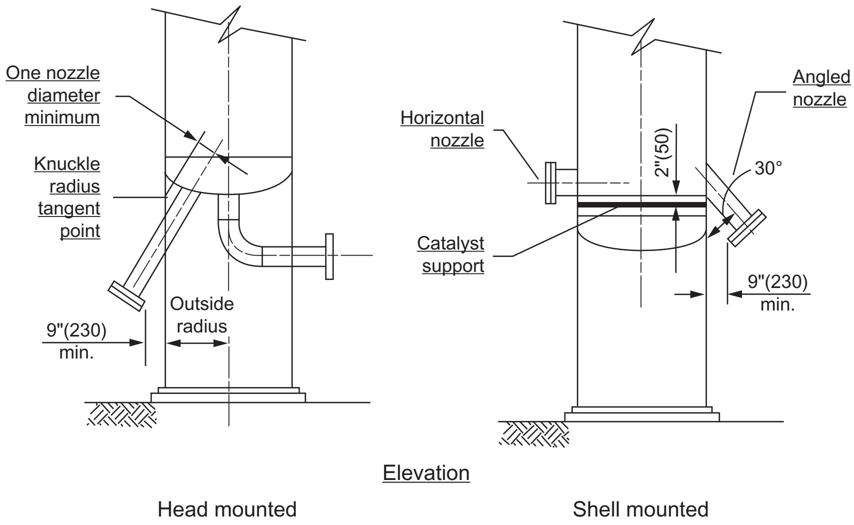
- Process vessel sketch
- P&ID
- Instrument vessel sketch
- Piping Line list
- Nozzle summary
- Piping specifications

- Layout specifications
- Insulation requirements

Nozzles located on the top head:

- Process Inlet (on small reactors can also be used for catalyst loading)
- Maintenance access (used for catalyst loading)

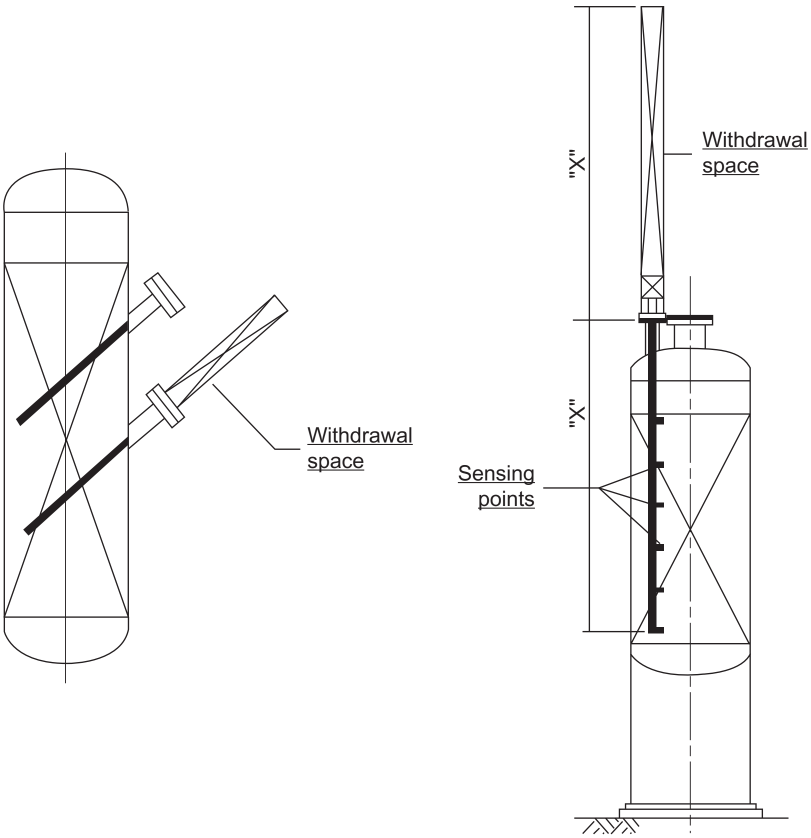
CATALYST UNLOADING NOZZLES



NOZZLE LOCATIONS AND ELEVATIONS

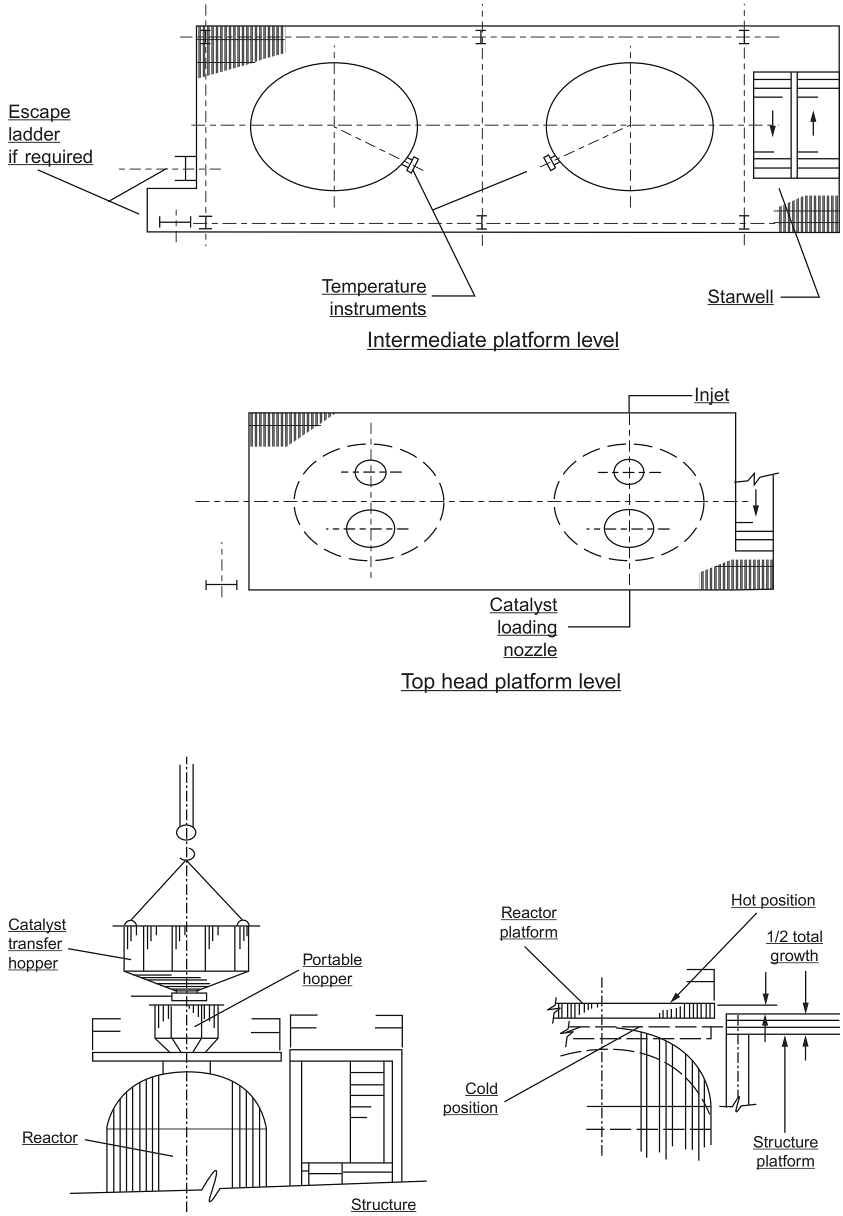
Temperature connections:

Temperature instruments are used to measure the temperature at different levels of the catalyst bed.

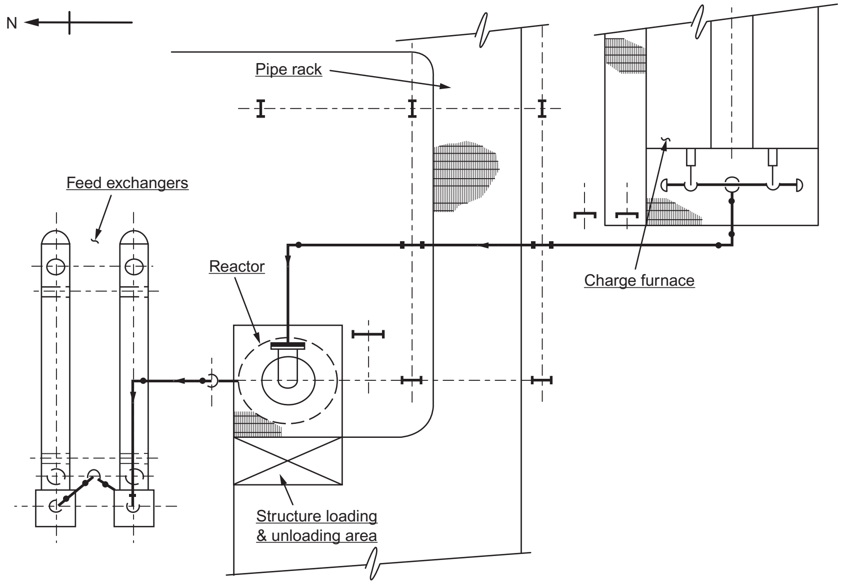


To minimize multiple connections standpipe with multiple connections can be used and inserted into the reactor from the top in a well.

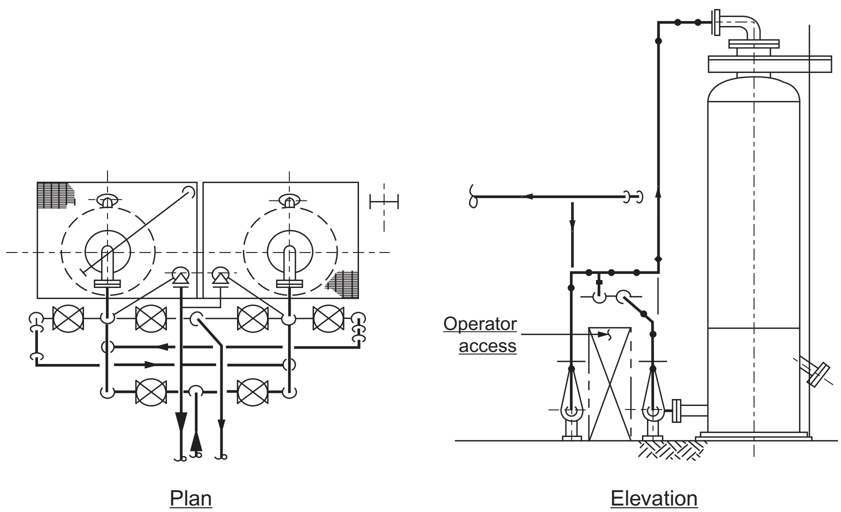
10.7 PLATFORM AND PIPING ARRANGEMENTS



Platform and piping arrangements



Piping arrangement for a single reactor

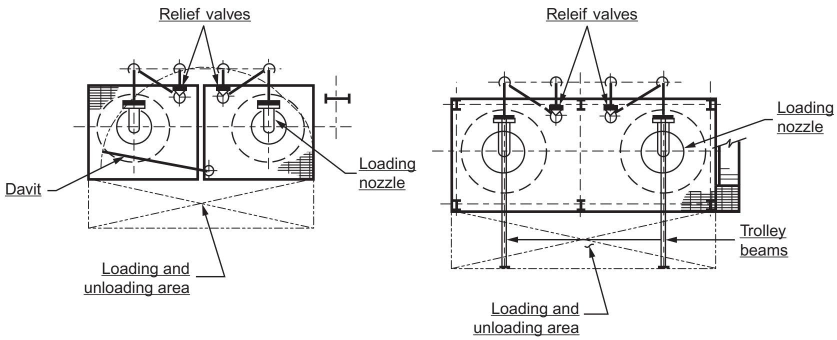


Reactors in series with manually operated valve manifolds

10.8 MAINTENANCE

Handling for catalyst loading and the removal of items such as relief valves and valve drives can be achieved by the use of either:

- Fixed handling devices
- Mobile handling devices



Catalyst is removed infrequently, and is done during shutdowns and is accomplished by allowing the catalyst to cool down and then emptying the catalyst through the bottom unloading nozzle.

CHAPTER

Towers

11

11.1 DISTILLATION PROCESS

Distillation (separation) is the process of partially vaporizing a liquid mixture.

There are three types of distillation: Basic, **Fractional**, and Destructive.

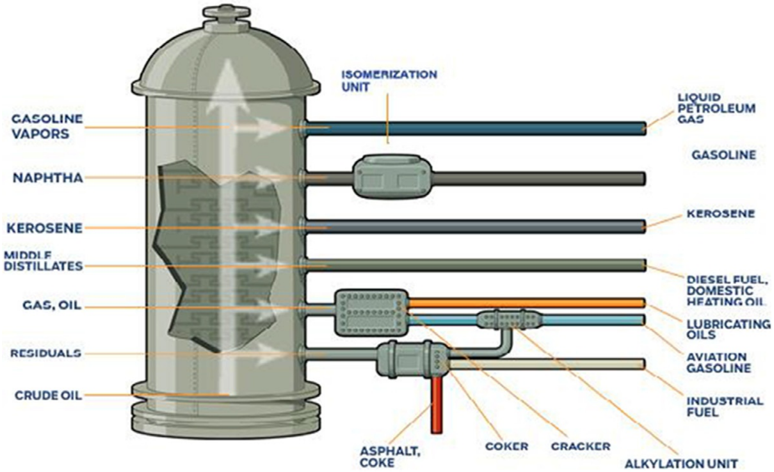
The type of distillation used in the oil and gas industries is **"Fractional."**

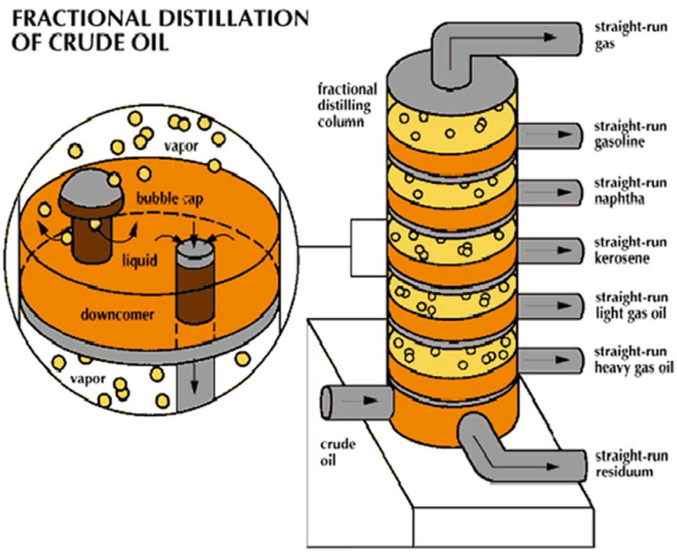
Vapors are condensed and the individual components of the mixture separated. By increasing the temperature of the crude oil, the initial boiling point (IBP) is reached.

AS boiling continues and the temperature rises the lightest material in the crude—**butane** is the first product to be produced because its IBP is a little below 100°F/38°.

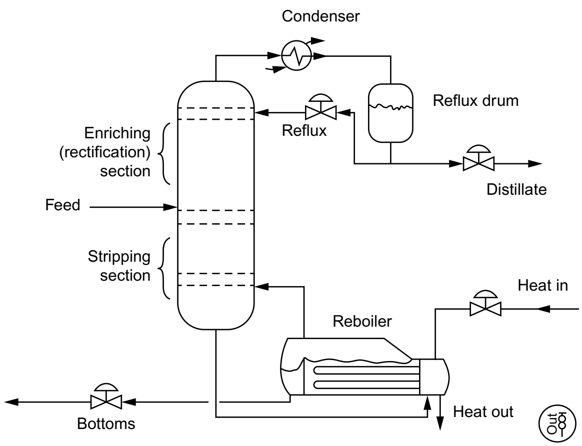
Heavier materials are then produced below 800°F/427°C. Anything above 800°F/427°C is regarded as "Residue."

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00011-4

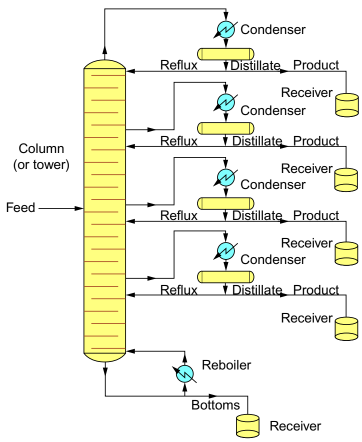

ISOMERIZATION UNIT
GASOLINE VAPORS
NAPHTHA
KEROSENE
MIDDLE DISTILLATES
GAS, OIL
RESIDUALS
CRUDE OIL
LIQUID PETROLEUM GAS
GASOLINE
KEROSENE
DIESEL FUEL, DOMESTIC HEATING OIL
LUBRICATING OILS
AVIATION GASOLINE
INDUSTRIAL FUEL
ASPHALT, COKE
COKER
CRACKER
ALKYLATION UNIT


FRACTIONAL DISTILLATION OF CRUDE OIL
vapor
bubble cap
liquid
downcomer
vapor
fractional distilling column
straight-run gas
straight-run gasoline
straight-run naphtha
straight-run kerosene
straight-run light gas oil
straight-run heavy gas oil
crude oil
straight-run residuum

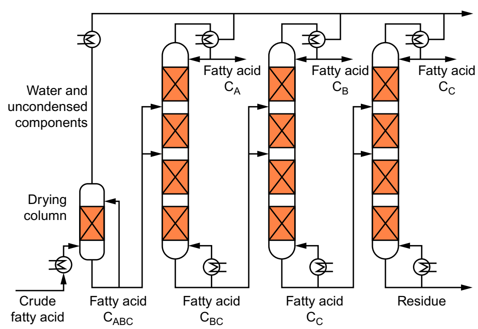
There are three types of distillation processes:



Batch shell distillation



Continuous shell distillation



Multipurpose fatty acid distillation plant

Multiunit fractional distillation

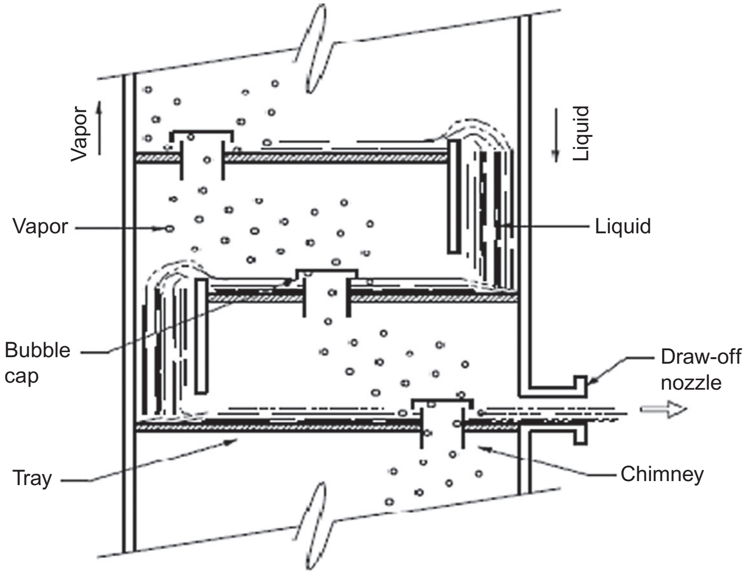
11.2 TYPES OF TOWER

11.2.1 PACKED TOWER

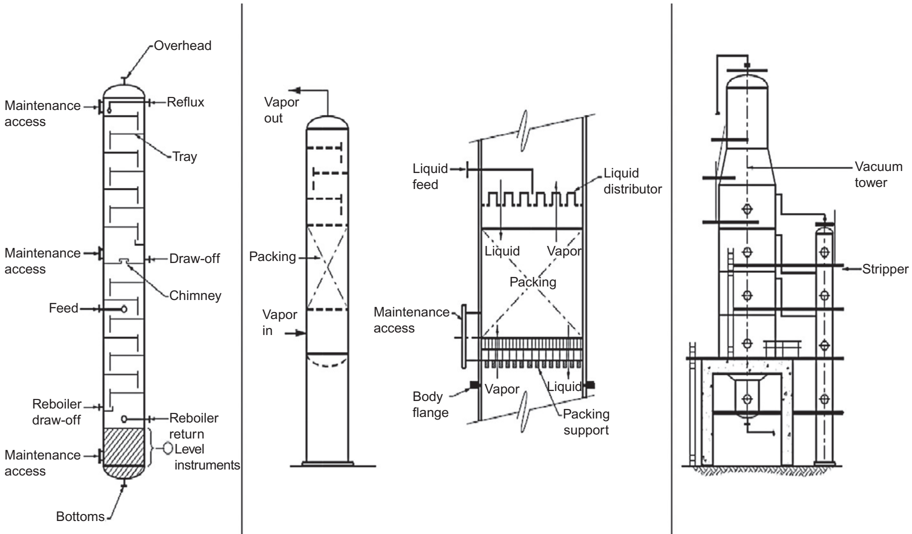
A packed tower is filled with a catalyst or other type of packing material such as ceramics, metals, and clays.

11.2.2 TRAYED TOWERS

A trayed tower is filled with trays of either **perforated plate** or "**bubble cap design**"



Trayed tower



Trayed tower   Packed tower   Crude oil vacuum tower

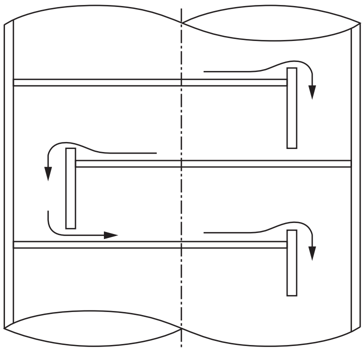
Types of tower

Trayed Tower   Packed Tower   Crude Oil Vacuum Tower

11.3 DESIGN CONSIDERATIONS

Types of trays:

- Perforated trays
- Bubble caps

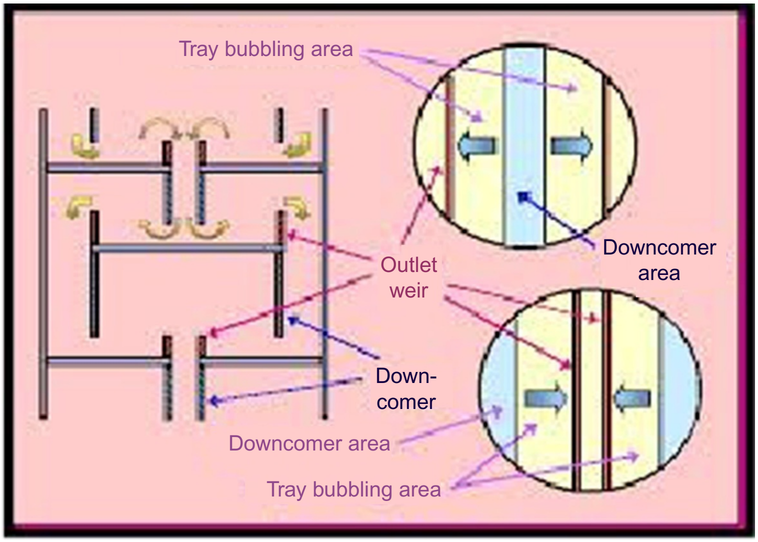


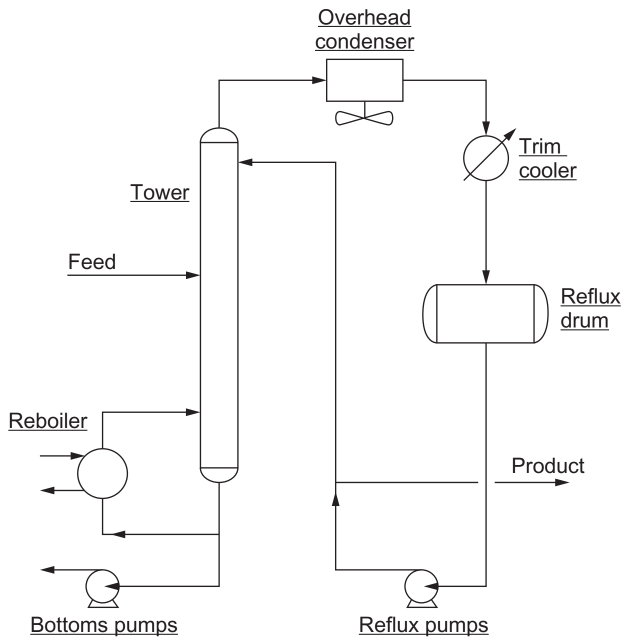
Single down flow tray

Internals:

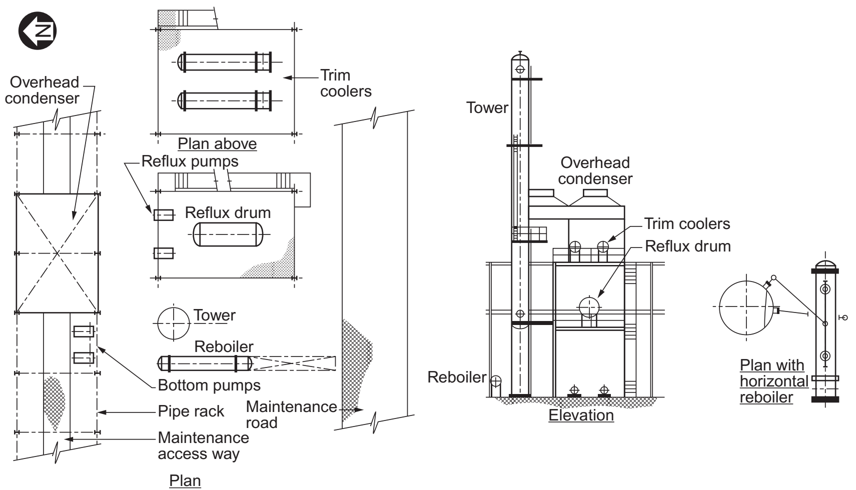
- Funnels
- Cyclones

Double down flow tray:

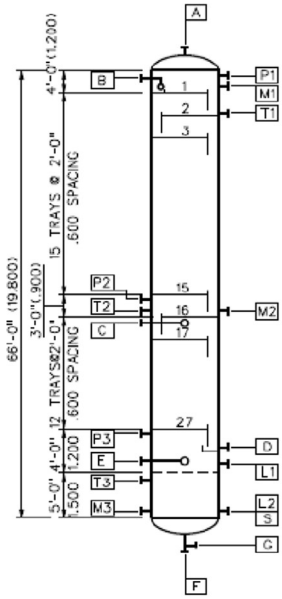




PFD
Reflux drums and reboilers

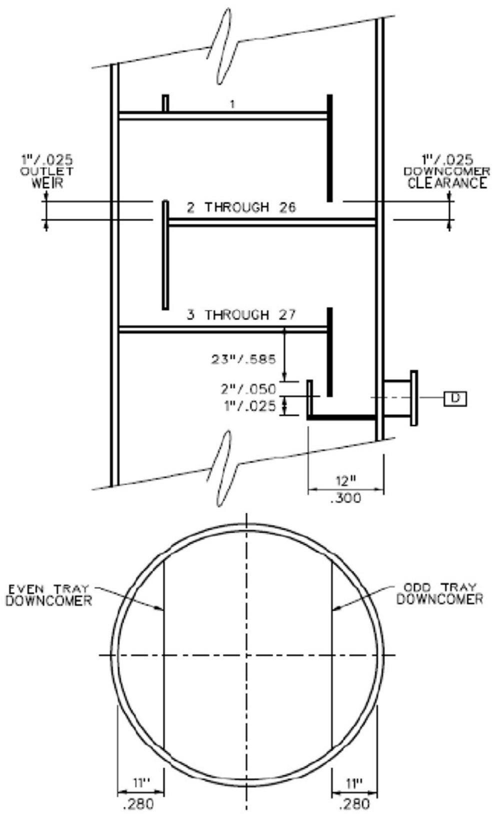


Reflux drums and reboilers



PROCESS TOWER SKETCH

NOZZLE SUMMARY		
SYMBOL	SIZE & RATING	SERVICE
A	18"-150#RF	VAPOR
B	3"-150#RF	REFLUX
C	6"-150#RF	FEED
D	10"-150#RF	REBOILER DRAW-OFF
E	10"-150#RF	REBOILER RETURN
F	6"-150#RF	BOTTOMS OUTLET
P	1"-150#RF	PRESSURE
T	1"-150#RF	TEMPERATURE
L	2"-150#RF	LEVEL
S	1"-150#RF	STEAM OUT
M	24"-150#RF	MAINTENANCE ACCESS
G	3"-150#RF	DRAIN



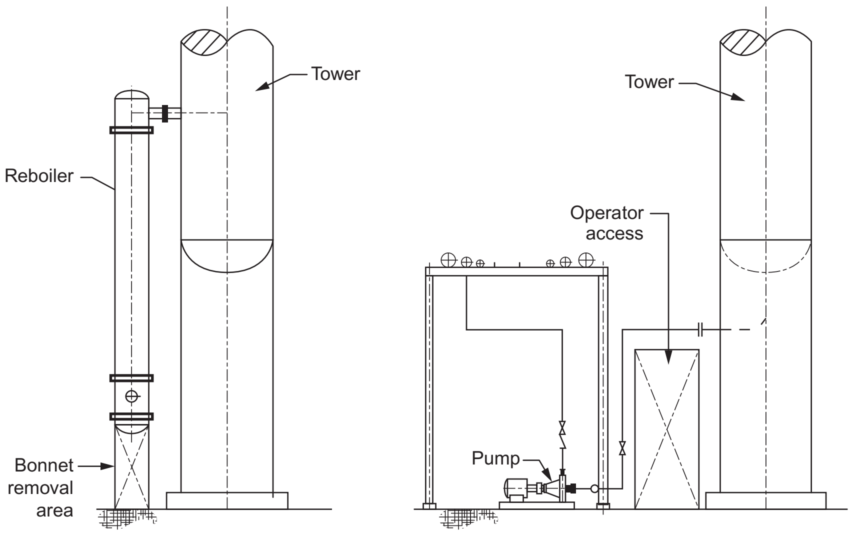
TRAY DETAILS

11.4 ELEVATIONS AND SUPPORTS

The bottom tangent line elevation of the tower is the first information to be established when setting a tower elevation.

This is established after all the following information has been taken into account:

- Process vessel sketch
- Vessel connection summary
- NPSH requirements
- Tower dimensions
- Head type
- Fireproofing details
- Insulation requirements
- Support details
- Bottom outlet size
- Reboiler details
- Foundations
- Minimum clearances
- Operator access
- Maintenance access



Elevations and supports

11.5 NOZZLE LOCATIONS AND ELEVATIONS

Nozzles are located based on:

- Tower internal requirements

Nozzles are orientated based on:

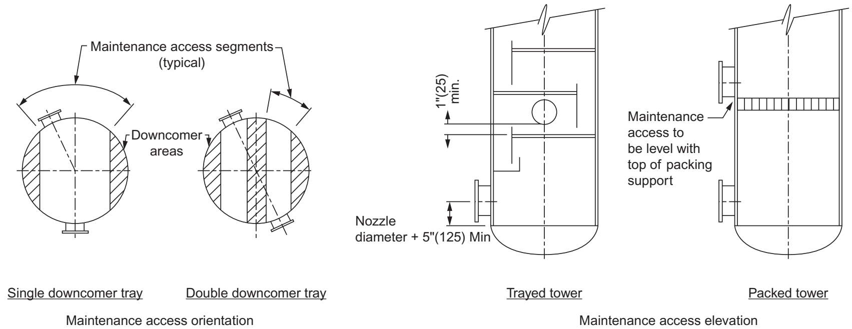
- Maintenance and operational requirements

The **location of nozzles** should also facilitate the **most economic** and **orderly connection of the piping** between the tower and associated equipment.

Maintenance access will need to be located, and the usual locations for these are:

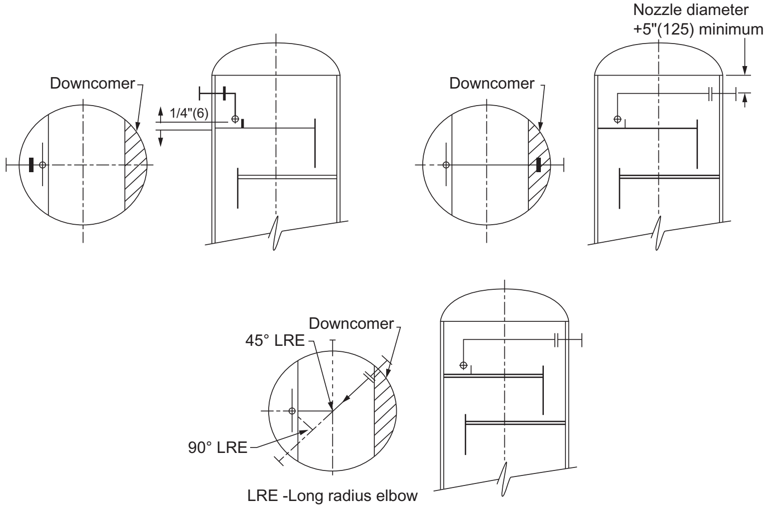
- Bottom section, intermediate section, and top section

Maintenance access must **not** be located at down comers



Nozzle locations and elevations

INLET NOZZLES



INLET Nozzles

Nozzle locations and elevations

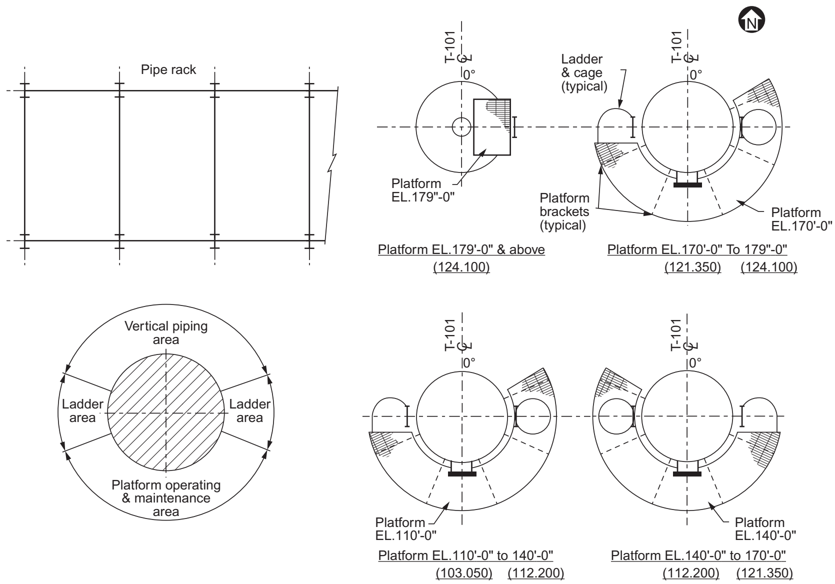
11.6 PLATFORM ARRANGEMENTS

Platform arrangements are set by:

- Items that require operation
- Items that require maintenance
- ladder run requirements set by OSHA (30 ft/9.15 m)

Platform widths are set by:

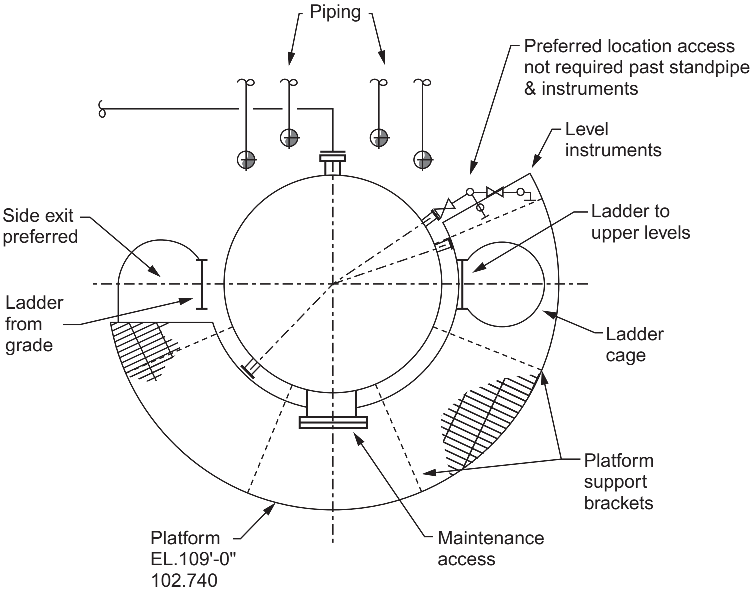
- Operator access with need for control operation min (3 ft/9 m)
- Congested platforms min width (3 ft/9 m) plus width of controls



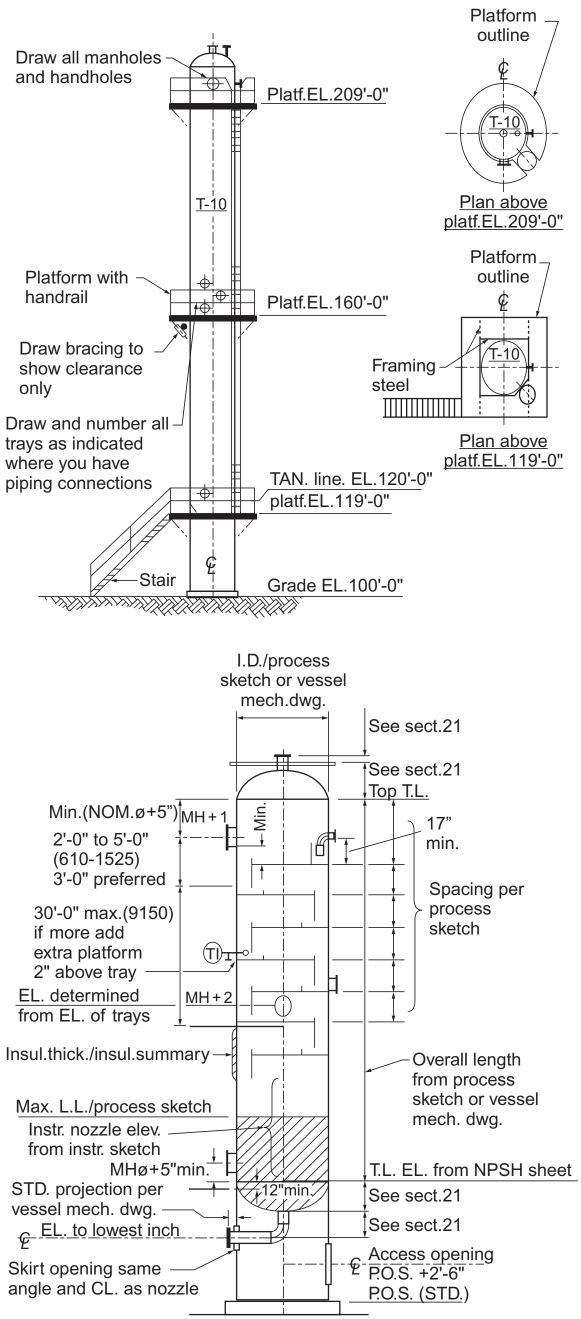
Platform arrangements

CIRCULAR PLATFORM BRACKET SPACING

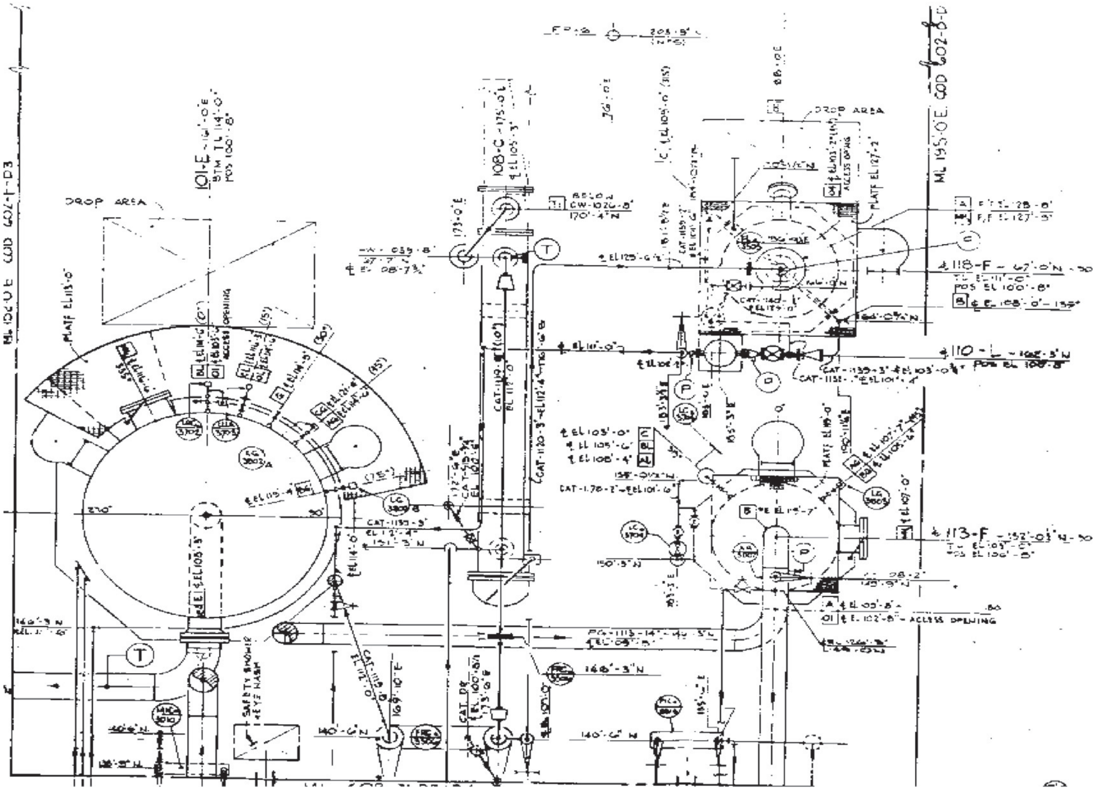
Vessel Inside Diameter	Bracket Spacing (Degrees)	Angle (Degrees) Between Ladders and Adjacent Bracket
Less than 3′-0″ (915 mm)	60	30
3′-0″ to 7′-5″ (915 mm to 2.3 M)	45	22½
7′-6″ to 16′-5″ (2.3–5 M)	30	15
16′-6″ to 24′-11″ (5–7.6 M)	22 ½	11¼
25′-0″ to 33′-0″ (7.6–10.0 M)	18	9



Platform arrangements



Tower platforms and ladders



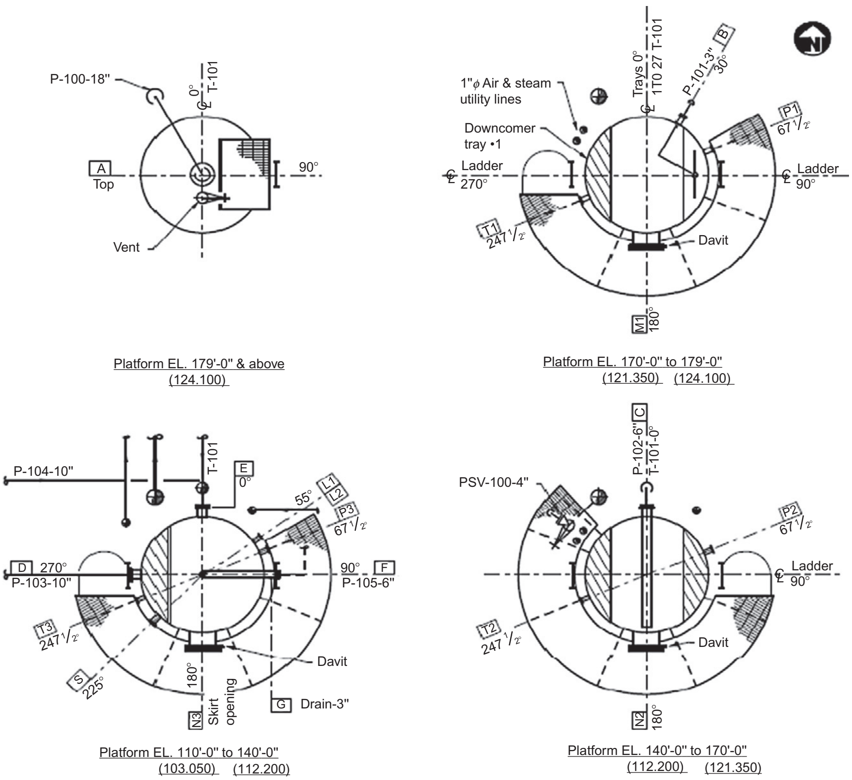
2D Piping Arrangement (circa 1980's) drawing showing Tower, Exchanger and Drums

Photo of Fractionation Towers

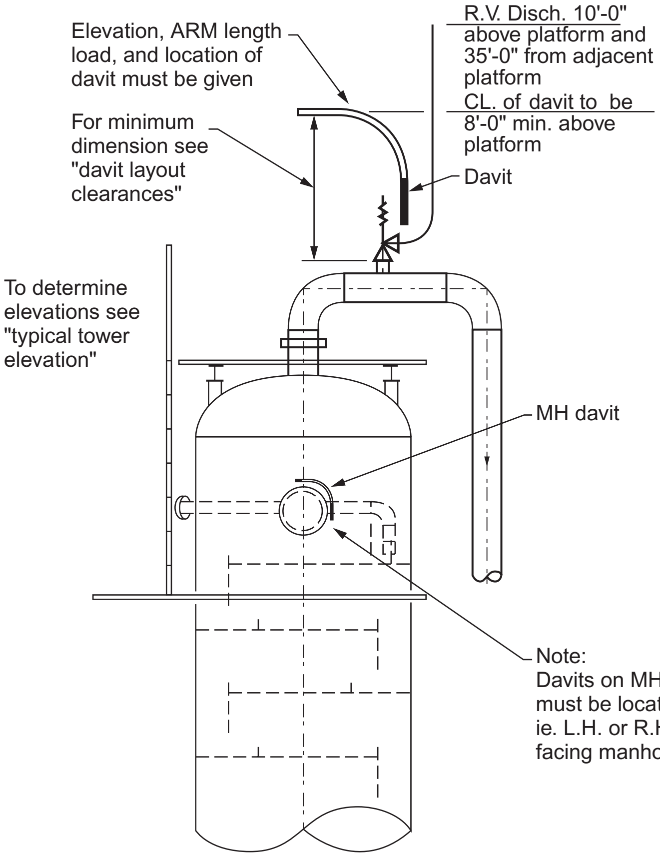
Top Head Platform at Tower

11.7 TOWER PIPING

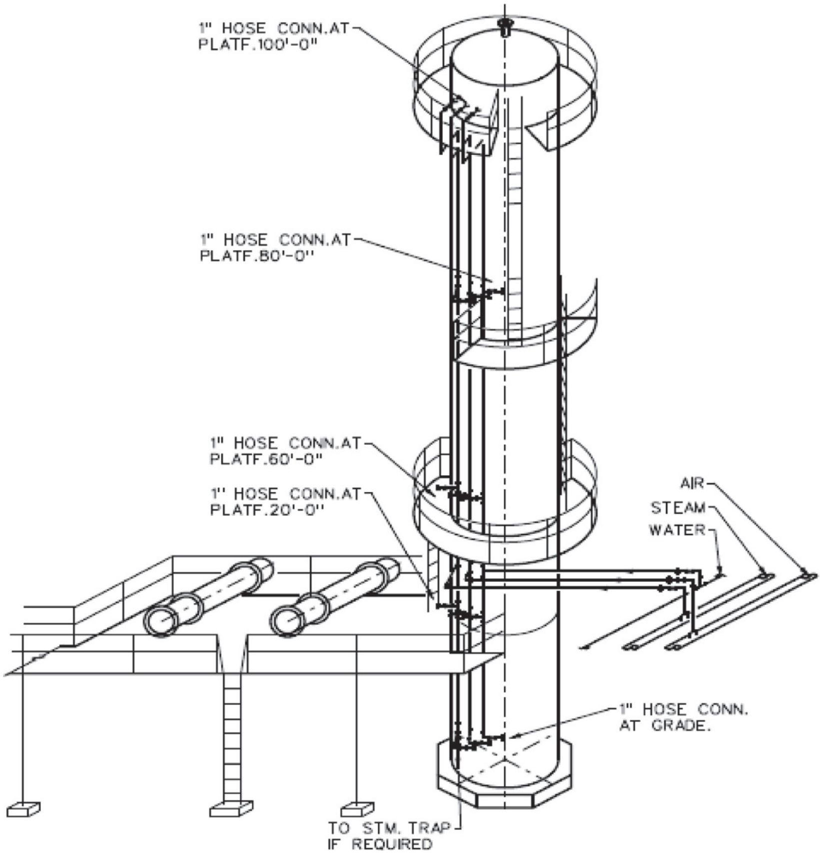
The drawing below shows piping arrangements at each platform level of tower, the designer must start at the top platform and work down the tower by laying out the correct tray orientations and then the location of the nozzles and consequently the downcomer piping.



Piping plan at tower



Top head platform piping and RV with davit



Utility stations at tower platforms

11.8 INSTRUMENTS ON TOWERS

Instruments that control the tower operation are:

- Level instruments
- Pressure instruments
- Temperature instruments

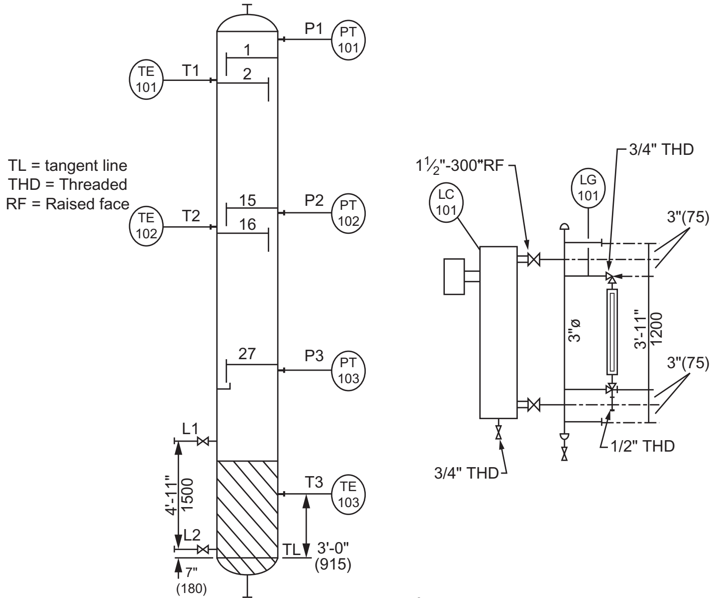
These instruments must be placed in a location that enables:

- Operation
- Maintenance
- Process function

The instruments can be located by either:

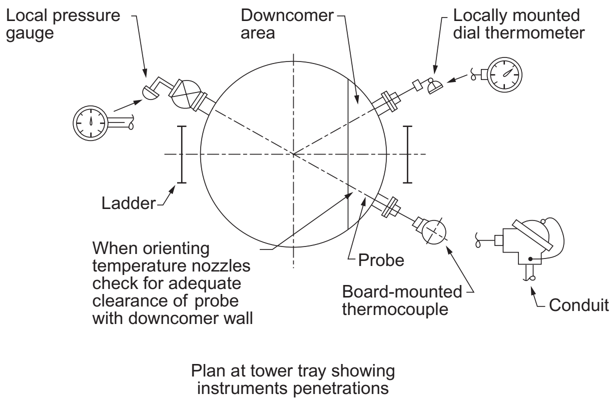
- Individually directly on the tower nozzle
- Grouped on an instrument bridle or standpipe

Instruments such as temperature and level gauges can be operated from a ladder if no platform is available at the required level

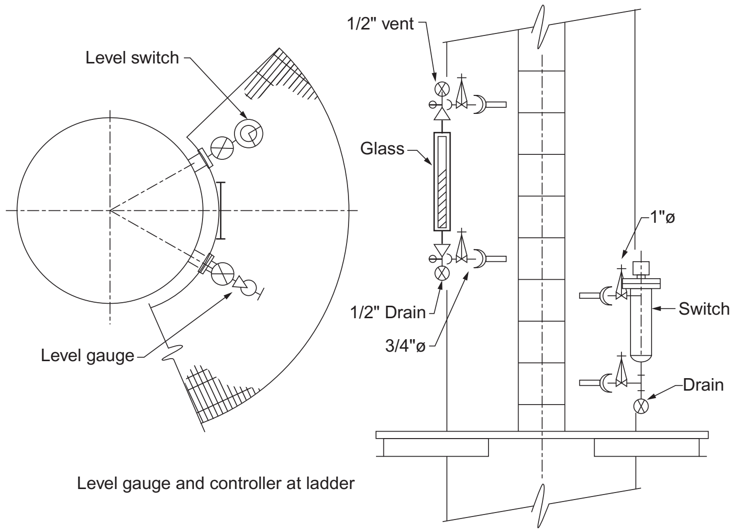


Instruments

Level Controller at Tower Nozzles



Instrument penetrations



Level gauge & controller at ladder

PLAN AT TOWER TRAY

Instruments that are located above a platform must be in an elevation from the platform of no greater than 6 ft 3 in./1.9 m in order for the maintenance and operation of isolation valves.

Instruments that are accessible from a ladder must be in a range of no greater than arms reach from the ladder, that is, 2 ft/6 m from the edge of the ladder, to enable access for maintenance and operation of isolation valves.

11.9 DESIGN OF FRACTIONATION TOWERS

Fractionation columns are designed to achieve the required separation of fluid mixtures or miscible liquids efficiently. The energy intensiveness of distillation added to the continued increase in energy costs has made it of paramount importance to develop rapid calculation procedures for the design of distillation columns. In general, the design methods for fractionation columns are similar to the design methods used for other separation processes such as absorption and extraction. This is particularly so with respect to separation efficiency since tray efficiency can be estimated more accurately than packed height equivalent to a theoretical plate the design of fractionation columns is normally made in two steps; a process design, followed by a mechanical design. The purpose of the process design is to calculate the number of required theoretical stages and stream flows including the reflux ratio, heat reflux and other heat duties. The purpose of the mechanical design, on the other hand, is to select the tower internals and calculate column diameter and height. For the efficient selection of tower internals and the accurate calculation of column height and diameter, many factors must be taken into account. Some of the factors involved in design calculations include feed load size and properties and the type of distillation column utilized. This phase of column design has a major impact on column costs, for the choice of internals influences all costs of the distillation system including the column, attendant structures, connecting piping and auxiliaries such as reboiler, condenser, feed heater, and control instruments. Fractionation columns are designed to achieve the required separation of fluid mixtures or miscible liquids efficiently. The energy intensiveness of distillation added to the continued increase in energy costs has made it of paramount importance to develop rapid calculation procedures for the design of distillation columns. In general, the design methods for fractionation columns are similar to the design methods used for other separation processes such as absorption and extraction.

CALCULATION OF COLUMN DIAMETER

In industrial applications, diameters of fractionation columns vary greatly and may range from about 65 cm in smaller towers to about 6 m and more in larger columns, even up to 15 m or 50 ft in some applications. Proper sizing of the column diameter is also crucial for other economic considerations as the costs of fractionation equipment are markedly influenced by the column diameter.

Packing is preferred for smaller towers while trays are mainly used in lager columns, with diameters greater than 3 ft or 1 m. The use of tray columns with diameters in the 1 ft, 6 in or 457 mm to 2-ft or 610 mm range is not usually economical and a packed tower in such cases will prove the best economically. On the other hand, packed towers are not limited to small units and the use of larger-diameter packing columns may still provide the less expensive choice for some specific applications.

In packed columns, some of the ultimate performance depends on the column diameter.

Rules as related to column diameter include the following four rules:

- The length to diameter ratio should be less than 30, preferably below 20, and tower height is to be limited to 60 m because of wind load and foundation concerns. If the tower is higher than 60 m, then a design with smaller tray spacing should be considered
- The ratio of tower diameter to random packing size is greater than 10.
- The tower diameter should be maintained at 1.2 m at the top for vapor disengagement.
- The tower diameter should be maintained at 2 m at the bottom for liquid level and reboiler return.

In normal practice, however, only one diameter is calculated for the whole column. Different column diameters would only be used where there is a considerable change in flow-rate. Changes in liquid rate can be allowed for by adjusting the liquid downcomer areas. If two or more diameters are calculated, say for the top and bottom sections of the column, then roughly speaking, when the difference in the calculated diameters exceeds 20%, different diameters for the top and bottom sections are likely to be economical and sections having different diameters should be at least 600 cm (20 ft) in length. Otherwise the diameter should be uniform. The preliminary column diameter would then be the larger of the two calculated diameters.

Although it is not the purpose of this book to go into how fractionation towers are designed from a process point of view, the paragraphs above outline some basic principles that govern the design of towers and are included to enhance the readers understanding of the complexity of tower design from a theoretical point of view, whereas this book mainly deals with the practical aspects of design and layout.

11.10 MAINTENANCE

Items on process towers that require maintenance are:

- Relief valves
- Control valves
- Tower trays
- Packing rings
- Internal components

Removal of these items is handled by:

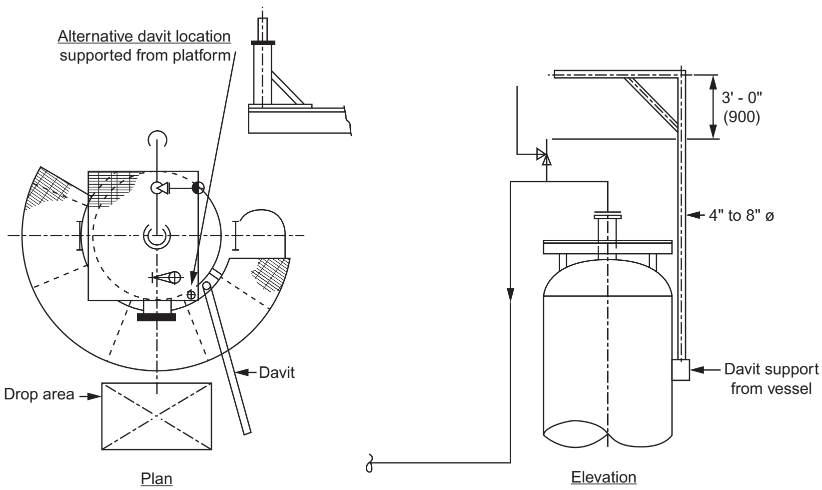
- Davits
- Trolley beams
- Crane

These items must be accessible from a platform.

The davit or trolley beam must be designed to accommodate the heaviest item to be removed.

Items are lowered down from the platform through a “Drop Area” to grade.

When mobile equipment such as a crane is used, a clear space must be provided at the back of the tower that is accessible by an auxiliary road.



Maintenance and drop zone

CHAPTER

Pipe racks/structures 12

12.1 PIPE RACKS—WIDTHS, BENT SPACING'S, AND ELEVATIONS OF RACKS

Pipe racks are the main highway in a process facility.

The **Pipe racks** connect all the equipment with piping that cannot run through the equipment areas.

Pipe racks are usually located in the middle of process plants.

If the racks are located in the middle of the plant then they have to be erected first, before becoming surrounded by process equipment.

Pipe racks support not only process piping but also utility piping, cable, and instrument trays as well as any equipment that is supported from and over the pipe rack such as air coolers.

Pipe racks require considerable planning and coordination with all disciplines to facilitate not only a logical design but also to reduce construction costs.

Data required for **pipe rack** development include

- Plot plan
- P&IDs
- Piping and plant specifications
- Construction materials
- Fireproofing requirements

Pipe rack development requires the following inputs:

- Line-routing diagram
- P&ID
- Line list
- Plot plan
- Plant layout specifications
- Client specifications
- Fireproofing requirements

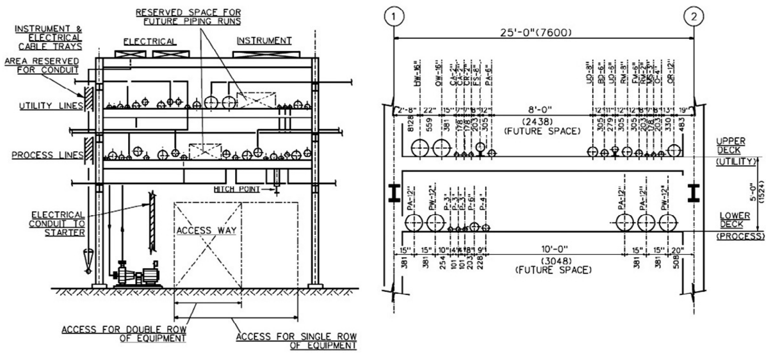
Once the number and size of lines plus a 25% allowance for future requirements and the amount of cable trays and any relief line requirements have been established, the rack size can be determined.

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00012-6

Pipe rack development requires the following inputs:

- P&IDs (process and instrument diagrams)
  - Indicates line sizes
  - Shows insulation requirements
  - Indicates equipment sequences
- Process line list
  - Shows line temperatures
  - Shows insulation requirements
  - Plus will show any other line relevant information in the remarks column
- PFDs (process flow diagrams)
  - Shows operating temperatures
  - Shows insulation requirements

On completion of the line-routing exercise, the development with regard to **pipe rack** width, bent spacing (vertical columns and horizontal structural member), numbers and levels of rack can then be finalized.



Typical section through a pipe rack

The first step in the development of any pipe rack is the generation of a **line-routing diagram**. A line-routing diagram is a schematic representation of all process piping systems drawn on a copy of pipe rack general arrangement drawing/or on the unit plot plan where the pipe rack runs in the middle of the process unit.

Based on the information available on the first issue of P&I Diagram/Process flow diagram, that is, line size, line number, pipe material, operating temperature, etc. the line-routing diagram is to be completed.

Once the routing diagram is complete, the development of rack width, structural column spacing, road crossing span, numbers of levels, and their elevations should be started.

Pipe rack column spacing shall be decided based on the economics of the pipe span as well as the truss arrangement to accommodate double the span for road crossing or avoiding underground obstructions.

Pipe rack arrangement should be developed to suit the specific plant requirements.

The pipe rack width can now be worked out with a typical cross section of the rack with the levels.

Normally, pipe racks carry process lines on the lower level or levels and the utility lines on the top level. Instrument and electrical trays are integrated on the utility level if space permits or on a separate level above all pipe levels.

Any pipe rack design should provide provision for future growth to the extent of 25%–30% on the rack clear width.

When flanges or flanged valves are required on two adjacent lines, the flanges are to be staggered.

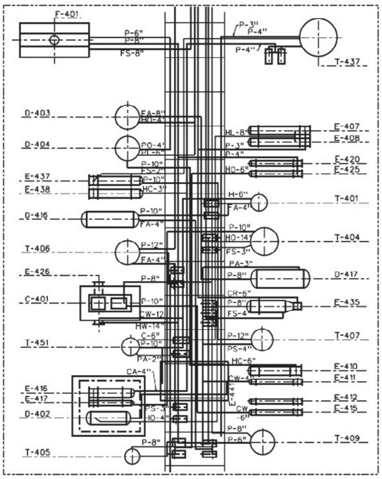
Thermal expansion or contraction must be accommodated by keeping sufficient clearance at the location where the movements will occur.

The clearance of the first line from the structural pipe rack column is to be established based on the sizes furnished by the civil/structural engineers.

After analyzing all the requirements and arrangements, the dimensions are to be rounded off to the next whole number. Based on the economics, the width and the number levels, for example, two tiers of 30-ft wide or three tiers of 20-ft wide rack will be decided.

The gap between the tiers shall be decided on the basis of the largest diameter pipeline and its branching. The difference between the bottom line of pipe in the rack and the bottom of a branch as it leaves the rack shall be decided carefully, to avoid any interference due to support, insulation, size of branch, etc. All branch lines from the main lines on pipe rack shall be taken aesthetically on a common top of steel (TOS).

With the above considerations, the conceptual arrangement of pipe rack is to be finalized.



Line Routing Diagram

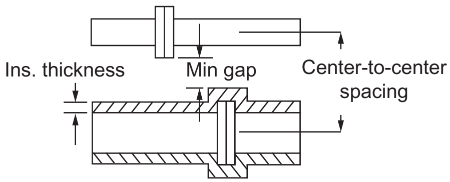
SIZE (INCHES)	SCHEDULE (INCHES)	CORROSION ALLOWANCE	VAPOR LINE INSULATION (SPAN) TO 350°	351° TO 600°F	601° TO 750°F	LIQUID LINE INSULATION (SPAN) TO 350°	351° TO 600°F	601° TO 750°F	BARE PIPE (SPAN) EMPTY (TO 350°F)	WATER FILLED (TO 350°F)	SIZE (INCHES)
3/4	40	0.05	12	11	8	12	10	7	14	13	3/4
1	40	0.05	14	13	10	14	12	9	16	14	1
1-1/2	40	0.05	18	14	14	17	15	12	19	17	1-1/2
2	40	0.10	18	16	11	17	15	11	21	18	2
2-1/2	40	0.10	23	19	16	19	18	15	25	21	2-1/2
3	40	0.10	24	21	18	21	19	16	26	22	3
4	40	0.10	27	25	22	24	23	19	29	25	4
6	40	0.10	33	31	28	29	27	25	34	29	6
8	40	0.10	39	36	33	33	32	29	40	33	8
10	40	0.10	44	42	39	37	35	34	46	38	10
12	3/8 w	0.10	47	45	42	39	38	36	49	40	12
14	3/8 w	0.10	49	47	44	40	39	37	52	41	14
16	3/8 w	0.10	53	50	47	42	41	39	55	43	16
18	3/8 w	0.10	56	54	50	44	43	40	59	45	18
20	3/8 w	0.10	59	57	53	46	45	41	62	46	20
24	3/8 w	0.10	65	62	58	48	47	43	68	49	24
3/4	80	0.10	12	10	7	11	10	6	14	13	3/4
1	80	0.10	14	12	10	13	12	9	16	14	1
1-1/2	80	0.10	17	16	14	16	15	13	10	17	1-1/2
2	80	0.10	19	17	14	18	16	13	21	19	2
2-1/2	80	0.10	22	20	18	20	19	17	23	21	2-1/2
3	80	0.10	24	22	20	22	21	19	25	23	3
4	80	0.10	27	26	23	25	24	22	29	26	4
6	80	0.10	34	32	30	31	29	28	35	31	6
8	1/2 w	0.10	39	37	35	35	33	32	40	36	8
10	1/2 w	0.10	44	42	39	38	37	35	45	39	10
12	1/2 w	0.10	47	45	43	41	40	38	49	42	12
14	1/2 w	0.10	50	48	45	42	41	40	51	44	14
16	1/2 w	0.10	53	51	49	44	43	42	55	46	16
18	1/2 w	0.10	57	55	52	47	46	44	59	48	18
20	1/2 w	0.10	59	57	55	49	47	46	62	49	20
24	1/2 w	0.10	65	63	60	52	50	49	68	52	24
1	XXS	0.25	14	13	10	13	12	10	15	14	1
1-1/2	XXS	0.25	17	16	14	16	15	14	18	17	1-1/2
2	XXS	0.25	20	18	15	18	17	15	21	19	2
2-1/2	160	0.25	21	19	17	19	18	16	23	21	2-1/2
3	160	0.25	24	22	20	22	21	19	25	23	3
4	120	0.25	27	26	23	25	24	22	29	26	4
6	80	0.25	33	31	28	28	27	26	35	29	6
8	1/2 w	0.25	38	34	33	32	30	40	34	8	8
10	1/2 w	0.25	43	41	38	36	35	33	45	37	10
12	1/2 w	0.25	47	45	41	38	37	37	49	39	12
14	1/2 w	0.25	49	47	44	39	38	37	52	40	14
16	1/2 w	0.25	52	50	48	41	40	39	55	42	16
18	1/2 w	0.25	56	53	50	43	42	40	59	47	18
20	1/2 w	0.25	59	56	53	45	44	42	62	45	20
24	1/2 w	0.25	64	60	58	47	46	45	68	48	24

Pipe Span Chart

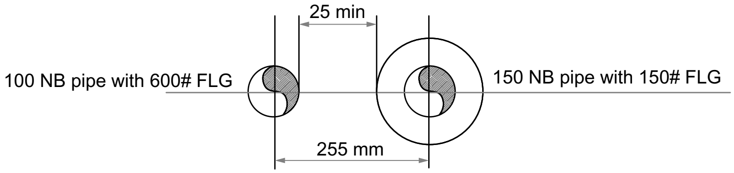
12.2 PIPE RACKS—SETTING PIPE, VALVE AND INSTRUMENT LOCATIONS

The basic principle for spacing the pipes adjacent to each other is:

Center-to-center between the pipes = half O/D (outside diameter) of the bigger size pipe flange + Insulation thickness of bigger size pipe (if applicable) + 25 mm + half O/D (outside diameter) of the smaller size pipe + Insulation thickness of smaller size pipe (if applicable).



Flange spacing



Pipe rack

PIPE ROUTING IN A PIPE RACK

All piping shall be routed so as to provide a simple, neat, and economical layout, allowing for easy support and adequate flexibility.

Piping should be arranged on horizontal racks at specific elevations. When changing direction (from longitudinal to transverse or vice versa) the piping should change elevation, but care shall be taken to avoid pockets. No piping shall be located inside instrument, electrical, or telecommunication control/switchgear rooms, except firefighting piping serving these rooms.

Rack piping shall be designed with expansion loops capable of handling relative movement of platforms in design storm conditions.

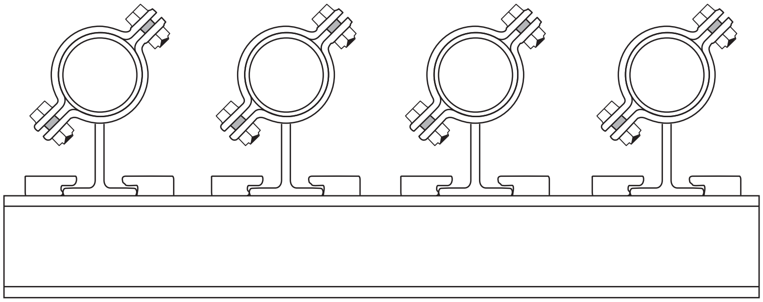
Cold and hot piping should be grouped separately with hot, noninsulated, lines at a higher elevation than cold lines. Uninsulated lines with possibility for ice build-up shall not be run above walkways.

When expansion loops are required, lines should be grouped together and located on the outside of the rack.

Small pipes should be grouped together to simplify support design.

Locating small pipes between large pipes shall be avoided especially when the large lines are hot.

To save space and for economic reasons, clamped pipe supports at an angle of 45° should be used, as shown here.



Heaviest lines should be located furthest from center of the rack.

Sloping pipes, such as flare headers and drain lines, should be located together and the routing established at an early stage in the design period to prevent difficulties which may occur if other process and utility lines are routed first.

Utility headers for water, steam, air, etc. shall be arranged on the top of multi-tiered pipe racks.

All valves requiring operation during normal or emergency conditions shall be accessible from a deck or platform.

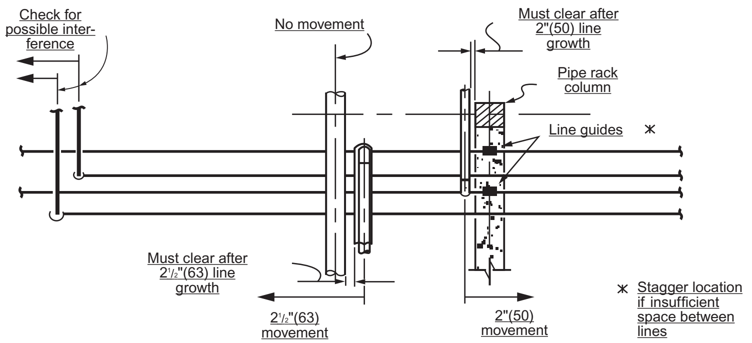
Isolation valves shall preferably be accessible from deck or platform. However, if this is not possible, valves shall be positioned such that access from temporary facilities is obtained.

Firewater ring main isolation valves shall always be accessible from deck or platform.

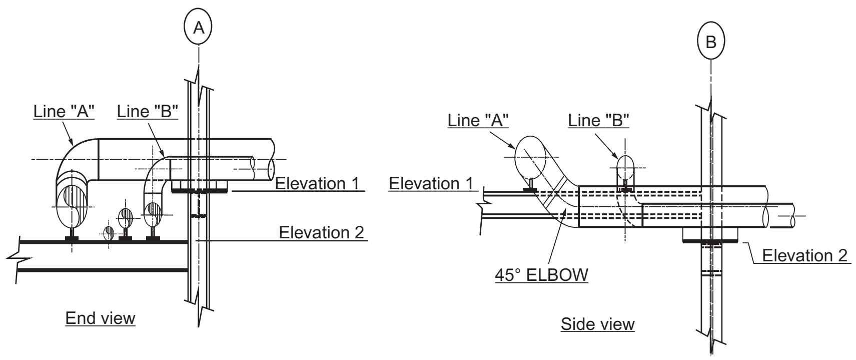
Pressure relief devices (relief valves, rupture discs) shall be accessible and installed for easy removal from deck or permanent platform. Relief valves shall be installed with the stem in the vertical position. Other valves may be tilted, as long as the stem is above horizontal position.

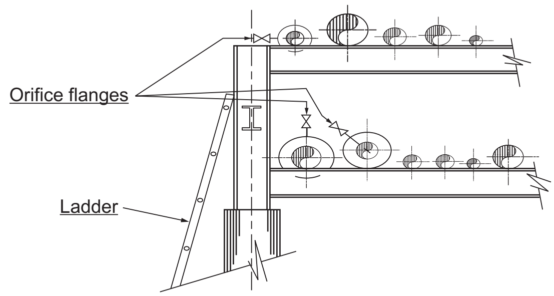
When ESD valves are installed as isolation valves, they shall be located as close as possible to the fire/blast partition.

Planning for line growth due to expansion must be taken into consideration

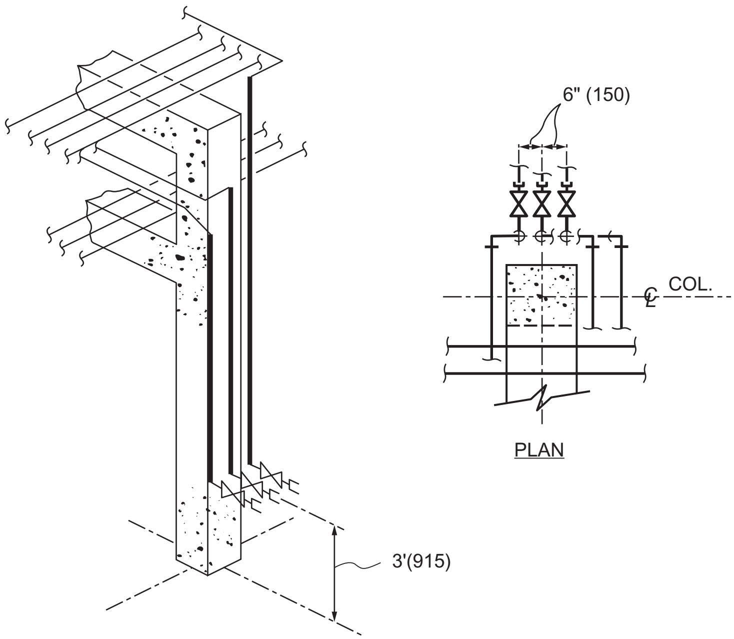


Consideration for lines leaving and entering a rack

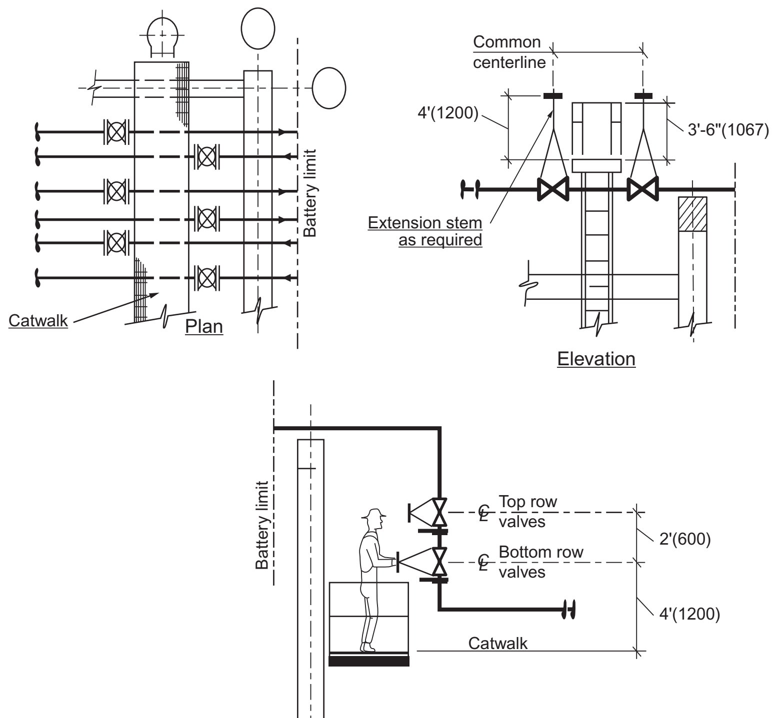




Part section through pipe rack



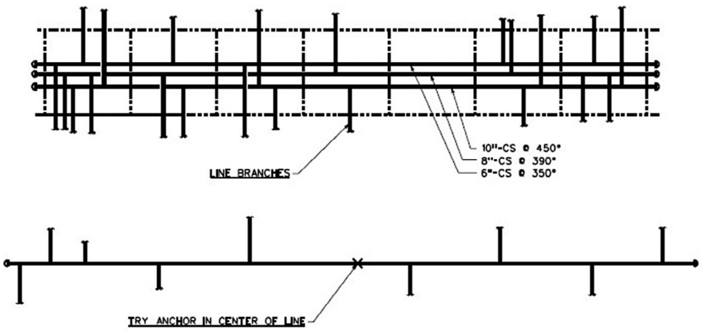
Location of utility lines at pipe rack column



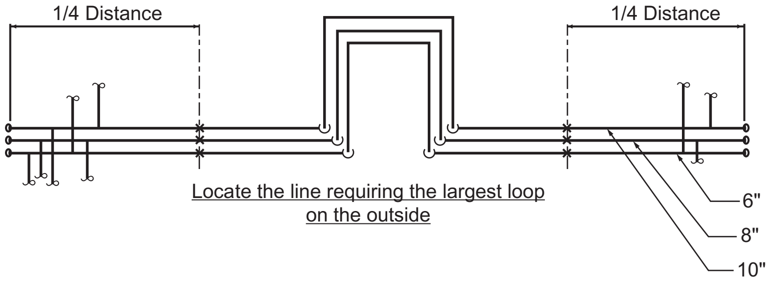
Battery limit valves

12.3 PIPE RACKS—PIPING FLEXIBILITY AND SUPPORTS

Hot lines on pipe racks need to be checked for flexibility; therefore, the hot lines must be identified.



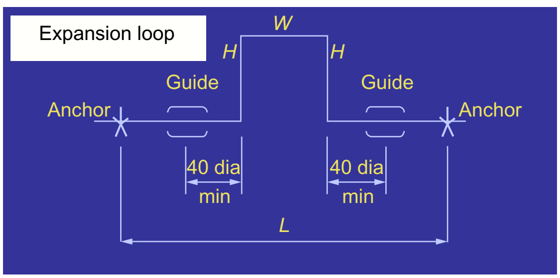
Determine if one anchor (central) anchor point will suffice. If a single anchor will not work two anchors with an expansion loop must be used, as shown below.



There are quick check formulas that can be used to size the loops for the planning phase; these can then be checked by the stress engineer. These quick check formulas are dealt with in detail in Chapter 19 of this book.

PIPE RACKS—PIPING FLEXIBILITY AND SUPPORTS

Formulas for Expansion Loops:



For example:

$$\begin{aligned}&\text{Pipe} = 12'' \text{ STD wt.}\\&\text{Do} = 12.75 \text{ so use } 13''\\&T = 520 - 70 = 450^\circ\text{F}/271 - 21^\circ\text{C}\\&L = 200' - 0''/61\,\text{m}\end{aligned}$$

$$\text{minimum } h = 0.02\sqrt{\text{Do} \times L \times T}$$

$$\text{Minimum } h^2 = 0.0004 \times \text{Do} \times L \times T$$

$$\text{Maximum } L = \frac{2500(h^2)}{\text{Do} \times T}$$

$$\text{Minimum } W = 0.5h$$

$$\text{Preferred } W = 1.5h$$

$$\text{To test for minimum } h : h = \frac{A \times \text{Do}}{1.25}$$

Coefficients for Carbon Steel—A Design Temp					
°F	**°C**	A	**°F**	**°C**	A
150	65	0.4	700	371	2.5
200	93	0.6	800	427	2.8
300	149	1	900	482	2.95
400	204	1.4	1000	538	3.15
500	260	1.8			
600	315	2.2			

To solve for minimum h: (imperial measure)

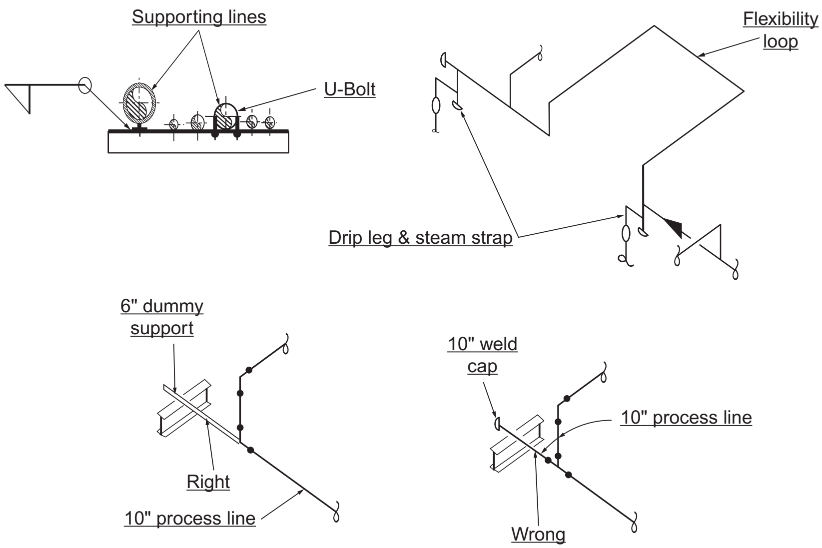
$$h^2 = 0.0004 \times 13 \times 200 \times 450$$
$$h = \sqrt{468}$$
$$= 21.6'$$

$$\text{Minimum } W = 0.5 \times 21.6$$
$$= 10.8'$$

$$\text{To test for minimum } h = \frac{1.88 \times 13}{1.25}$$
$$= 19.5$$

Therefore: use the larger $21.6'$

PIPE RACKS—PIPING FLEXIBILITY AND SUPPORTS



12.4 PIPE RACKS—STRUCTURAL CONSIDERATIONS

The engineer must be aware of any structural considerations:

Bracing at columns—adequate space must be allowed for lines entering and exiting the rack close to columns. Therefore, it is always best to allow a 600 mm^2 ft dead space either side of the column to allow for bracing, and not to run piping in this area by the column.

Preconcrete pipe racks have members that are larger than steel designs, so this must be taken into consideration.

Installation sequence must be taken into consideration.

Anchor bays will have extra cross bracing for stability.

When equipment is supported over a rack such as air coolers and drums, the supporting members will be larger.

When hydrocarbons are present fireproofing of the columns, usually to a level just below the lower rack support beam.

If other equipment such as air coolers is located above the pipe rack then the fireproofing must be extended up to the equipment support beam.

Primary to secondary rack elevations must be designed to accept the largest pipe, and instrument trays must be allowed for.

Rack intersections must be staggered by one bay, if more than one rack intercepts the primary rack at the same location.

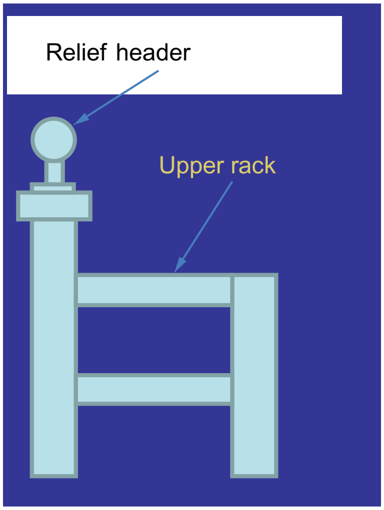
12.5 PIPE RACKS—OTHER CONSIDERATIONS

Each change of rack direction requires a change in rack elevation.

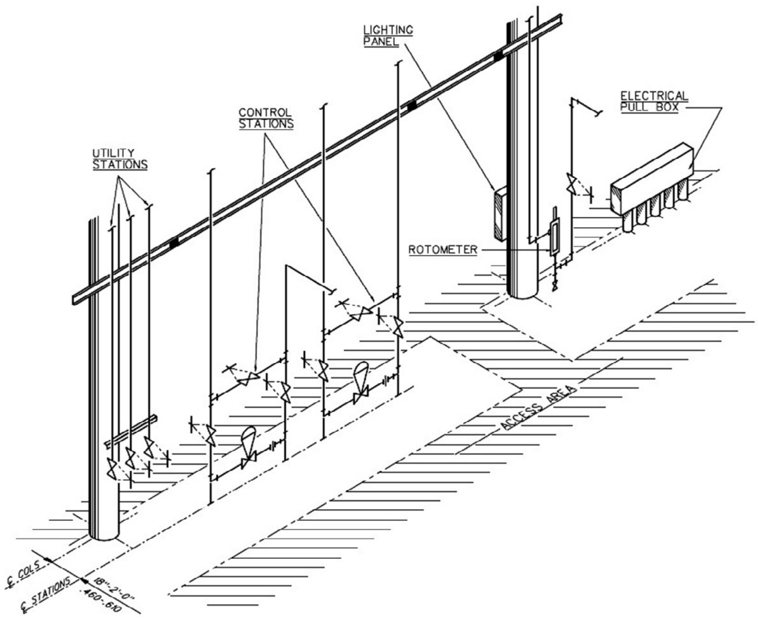
Where flat turn pipe racks are used (more often than not these are located near a dead end area, or at the end of the rack system), the line sequences cannot change at the change of direction as it can in racks of different elevations.

The pipe rack beams must be large enough to allow for 25% future expansion for the addition of piping and instrument/cables trays.

Relief headers are usually located by extending the pipe rack column above the upper horizontal support beam, to the required elevation to allow for relief header slope to a knock out drum.



Pipe rack elevation showing location of relief (flare) header



Utility stations & control valve stations at pipe rack

12.6 STRUCTURES—DESIGN FEATURES

Structures are found in most process facilities:

They are used to:

- Accommodate equipment
- To meet process requirements
- To meet NPSH requirements
- Economize on real estate

Design considerations:

The following are a list of considerations that must be taken into account when designing a structure:

- Will it need to be an open or closed structure?
- Materials of construction will steel or concrete be used
- What will be the roof and siding requirements is partial cladding required due to climate conditions
- What type of frame will be used will it be a rigid frame or a braced frame
- What type of flooring will be used, does the floor need to contain spillage or can it be open grating
- What are the fireproofing requirements?
- Equipment maintenance—equipment needs enough space around, above and below to be able to provide adequate maintenance of the equipment
- Access—adequate egress around equipment and escape routes to and from the structure must be accounted for
- Adequate stairways and ladders must be provided in accordance with OSHA standards
- Handrails must be provided around all elevated platforms
- Monorails, davits, and hitch points must be located to facilitate the removal and maintenance of heavy equipment
- Elevators must be included if required to transport items such as sacks of catalyst, personnel and pallet trucks, etc., to upper level platform's

Design features:

When designing the structure, the following must also be allowed for:

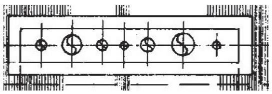
- Piping loads
- Earthquake loads
- Wind loads
- Equipment loads
- Exchanger bundle removal loads (half weight of tube bundle)
- Thermal expansion loads
- Pipe anchor loads

- Dynamic loadings (response of equipment and structure to cyclical loadings produced by rotating and reciprocating equipment, for example, pumps and compressors)

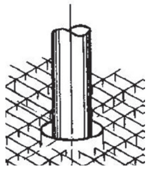
Flooring:

Flooring is dependent on the type of structure
Concrete structure will have concrete flooring
Steel structure will have steel flooring of either chequer plate or open grating

For piping passing through (penetrating) either a concrete or steel floor a "Pipe Chase" must be used

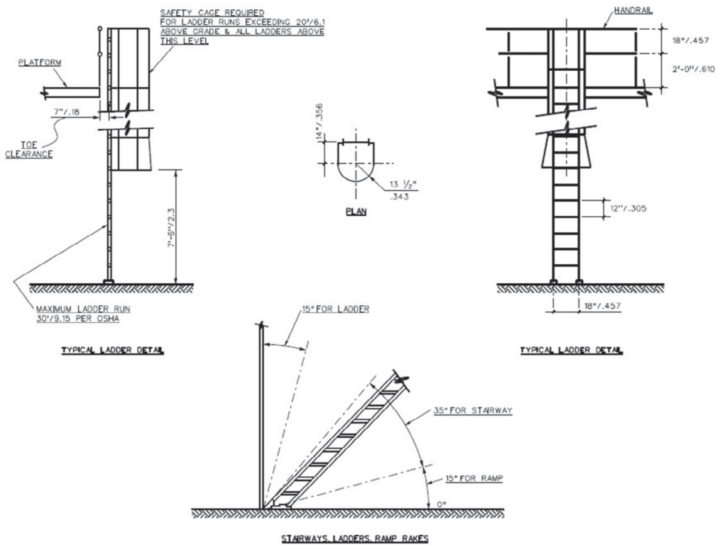


Plan View of Pipe Chase



Elevation showing pipe chase through Platform grating

Ladders

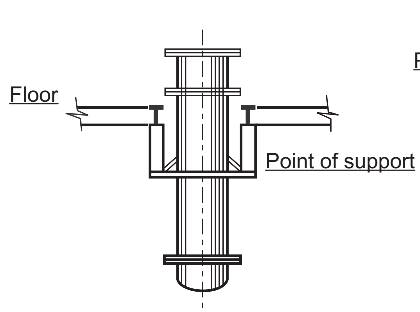


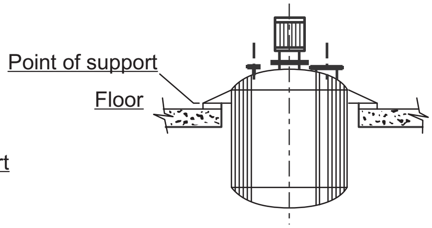
All stairways, ladders, ramps, and handrails must meet OSHA requirements.

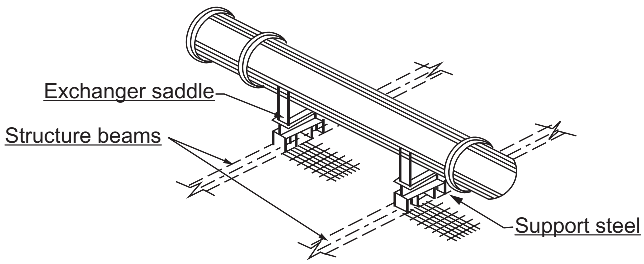
All dead-end platforms that are 50-ft/15-m long or more must have an escape ladder at the opposite end of the platform to the stairway.

12.7 STRUCTURES—STRUCTURAL DETAILS

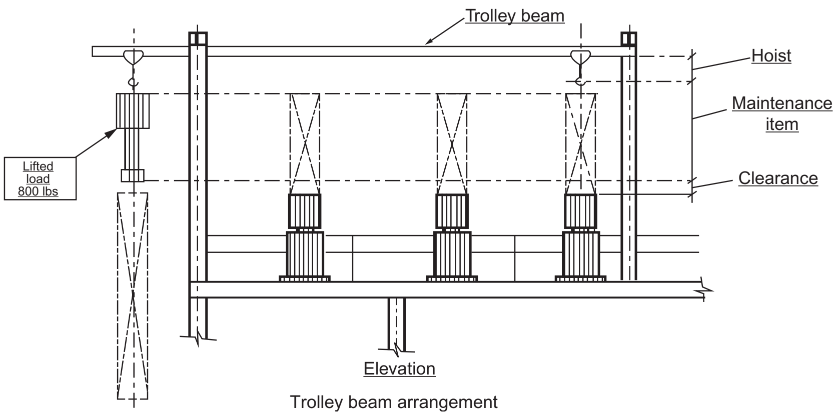
Equipment Support @ Vertical Exchanger Equipment Support @ Vertical Reactor







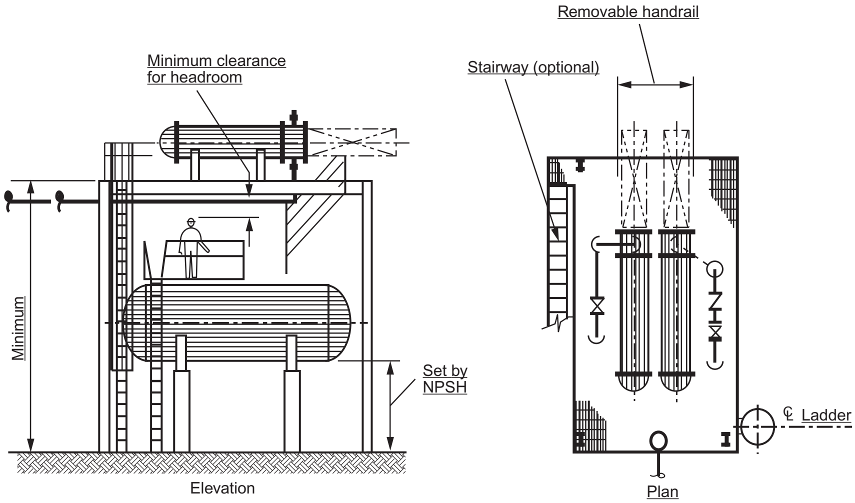
Equipment support @ Horizontal exchanger



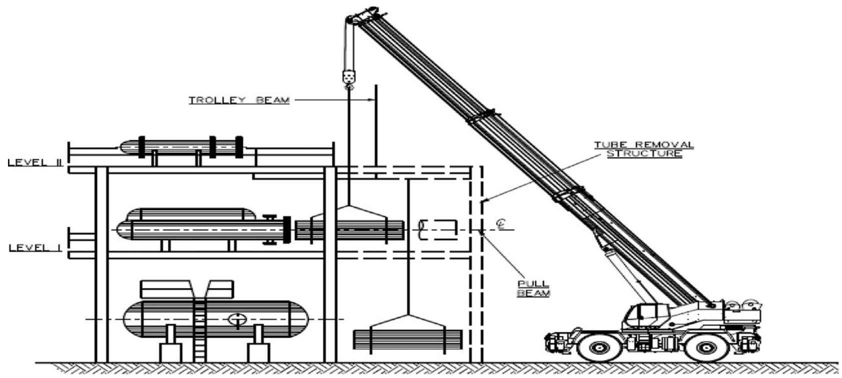
Elevation

Trolley beam arrangement

12.8 STRUCTURAL ARRANGEMENTS

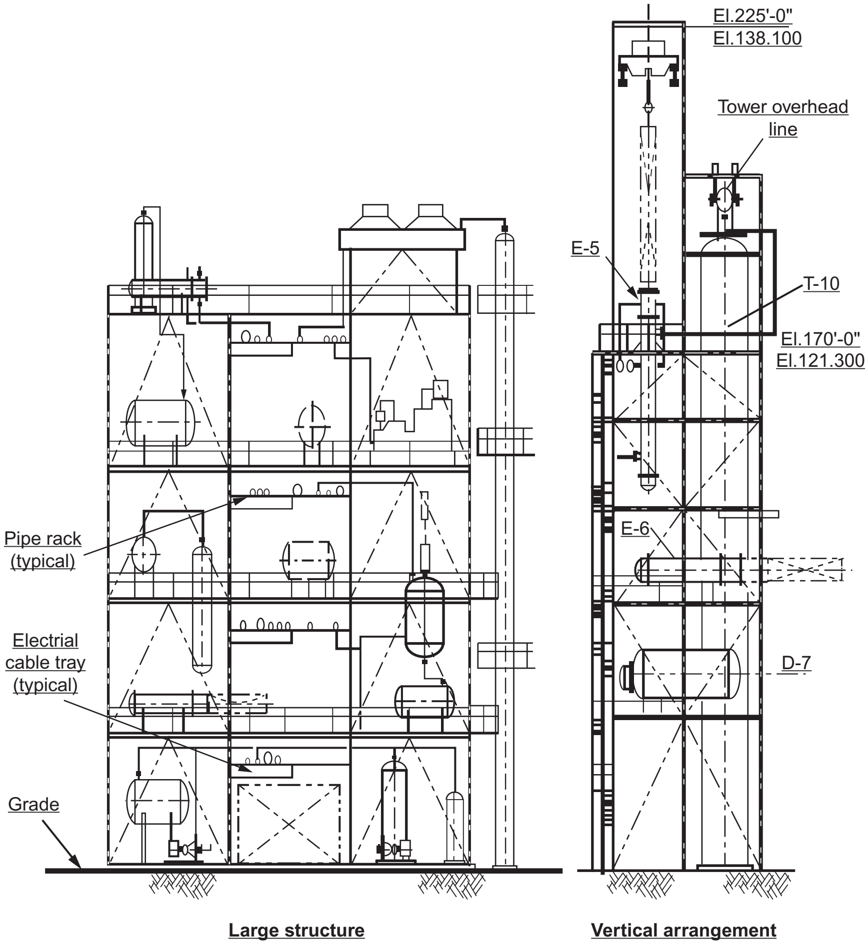


Single level — single bay structure

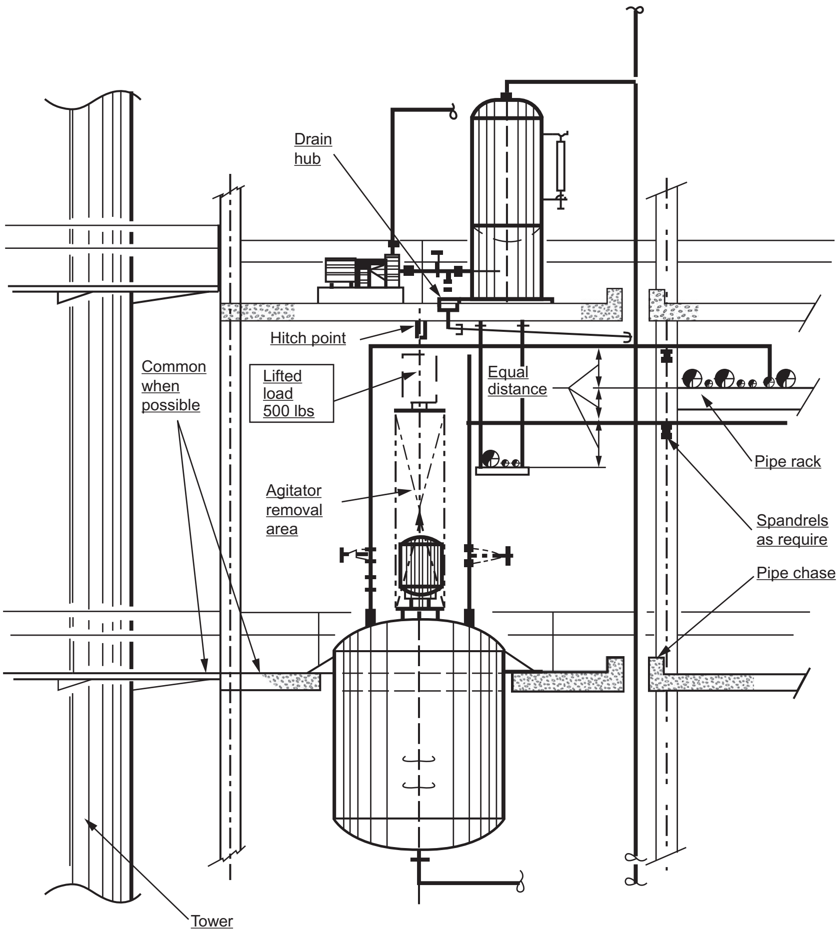


Two Level Small Structures

MULTILEVEL STRUCTURES



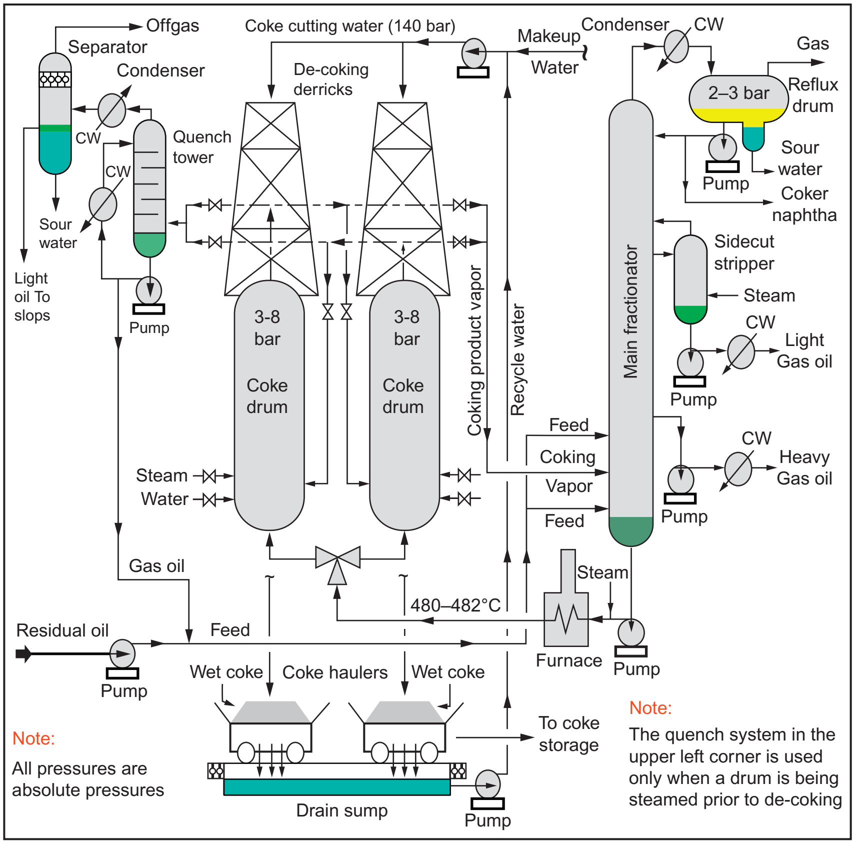
Multilevel structures



Typical cross section through structure showing piping around a reactor

12.9 STRUCTURES—DRILL STRUCTURES—COKER UNITS

Photo of a coker unit drill structure



Coker unit schematic

12.10 STRUCTURES—OPERATIONS PLATFORMS

All structures whether small, medium, or large need operating platforms for access to valves, equipment, piping, operations, and maintenance.

Platforms must be big enough to allow for equipment access, operations, and adequate safety egress.

Each level of platform must be furnished with stair access and safety egress including emergency escape ladders in the case of large platforms.

Top head platforms on structures are required for catalyst loading and will require monorails with access to grade.

Allowances must be made on each platform level for maintenance and equipment removal such as tube bundle extraction.

Adequate access around equipment for operations and egress must be allowed for.

Adequate headroom between floor levels must be accounted for, to allow for pipe supporting, beam depths and monorail clearances, cable and electrical trays

All egress ways on platforms must be clear of any obstructions such as hose stations, electrical boxes, and control panels.

Any dead end platform of 50 ft/15 m or longer between exit points must be furnished with emergency escape ladders at the opposite end of the platform, in addition to the primary stair.

CHAPTER

Underground piping 13

13.1 INDUSTRY STANDARDS

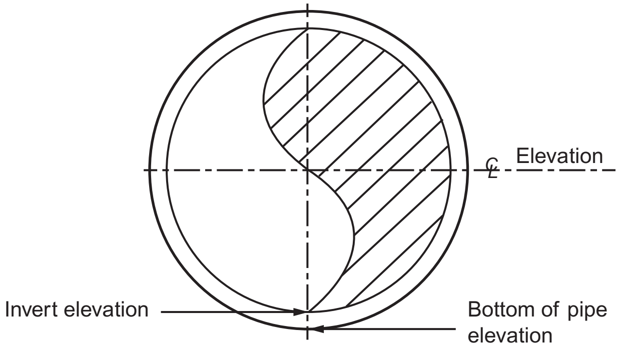
The following list shows ASTM, DIN, and SAS standards with regard to underground pipework.

- ASTM A74—cast Iron soil pipe and fittings
- ASTM A120—steel, black and hot dipped, zinc-coated (Galvanized) welded, and seamless pipe
- ASTM A746—ductile iron gravity sewer pipe
- ASTM C425—compression joints for vitrified clay pipe and fittings
- ASTM C700—vitrified clay pipe
- ASTM D1785—polyvinyl chloride (PVC) plastic pipe
- ASTM D3034—type PSM PVC sewer pipe and fittings
- DIN 1230—clayware for sewer systems
- SAS 14—pipes unplasticized plastic (PVC) for potable water
- SAS 236—clay pipes for sewer and water drainage

13.2 TERMINOLOGY

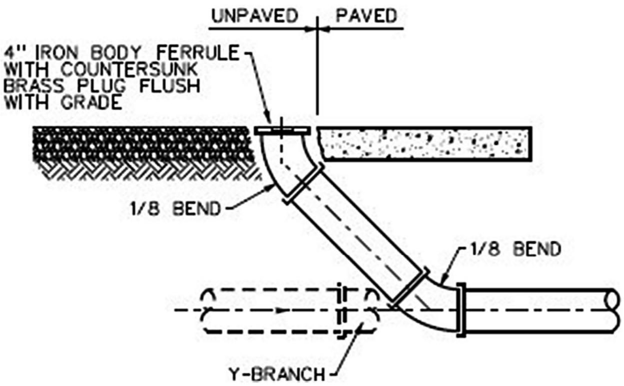
Listed below are some of the more common terms used in relation to underground pipework:

- **Invert elevation**—inside bottom of the pipe



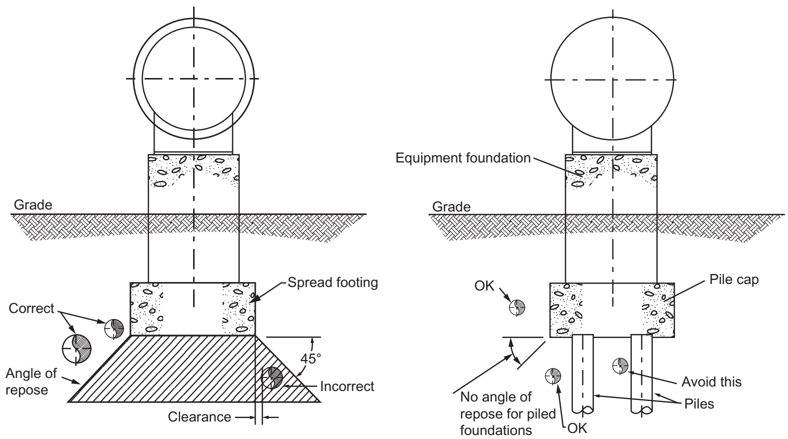
The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00013-8

- **Main** (sewer main)—primary drain line (separated into sections between sewer boxes)
- **Sewer box**—(used in oily water systems) box that separates primary drain lines for safety reasons
- **Branch**—collection subheader that collects from catch basins and drain hubs, and is tied into a sublateral
- **Lateral—**drain line which collects from two or more sublaterals
- **Sub Lateral—**collect branch lines and sealed sewer boxes into a lateral



- **Cleanout**—piping connection (usually Y-connection) located at grade to enable inspection and cleaning
- **Catch basin—**device that collects surface drainage, and has an outlet liquid seal and sediment trap
- **Seal—**device that isolates potential spread of fire between areas in a sewer system

Angle of repose—this is the angle under a foundation (piping cannot be placed here)



13.3 TYPES OF SYSTEMS

UNDERGROUND DRAINAGE SYSTEMS

These consist of:

- Contaminated stormwater
- Uncontaminated stormwater
- Chemical sewers
- Oily Water service
- Combined sewers
- Sanitary sewers
- Blowdown systems
- Pump-out systems
- Solvent collection systems

CONTAMINATED STORMWATER

This must be collected and treated; surface drainage from areas containing hydrocarbon equipment. The stormwater from these drains must pass through a treatment facility before being discharged into an uncontaminated system such as a river stream or body of water.

UNCONTAMINATED STORMWATER

This must be collected from process areas, access, and roadways. These surface area drains are used along with catch basins and ditches. This water must be free of any hydrocarbons, if not the drainage must be diverted to a contaminated stormwater drain. The system must be sized to allow for not only rainwater but firewater as well.

CONTAMINATED STORMWATER

This must be collected from areas containing hydrocarbon-bearing equipment. The contaminated water must pass through a treatment facility before being discharged into uncontaminated areas such as rivers, streams or offshore.

CHEMICAL SEWERS

Recover chemicals and acids from equipment, piping, and surface drainage. These areas use curbs to contain any liquids. The liquids are routed to either a sump or a neutralization facility for disposal and discharge into an oily water system.

OILY WATER SEWERS

This collects waste, leaks, and any drips from equipment and piping in process areas (noncorrosive services). Piping engineer must identify any equipment and piping that will require a drain, and provide a curbed area around the equipment or piping and also provide a drain hub.

SANITARY SEWERS

Collect raw waste from lavatories, these can be discharged to unit limit or lift station for disposal and routed to a septic tank or leeching field.

PUMP-OUT SYSTEMS

For pump-out systems you need to avoid pockets. Trenches are generally used for these systems and if piped systems are used and the line is hot, which allow for expansion.

BLOWDOWN SYSTEMS

These collect drains from steam drums and boilers. This system is run as a separate system usually to the battery limit. It can be tied into an oily water sewer, provided it is located downstream of any sewer box that might collect drainage from a furnace. The furnace sewer box has an airtight cover and atmospheric vents, and is located at a minimum distance of 50 ft/15 m from the fired heater.

SOLVENT COLLECTION SYSTEMS

Solvents are used to remove CO_2 from gas streams. The solvents have to be reclaimed by using a separate drainage system (as indicated on the P&IDs). The piping on these collection systems will run to an underground sump from where it will be pumped out.

UNDERGROUND PIPING AND SERVICES

These consist of:

- Combined sewers
- Underground cooling water
- Firewater
- Potable water
- Cable and instrument banks

COMBINED SEWERS

This type of sewer carries both oily water and stormwater, which can be tied into a common system.

UNDERGROUND COOLING WATER

Piping in the form of an underground header system is routed underground to process equipment such as heat exchangers, surface condensers, and pumps. This piping can also be run above ground on pipe racks depending on the particular philosophy of the facility being built.

FIREWATER

Underground piping loops are the most common used around the process units or equipment. These loops have branches for hydrants and monitors for fire protection.

POTABLE WATER

Used for drinking, emergency eye washes, shower facilities, washrooms, and office facilities

TYPES OF SYSTEMS

When designing an underground piping system, the following information is required:

- Piping specifications
- Underground specifications
- Client specifications
- Plot plan
- Type of system to be used (e.g., oily water, stormwater)
- Equipment arrangement drawing
- Piping studies
- Local and national codes and regulations
- Site obstructions
- Topographic information
- Site data
- Maximum rainfall
- Frost depth
- Electrical and instrument conduit routings (if underground)
- Firewater requirements
- Invert elevations of lines at the process battery limit
- Paving, pipe trenches, foundation sizes, and road limits

13.4 CONSTRUCTION MATERIALS

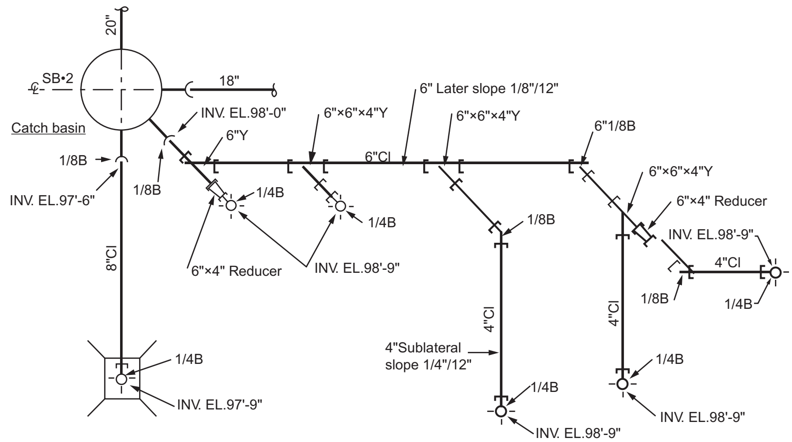
The following construction materials and their uses that are used in the fabrication of underground pipe are listed below:

Carbon steel—closed-drain systems, cooling water, and firewater
Stainless steel—closed drains—chemical and corrosive service
Cast iron—stormwater and oily water drains (hub and spigot fittings)
Ductile iron—Process water (stress value is higher than cast iron) (hub and spigot fittings)
Concrete pipe—surface drainage, and for 15″ and larger pipes
Fiberglass reinforced plastic pipe—corrosive service, low-temperature and -pressure systems
PVC—corrosive service
Vitrified clay pipe—gravity drain systems cannot be used under roads or when subjected to significant loads (maximum operating temperature 200°F/93°C)
Glass Pipe—floor drains in process plants, mainly acid service

13.5 OILY WATER AND STORMWATER SYSTEMS

By using the preliminary plot plan, the engineer can start identifying locations of:

- Oily water drains
- Stormwater mains
- Sewer boxes
- Invert level of the piping system at both ends of the unit

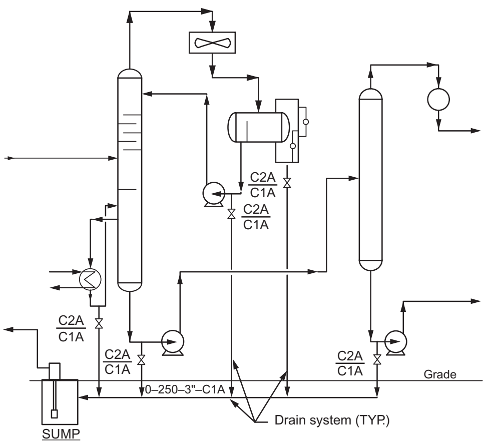


Drawing showing catch basin and underground piping laterals and hubs

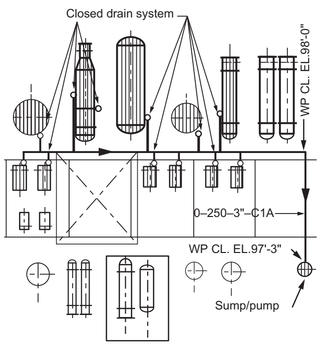
13.6 CHEMICAL AND PROCESS CLOSED SEWERS

These are designed to collect:

- Corrosive waste
- Toxic chemical waste
- Surface drainage

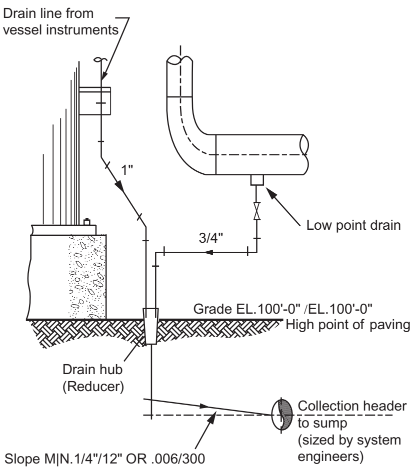


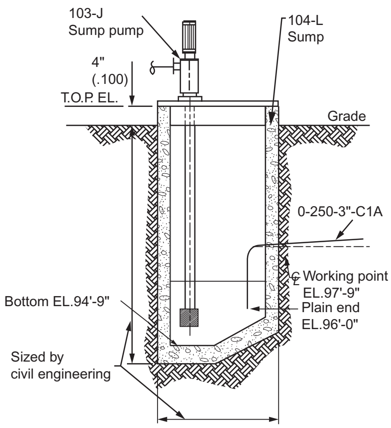
PFD showing closed drain system



Piping plan of closed drain system

CHEMICAL AND PROCESS CLOSED SEWERS

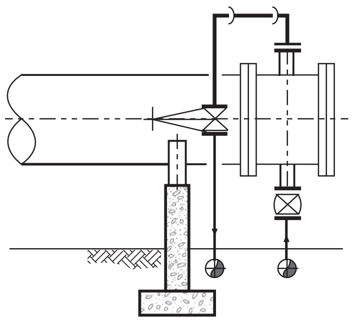




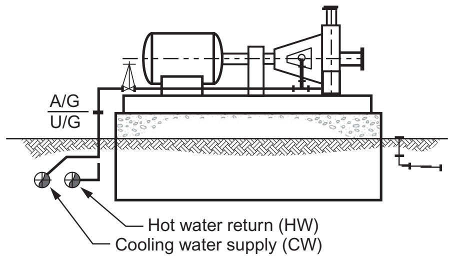
13.7 PROCESS AND POTABLE WATER

Process water is used for:

Cooling water—for temperature control of the process streams in exchangers
Cooling water—for seals in pumps and compressors
Condensing steam—exhaust in surface condensers in low-pressure steam systems



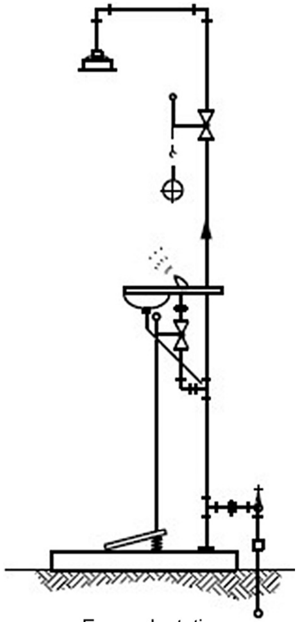
Cooling water @ exchanger tube end



Cooling water to pump seals

Potable water is used for:

- Drinking water
- Emergency eyewashes
- Shower installations

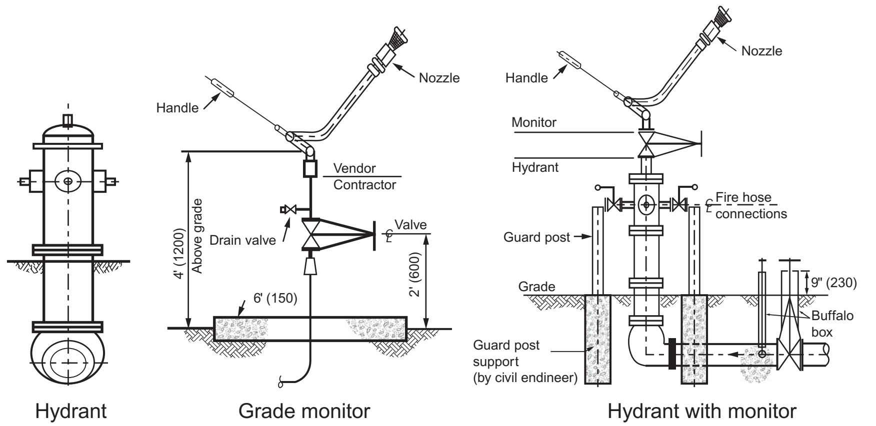


Eyewash station

13.8 FIREWATER SYSTEMS

Firewater systems comprise of the following equipment:

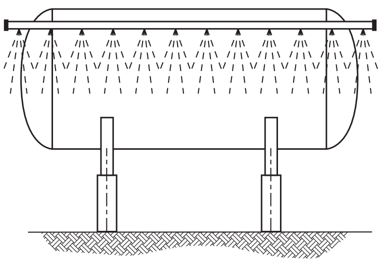
- Hydrants
- Monitors
- Deluge spray systems
- Hose reels
- Firewater ring main



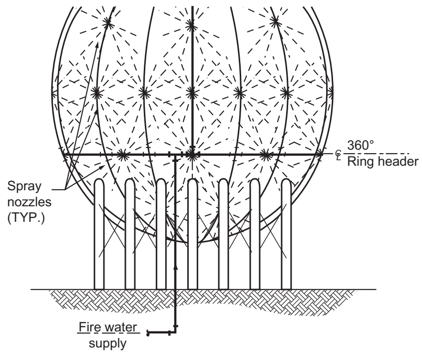
Each item of equipment must be protected by a hydrant and a monitor. Deluge spray systems can also be added for further protection based on client and NFPA specifications. Studies must be completed by engineers for compliance to the relevant codes. All firewater shut off valves must be located at a minimum of 50 ft/15 m from any potential fire source.

DELUGE SYSTEMS

Deluge and spray systems are generally used when a fire monitor spray cannot reach a piece of process equipment. Deluge systems can also be used in addition to fire monitors for added protection or as client specifications dictate. A typical spray system consists of a series of ring headers around the equipment to be protected with spray nozzles at intervals around the header, angled down or up to provide a constant spray over the effected hot metal area during a fire.



Horizontal tank showing deluge sprays



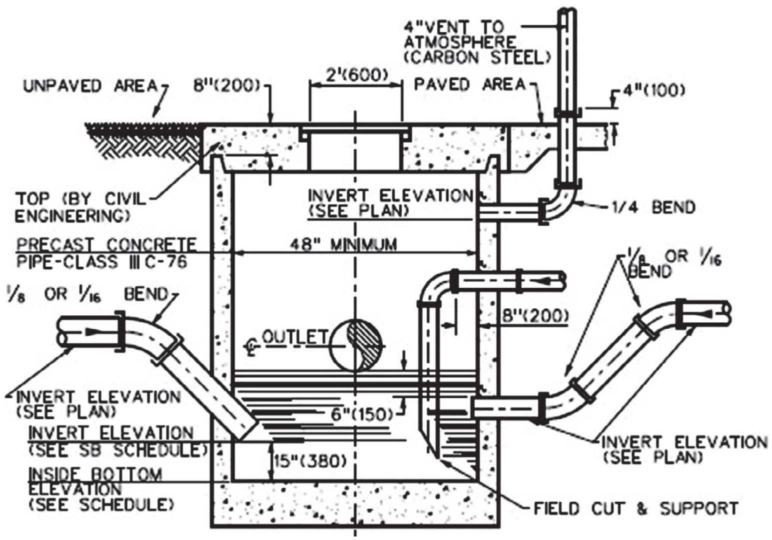
Sphere showing deluge sprays

13.9 UNDERGROUND ELECTRICAL AND INSTRUMENT DUCTS

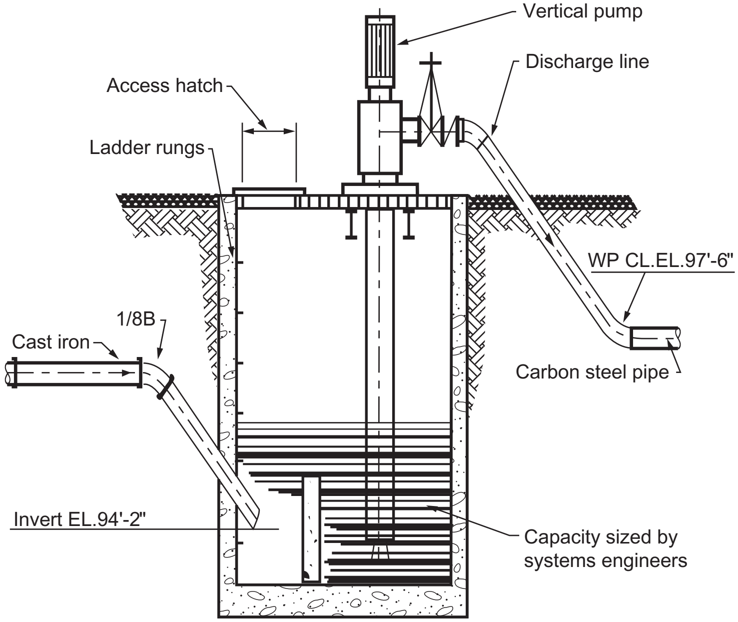
If electrical and instrument ducts are to be run underground, this will be usually determined at the beginning of a project. Even if above ground is determined, there might be some instances where below ground needs to be considered as well. It is usually more cost effective and easier to run these dusts above ground. If the need to run below ground is determined then the following must be taken into consideration:

- Terrain, frost Level, and equipment foundation
- Grade slabs, drainage, and piping structural foundations
- Building shelters, roadways, pipe racks, control rooms, and trenches

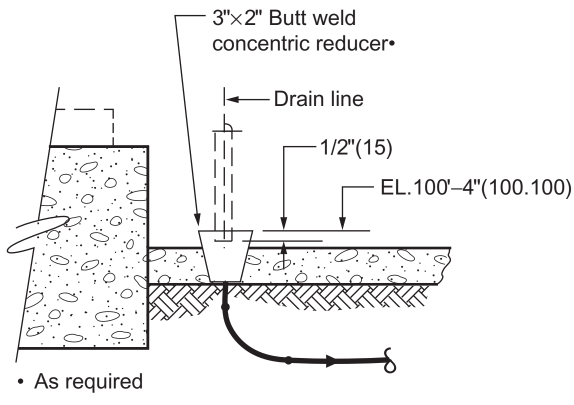
13.10 UNDERGROUND DETAILS



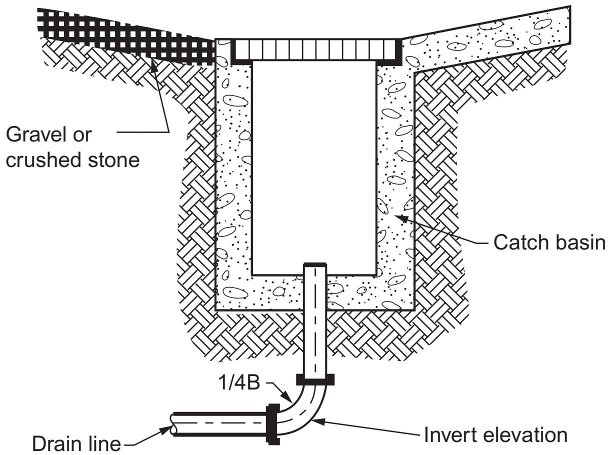
Sewer box



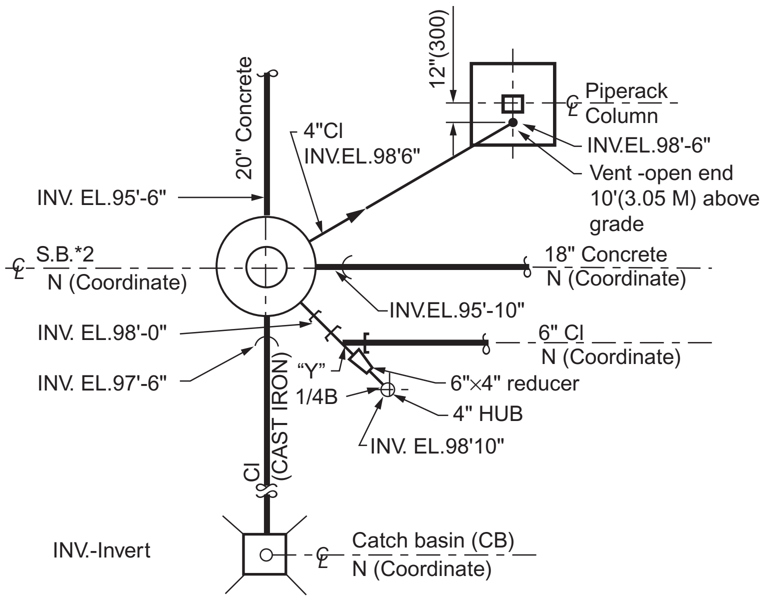
Lift station



Chemical drain



Catch basin



Sewer box detail

13.11 LINE SIZING

Lines are sized for oily water and storm sewers to handle rainfall plus process water drainage, whichever is greater. Rainfall rates are determined by the project data. Process water rates are determined by process engineers. Firewater and deluge system quantities must also be taken into consideration. Local rainfall charts should be consulted before line sizes are calculated. Firewater flow rates for a process area is usually set at around 1000 gpm/3780 lpm. Maximum firewater should not exceed 2000 gpm/7560 lpm coefficients used for surface drainage.

- Rainwater—paved area = 90% (0.9)
- Rainwater—unpaved area = 50% (0.5)
- Firewater—all areas = 100% (1.0)

Run-off rates are calculated by the following formula:

Q = KICA
Q = run off rate in gpm/lpm
K = conversion constant (0.01039 for flow in gpm)
I = rainfall intensity in inches/mm per hour

C = run off coefficient
A = area of surface to be drained in sq ft/sq m

Gravity flow rates for sewer lines should be between 3 and 5 ft per second/0.9 and 3.24 m per second.

LINE SIZING: CALCULATIONS USING THE "MANNING FORMULA"

The velocity of flow in a pipe can be found using the **Manning formula,** which is also known as the Gauckler-Manning formula, or Gauckler-Manning-Strickler formula in Europe. In the United States, in practice, it is very frequently called simply **Manning's Equation**. The **Manning formula** is an empirical formula estimating the average velocity of a liquid flowing in a conduit that does not completely enclose the liquid, that is, open channel flow. All flow in the so-called open channels is driven by gravity. It was first presented by the French engineer Philippe Gauckler in 1867, and later redeveloped by the Irish engineer Robert Manning in 1890.

The Gauckler-Manning formula states:

$$V = \frac{k}{n} {R_h}^{2/3} S^{1/2}$$

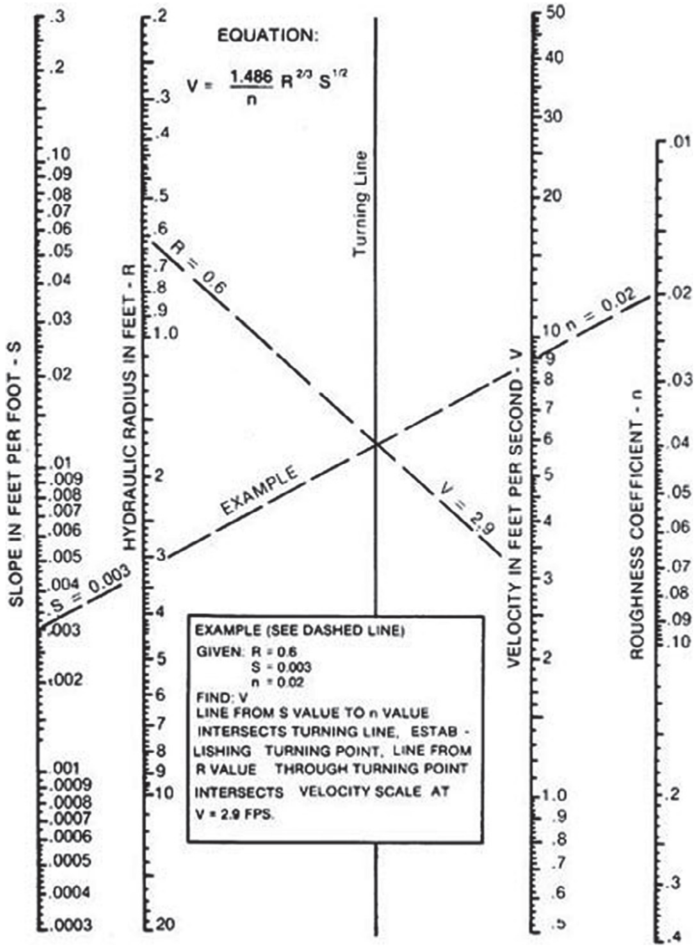
where:

- V is the cross-sectional average velocity (L/T; ft./s, m/s);
- n is the Gauckler-Manning coefficient. Units for values of n are often left off, however it is not dimensionless, having units of: (T/[$L^{1/3}$]; s/[$ft^{1/3}$]; s/[$m^{1/3}$]).
- R_h is the hydraulic radius (L; ft, m);
- S is the slope of the hydraulic grade line or the linear hydraulic head loss (L/L), which is the same as the channel bed slope when the water depth is constant ($S = h_f/L$).
- k is a conversion factor between SI and English units. It can be left off, as long as you make sure to note and correct the units in your "n" term. If you leave "n" in the traditional SI units, k is just the dimensional analysis to convert to English. $k = 1$ for SI units, and $k = 1.49$ for English units. (Note: $(1\ \text{m})^{1/3}/\text{s} = (3.2808399\ \text{ft})^{1/3}/\text{s} = 1.4859\ \text{ft}^{1/3}/\text{s}$.)

Note: Ks strickler $= 1/n$ manning. The coefficient Ks strickler varies from 20 (rough stone and rough surface) to 80 $m^{1/3}$/s (smooth concrete and cast iron).

The discharge formula, $Q = A\ V$, can be used to manipulate Gauckler-Manning's equation by substitution for V. Solving for Q then allows an estimate of the volumetric flow rate (discharge) without knowing the limiting or actual flow velocity.

The Gauckler-Manning formula is used to estimate the average velocity of water flowing in an open channel in locations where it is not practical to construct a weir or flume to measure flow with greater accuracy. The friction coefficients across weirs and orifices are less subjective than n along a natural (earthen, stone, or vegetated) channel reach. Cross-sectional area, as well as n', will likely vary along a natural channel. Accordingly, more error is expected in estimating the average velocity by assuming a Manning's *n*, than by direct sampling (i.e., with a current flowmeter), or measuring it across weirs, flumes, or orifices. Manning's equation is also commonly used as part of a numerical step method, such as the Standard Step Method, for delineating the free surface profile of water flowing in an open channel



Nomograph for calculation of velocity

CHAPTER

Instrumentation

14

14.1 TYPES OF INSTRUMENTS

Instruments used in process facilities consist of:

LEVEL INSTRUMENTS

Level instruments can be any of the following:

- Level gauges
- Level transmitter
- Radar, ultrasonic, and DP cells

PRESSURE INSTRUMENTS

Pressure instruments can either be:

- Pressure gauges
- Pressure transmitters
- DP cells

TEMPERATURE INSTRUMENTS

Temperature Instruments can be in the form of:

- Temperature gauges
- Temperature transmitters

CONTROL VALVES

Control valves can be used to measure the following:

- Temperature
- Pressure
- Flow

FLOW INSTRUMENTS

Flow rates can be monitored by the use of the following:

- Orifice plates (most commonly used)
- Pitot tubes, Venturi tubes
- Annubar and Coriolis meters

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00014-X

14.2 INSTRUMENT LOCATIONS

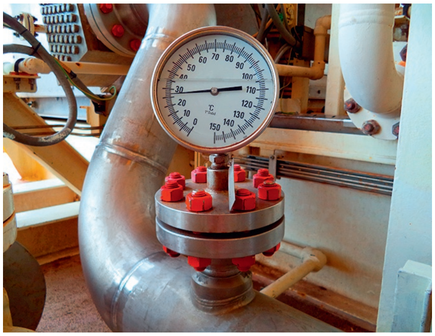
LEVEL INSTRUMENTS

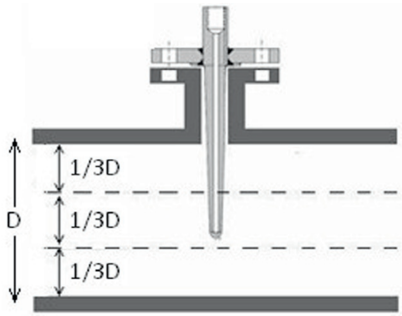
Level transmitter

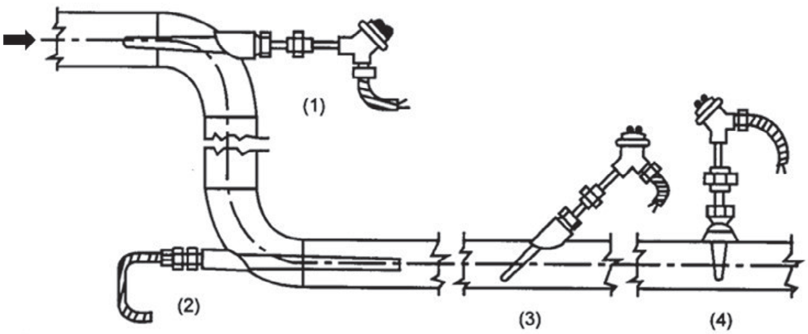
PRESSURE INSTRUMENTS

Photo showing pressure gauges

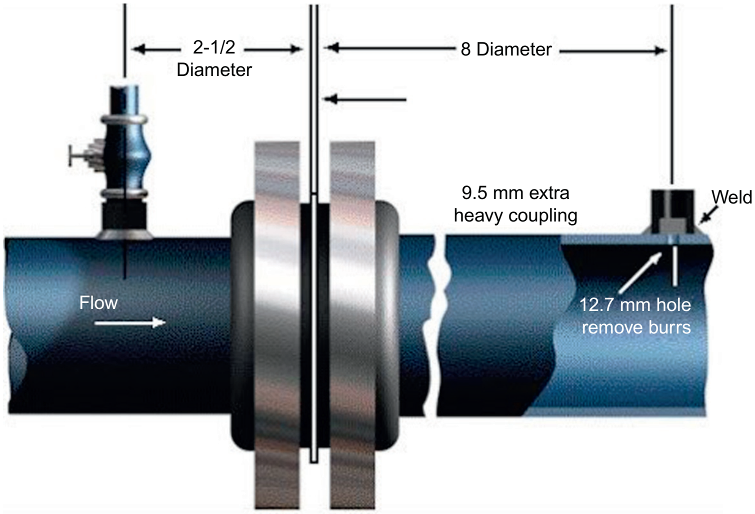
TEMPERATURE INSTRUMENTS

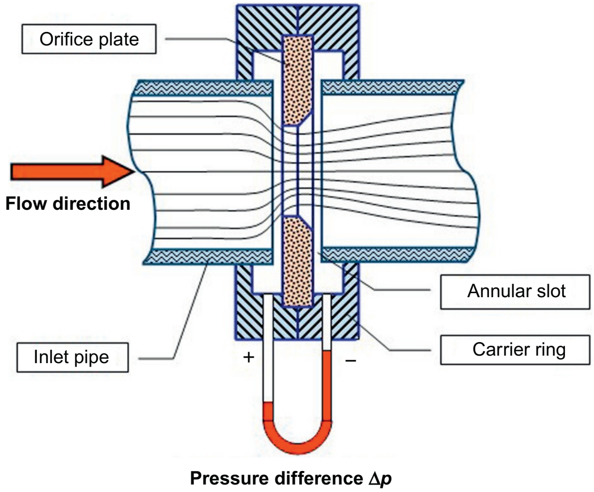






ORIFICE PLATES



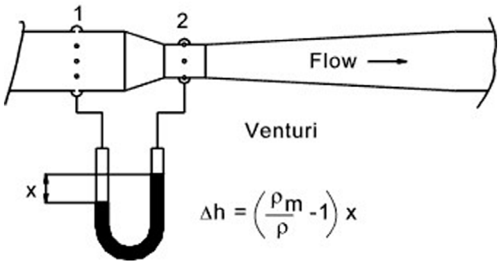


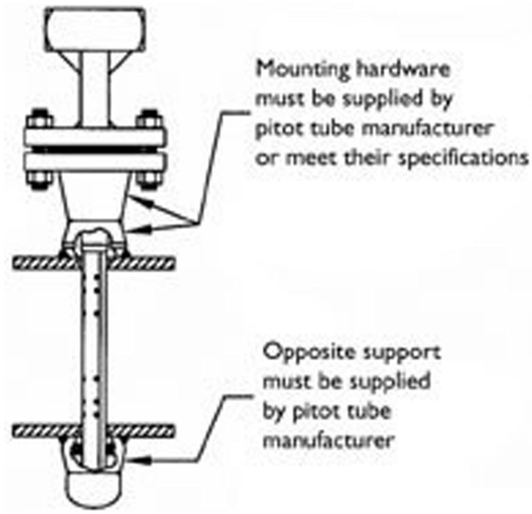
ORIFICE PLATES

These operate by measuring the pressure drop across an orifice plate. On the upstream side of the plate the pressure is higher than on the downstream side because of the constriction of the diameter of the hole in the orifice plate. The pressure differential can be calculated and converted to flow rate and this is programmed into the instrument readout on the control panel or remote flow gauge.

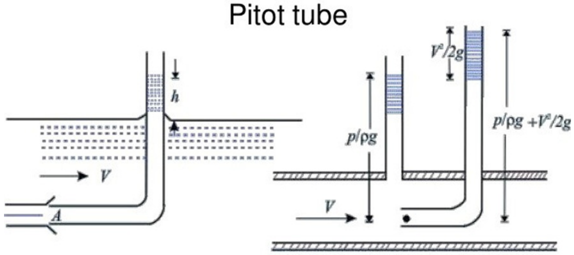
VENTURI TUBES

A **Venturi** works by reducing the fluid pressure, this happens when a fluid flows through a constricted section of pipe. The Venturi effect is named after Italian physicist Giovanni Battista Venturi (1746–1822)





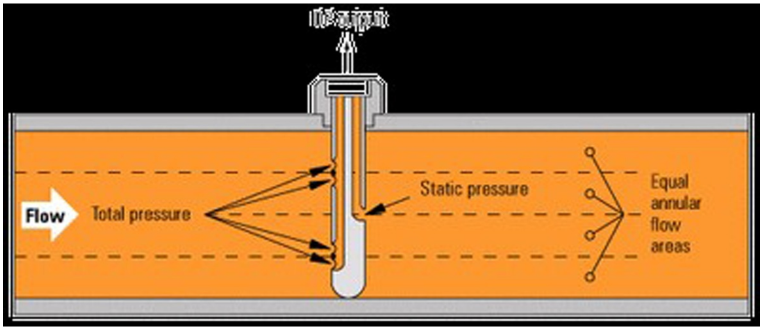
Pitot tube



➢A pitot tube is a simple device used for meausuring the velocity of a flow at the required point in a pipe or steam.
➢It is also called as impact tube or stagnation tube.

PITOT TUBE

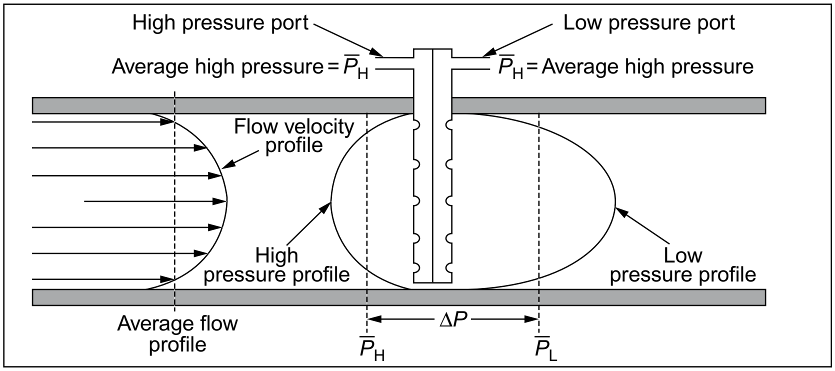
A **Pitot** tube is a pressure measurement instrument used to measure fluid flow velocity. The Pitot tube was invented by the French engineer Henri Pitot in the early 18th century’ and was modified to its modern form in the mid-19th century by French scientist Henry Darcy.



ANNUBAR

An Annubar is similar to a Pitot tube used to measure the flow of gas or liquid. The biggest difference between an **Annubar** and a **Pitot** tube is that an **Annubar** takes multiple samples across a section of a pipe.

An **Annubar** averages the differential pressures encountered accounting for variations in flow across the section.



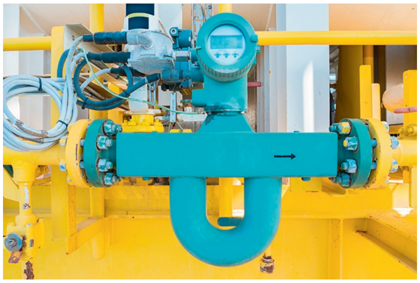
Averaging pitot tube (annubar)

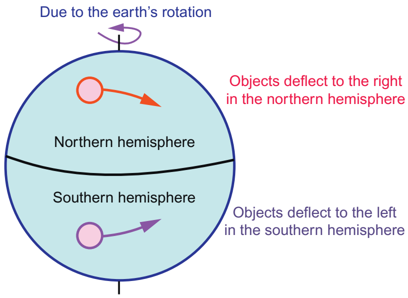
CORIOLIS METERS

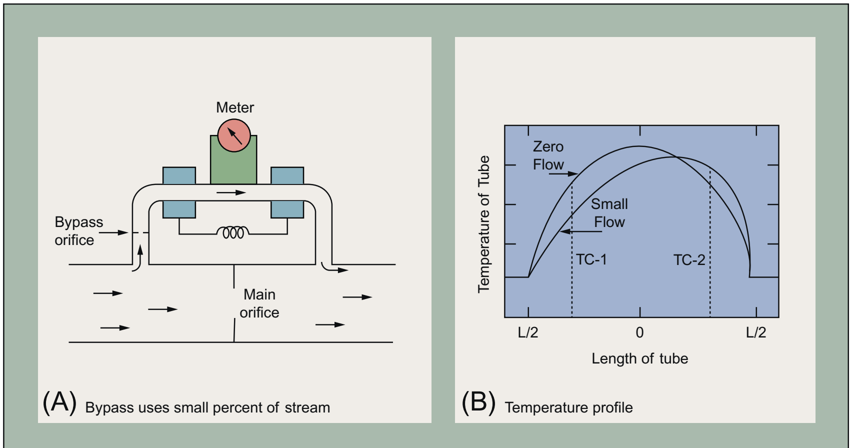
A Coriolis meter, also known as a mass flow meter and as an inertial flow meter, is a device that measures mass flow rate of a fluid traveling through a tube.

The mass flow rate is the mass of the fluid traveling past a fixed point per unit time.

There are two basic configurations of **Coriolis** flow meter: the curved tube flow meter and the straight tube flow meter.







The bypass flowmeter design

The Coriolis meter (mass flow meter) does not measure the volume per unit time(e.g., cubic meters per second) passing through the device; it measures the mass per unit time (e.g., kilograms per second) flowing through the device.

14.3 BETA RATIOS AND INSTRUMENT POSITIONS

Flow instruments used for measurement such as Orifice Plates, Venturi Tubes, Pitot Tube, and Pitot Venturi, require a certain number of upstream and downstream diameters from the measurement point, in the case of an orifice plate from the orifice opening in the plate, to reduce turbulence which can affect the accurate measurement of the flow rate due to turbulence.

The following illustration and chart show the correct locations for the placement of the instrument and also the correct upstream and downstream pipe diameters required to reduce turbulence dependent on the piping configurations used.

A_1 (31Φ)	A_2 (39Φ)	B_1 (6Φ)	B_2 (4Φ)
WHEN PRECEDED BY ANY TYPE BEND, FITTING, INCREASER, REDUCER, WIDE OPEN GATE VALVE, PLUG COCK OR EQUIPMENT CONNECTION.	WHEN PRECEDED BY CONTROL VALVE, GLOBE VALVE OR THROTTLING GATE VALVE. (CASE 6, FIGURE II)	WHEN FOLLOWED BY CONTROL VALVE, REGULATOR, STOP CHECK VALVE, PARTLY THROTTLED GATE VALVE.	WHEN FOLLOWED BY WIDE OPEN GATE VALVE, ANY TYPE BEND, FITTING, INCREASER, REDUCER OR EQUIPMENT CONNECTION

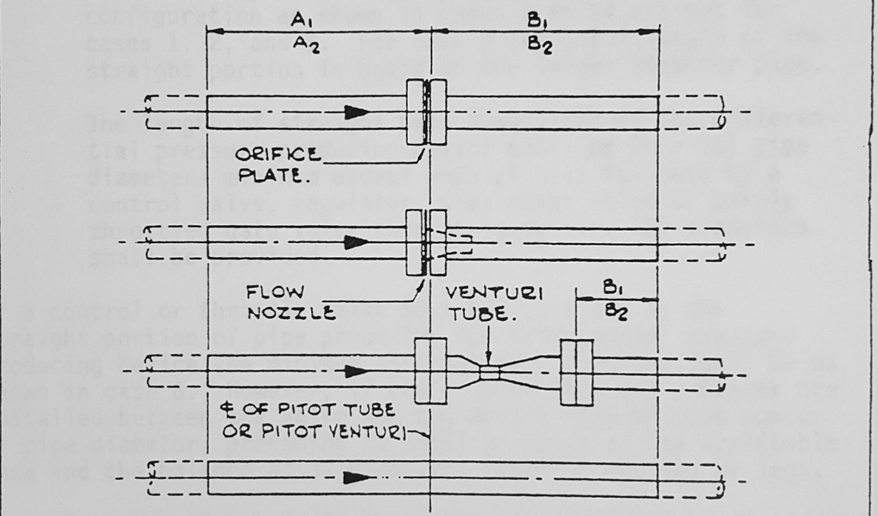


FIGURE 1

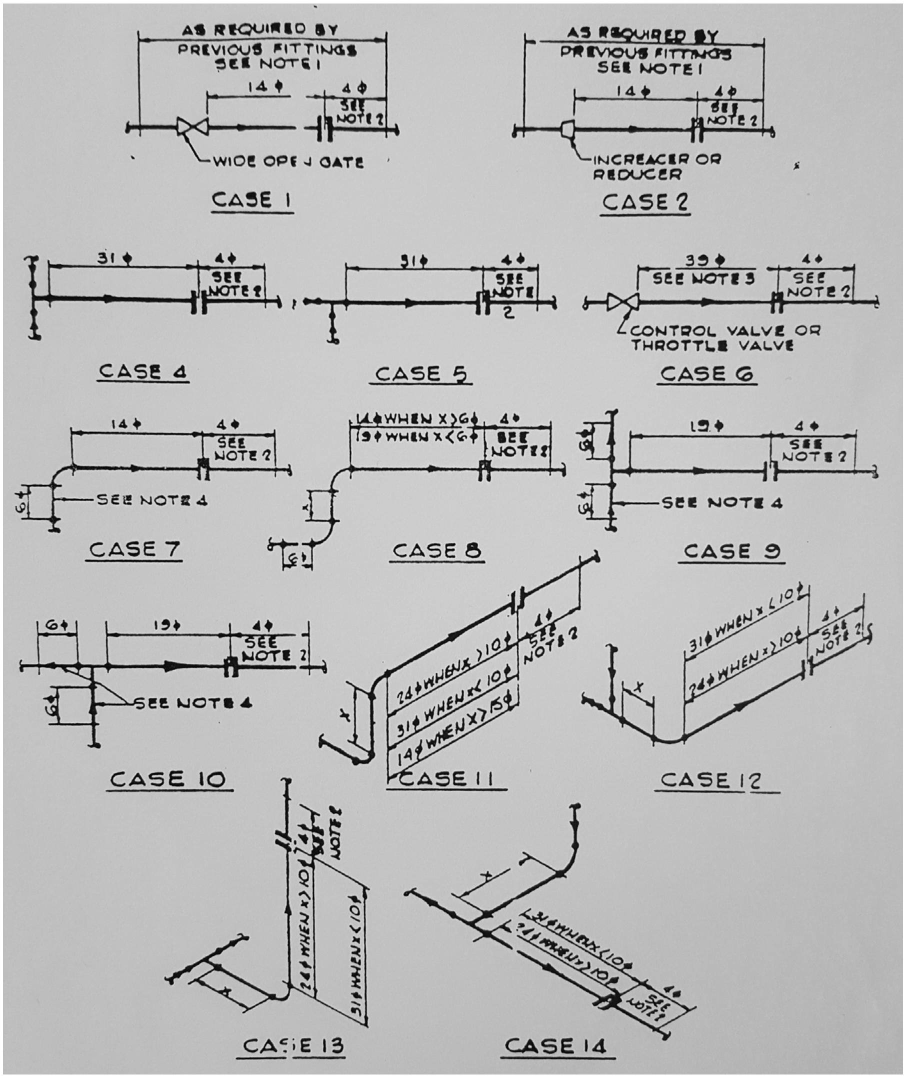
TABLE 1

LINE SIZE	2"	2½"	3"	4"	6"	8"	10"	12"	14"	16"	18"	20"	24"
A_1	5'-2"	6'-6"	7'-9"	10'-4"	15'-6"	20'-8"	25'-10"	31'-0"	36'-2"	41'-4"	46'-6"	51'-8"	62'-0"
A_2	6'-6"	8'-2"	9'-9"	13'-0"	19'-6"	26'-0"	32'-6"	39'-0"	45'-6"	52'-0"	58'-6"	65'-0"	78'-0"
B_1	12"	15"	18"	2'-0"	3'-0"	4'-0"	5'-0"	6'-0"	6'-6"	7'-0"	7'-6"	8'-6"	10'-0"
B_2	8"	10"	12"	16"	2'-0"	2'-8"	3'-4"	4'-0"	4'-8"	5'-4"	6'-0"	6'-8"	8'-0"

TABLE 1

DIMENSIONS IN MILLIMETRES.

LINE SIZE	2"	2½"	3"	4"	6"	8"	10"	12"	14"	16"	18"	20"	24"
A_1	1580	1970	2370	3150	4730	6300	7880	9450	11030	12600	14180	15750	18900
A_2	1990	2480	2980	3970	5950	7930	9910	11890	13870	15850	17840	19820	23780
B_1	310	390	460	610	920	1220	1530	1830	1990	2140	2290	2600	3050
B_2	210	260	310	410	610	820	1020	1220	1430	1630	1830	2040	2440



AS REQUIRED BY PREVIOUS FITTINGS SEE NOTE 1
WIDE OPEN GATE
CASE 1
INCREACER OR REDUCER
CASE 2
CASE 4
CASE 5
SEE NOTE 3
CONTROL VALVE OR THROTTLE VALVE
CASE 6
SEE NOTE 4
CASE 7
14ϕ WHEN X>6ϕ
19ϕ WHEN X<6ϕ
CASE 8
CASE 9
CASE 10
24ϕ WHEN X>10ϕ
24ϕ WHEN X<10ϕ
31ϕ WHEN X>15ϕ
14ϕ WHEN X>15ϕ
CASE 11
31ϕ WHEN X<10ϕ
24ϕ WHEN X>10ϕ
CASE 12
CASE 13
CASE 14

Position of Flowing Line for Type of Differential Pressure-producing Device Used					
Fluid Medium	**Concentric Orifice Plate**	**Tap Location for Horizontal Lines**	**Venturi Tube**	**Flow Nozzle**	**Pitot Tube or Pitot Venturi**
Clean Liquid	Horizontal or vertical upward or downward flow	Horizontal	Horizontal or vertical upward or downward flow	Horizontal or vertical downward flow only	Horizontal or vertical upward or downward flow
Liquid with solids in suspension	Vertical downward flow only	Horizontal	Horizontal or vertical upward or downward flow	Horizontal or vertical downward flow only	
Liquid vapor	Horizontal or vertical upward flow only	Horizontal	Horizontal or vertical upward or downward flow	Horizontal only	
Saturated Steam	Horizontal or vertical downward flow only	Horizontal (45° down if required)	Horizontal or vertical upward or downward flow	Horizontal or vertical downward flow only	
Superheated steam (50° higher)	Horizontal or vertical upward or downward flow	Horizontal (45° down if required)	Horizontal or vertical upward or downward flow	Horizontal or vertical downward flow only	
Dry gas or air	Horizontal or vertical upward or downward flow	Vertical	Horizontal or vertical upward or downward flow	Horizontal or vertical downward flow only	Horizontal or vertical upward or downward flow
Wet gas or air	Horizontal or vertical downward flow only	Horizontal	Horizontal or vertical upward or downward flow	Horizontal or vertical downward flow only	Horizontal or vertical upward or downward flow

CHAPTER

Storage tanks

15

15.1 CODES AND REGULATIONS

The layout of process storage tanks requires strict observance of codes.

The following codes shall be reviewed when designing tank layouts:

- National Fire Protection Association (NFPA)
- Occupational Safety and Health Act (OSHA)
- National and Local codes and jurisdictions
- Earthquake codes (if applicable)
- Client Specifications and design philosophy

Other important design considerations that will affect layout are:

- Topography
- Access roads
- Railroads
- Local habitation
- Office buildings
- Control rooms
- Process units

NATIONAL FIRE PROTECTION ASSOCIATION (NFPA)

Before tank layout commences the **NFPA** codes must be read for compliance.

An example of the codes that might affect the layout are:

- NFPA 30—flammable and combustible liquids code
- NFPA 58—storage and handling of liquefied petroleum gas
- NFPA 59A—production storage and handling of liquefied natural gas
- NFPA 321—basic classification of flammable and combustible liquids
- NFPA 11—low expansion foam and combined agent systems

The **NFPA** codes are the basis for tank regulations.

They were compiled to reduce any potential hazards to public safety. It must be remembered that although compliance to the codes does not eliminate hazards when flammable and combustible liquids are stored in process facilities, the aim is to reduce the possibility of a hazard.

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00015-1

OCCUPATIONAL SAFETY AND HEALTH ACT (OSHA)

OSHA regulations with regard to the layout of storage facilities refer to:

- Access Ladders
- Platforms
- Stairways
- Catwalks
- Personnel access
- Safety at works

NATIONAL AND LOCAL CODES AND REGULATIONS

All the relevant documents that refer to both the **national** and **local codes** shall be reviewed before any plant layout is started.

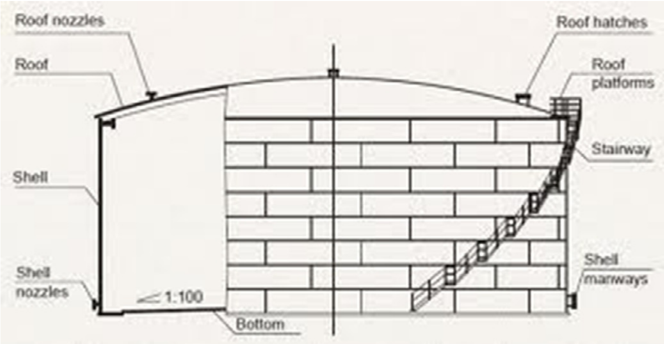
When designing overseas facilities, it is mandatory to refer to the **national codes** of the country and also to their local codes as well as to **international codes and regulations.**

15.2 TYPES OF TANKS

Atmospheric storage tank—this type of tank operates from atmospheric pressure to 0.5 psi/0.034 bar.

Photo of an atmospheric storage tank

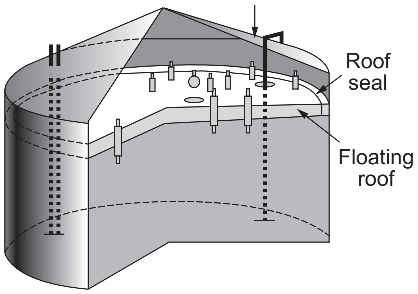
Cone Roof Tank—this type of tank is a low-pressure storage tank with a fixed, cone-shaped roof



Drawing of coned roof tank

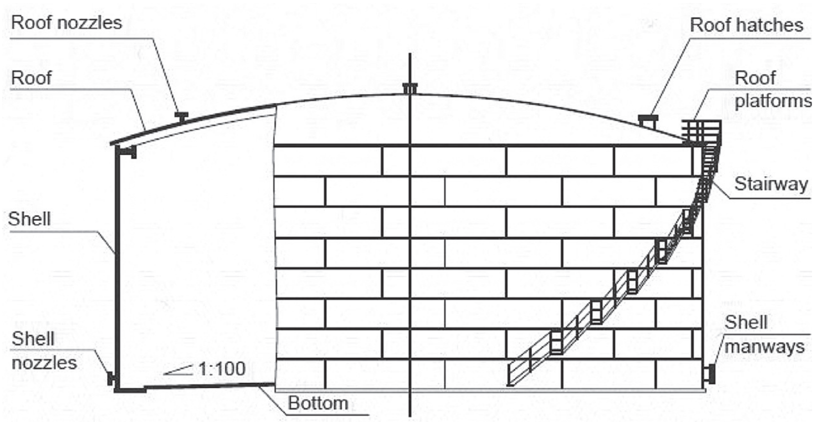
Photo of coned roof storage tanks

Closed floating roof tank—this has an internal floating roof but eliminates natural ventilation of the tank vapor space. Instead, the CFRT is equipped with a pressure-vacuum (PV) vent and may even include a gas blanketing system such as that used with fixed roof tanks, these tanks are designed as in **Appendix C** of the **API Standard 650**



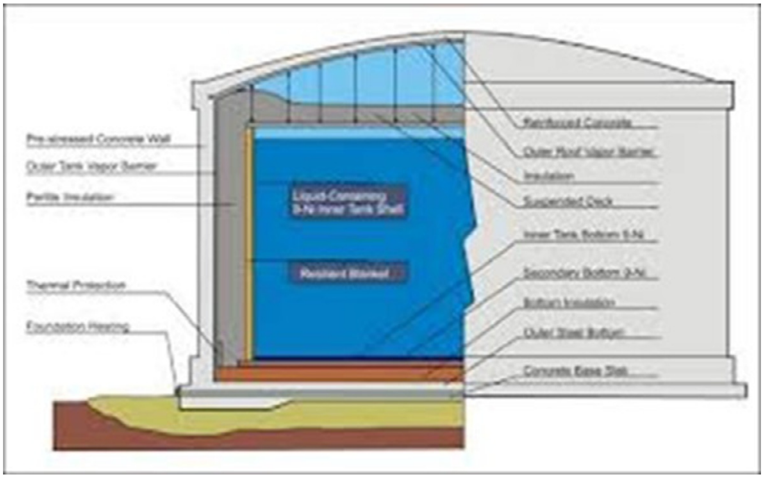
Closed floating roof tank

Fixed roof—this is a low-pressure tank with a roof welded to the shell, regardless of roof design or support methods.



Fixed roof tank

Double wall storage tank—is a tank with an inner wall to contain a liquid (as used in LNG storage tanks), it has an annulus space filled with insulation and an outer wall.



Double wall storage tank

Bullet—this type of tank is a long cylindrical high-pressure storage vessel that is shaped like a bullet.

Photo of bullets

Horton sphere—this is a spherical vessel used to store liquids and gases at high pressure.

Photo of a sphere

Intermediate storage (holding) tank—used for temporary storage of liquid until it reaches a specified state, after which it is pumped downstream for process.

Photo of intermediate storage tanks

15.3 SPILL CONTAINMENT

Owing to the possible risk of failure of a storage tank, an adequate means of spill containment must be provided; this can be in the form of:

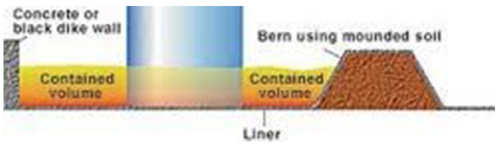
- Second tank wall around the tank
- Containment dike designed to contain the amount of liquid in the largest tank

A containment dike can be constructed of:

- Earth
- Steel
- Concrete
- Masonry

Earth dikes are the most popular followed by **concrete** for smaller containment areas.

Photo of earth dike



Earth berm or concrete / black dike wall

When storing a liquefied gas close to any population center it is mandatory to use a double containment method. This can be in the form of a circular concrete wall surrounded by an earthen dike; this provides a complete spill containment in the event that the primary dike should fail.

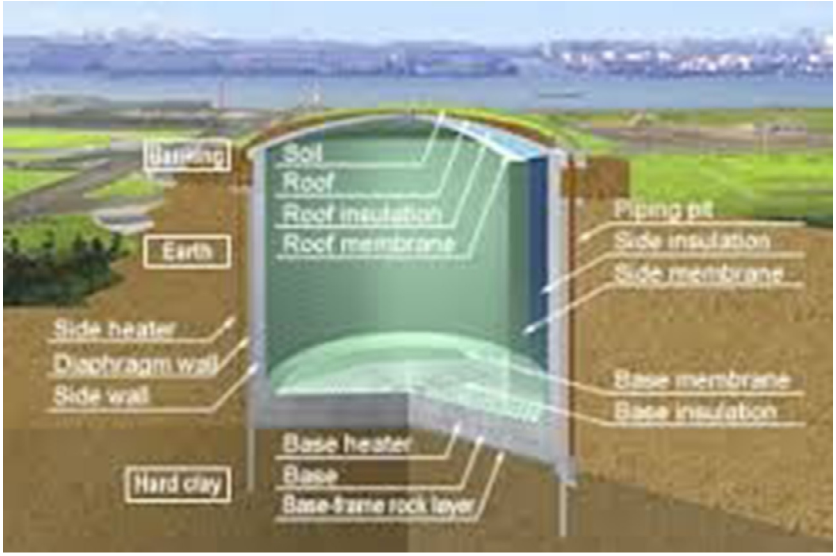
LNG storage tanks showing earth berm

If tanks are located on sloping terrain, use of the slope must be taken into consideration by locating the drainage sumps at the low point. When locating a diked storage area, it should always be at a lower elevation than the process plant, so in the event of spillage liquids will not flow back to the process units.

BURIED STORAGE TANKS

Typical buried petroleum tank at gas station

LNG storage tank



Schematic of buried LNG storage tank

15.4 DIKE ACCESS

Adequate access to diked areas must be considered. Maintenance access is required and this can be in the form of:

- Personnel access by stairways (to OSHA standards)
- Personnel access by stile way over dike walls
- Vehicle ramp (if a ramp is used the maximum grade of the ramp must not exceed 15°)
- Pumps must be located outside the diked area with access from the perimeter roads
- When a new tank farm is located within an existing facility there must be no obstruction from existing equipment or structures

All spacing requirements between the outside wall of the tank and any obstruction or related equipment, roadways or buildings, etc. must conform to **NFPA** and local codes. Studies must be performed for location of fire ring mains, fire hydrants and monitors and deluge systems at diked areas

Adequate roadways should be provided around the diked areas to allow for access egress and firefighting facilities.

15.5 SIZING TANKS AND DIKES

When sizing tanks and dikes the engineer must take into consideration the following:

- Volume of product to be stored
- Reference to API 12F Standardized shop fabricated tank sizes
- Use of standardized tanks for smaller capacities
- Larger field fabricated tanks to be sized and designed to suit the specific site
- Availability of real estate
- Terrain on which it is to be built
- Is it in an earthquake zone?
- Foundation design

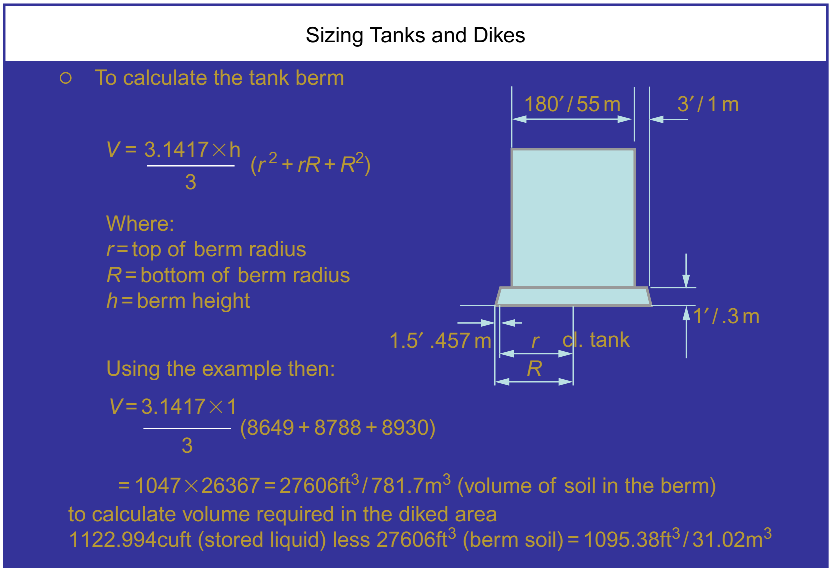
DEVELOPING TANK HEIGHT AND DIKE SIZE

For example, 200,000 barrel (42 US gallons per barrel) 180 ft/55 m dia tank. To convert tank volume to ft^3/m^3

$$\frac{200{,}000 \times 42}{7.48} = 1122.994\,\text{ft}^3/31.8\,\text{m}^3 \text{ liquid}$$

$$\text{Tank height} = \frac{h = 4V}{3.14 \times D^2} = \frac{4 \times 1122.994}{3.1417 \times 180^2} = 44.13\,\text{ft}/13.45\,\text{m}$$

SIZING TANKS AND DIKES



How to size the volume of a tank berm (the volume required in the diked area).

15.6 TANK DETAILS

Top head platforms

Top head platforms

Top platform outside tank wall

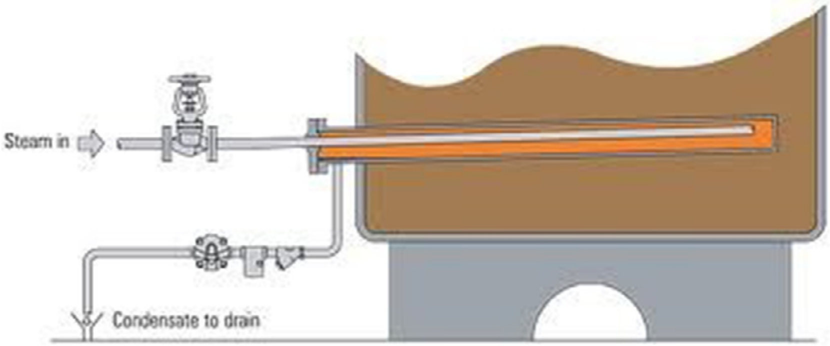
Bottom outlet platform

Circular stairway

Spheres with circular stairs & top platform

Tank farm

Access platform at vertical storage tanks



Steam heater

Finned tube heater

Pipe through bund wall, a pipe sleeve and a suitable seal needs to be provided to seal the pipe in the wall. There are many proprietary seals on the market that can be used for this purpose.

Atmospheric relief vents and **flame arrestors** are used on storage tanks. A **flame arrester** is a device that stops fuel combustion by extinguishing the flame.

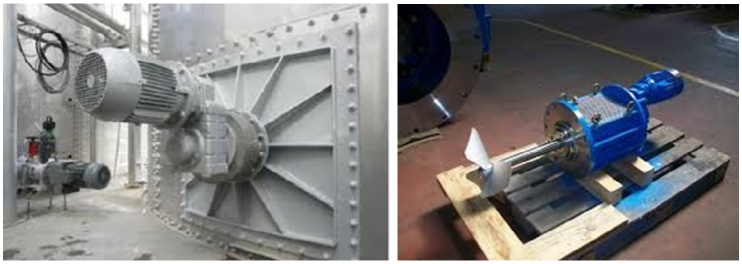
Flame arresters are used:

- to stop the spread of an open fire
- to limit the spread of an explosive event that has occurred
- to protect potentially explosive mixtures from igniting
- to confine fire within an enclosed, controlled, or regulated location
- to stop the propagation of a flame traveling at subsonic velocities

They are commonly used on fuel storage tank vents.

ATMOSPHERIC RELIEF VENTS

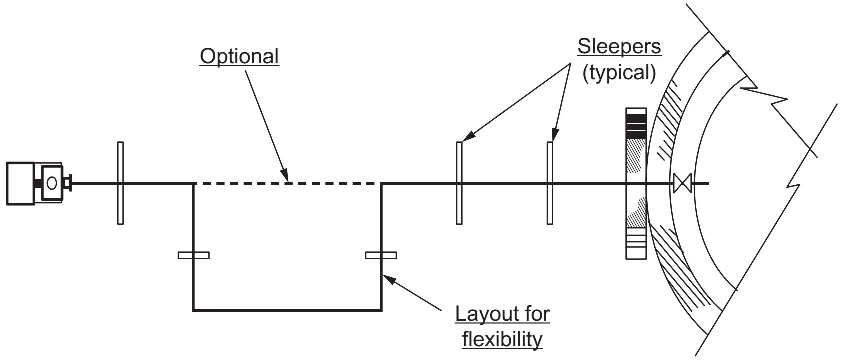
Atmospheric relief vents



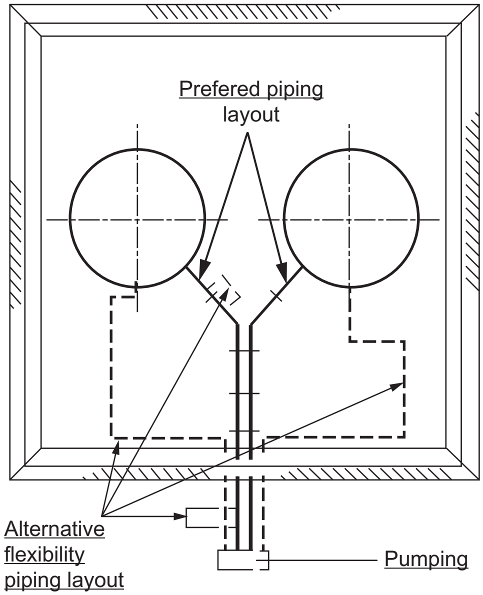
Tank mixers

Piping arrangements at tank farms

Piping arrangement at tank farm



Piping showing expansion loops, tanks settlement must be allowed for when setting the sleepers



Piping plan at tank farm

15.7 TANK SUPPORTS

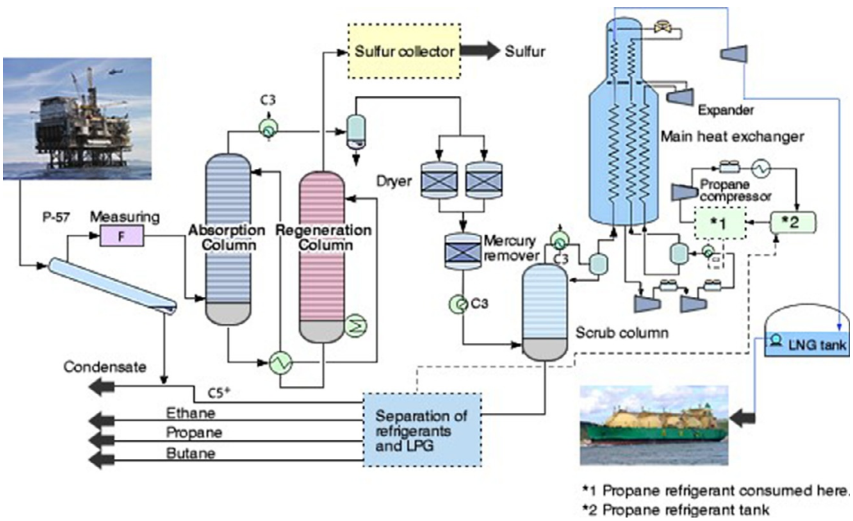
Manway & support legs

Horizontal vessel with saddle

Vertical storage tanks with legs

Tank farm storage on berm

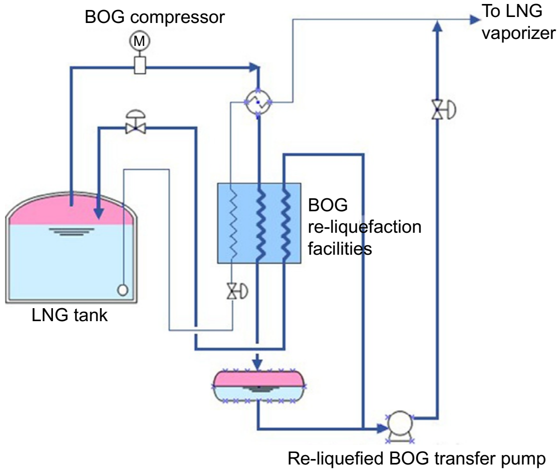
15.8 LNG STORAGE TANKS



LNG flow diagram

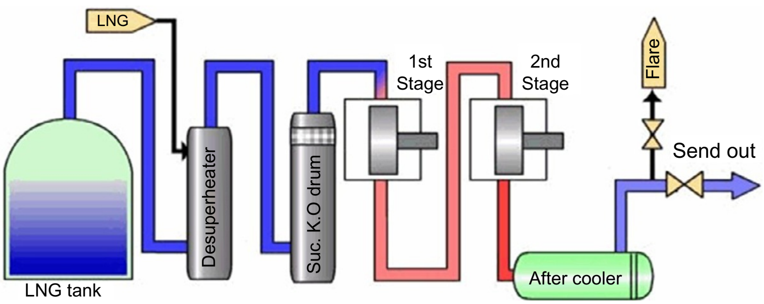
LNG FLOW DIAGRAMS

Flow of the BOG re-liquefaction process

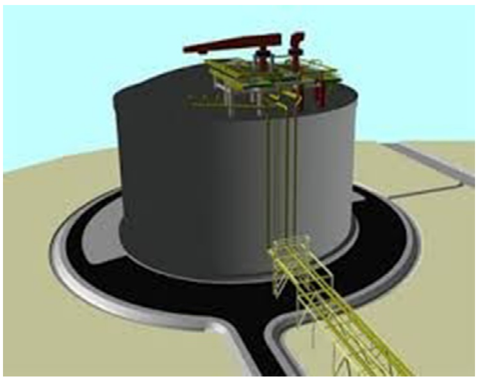


BOG re-liquefaction flow diagram

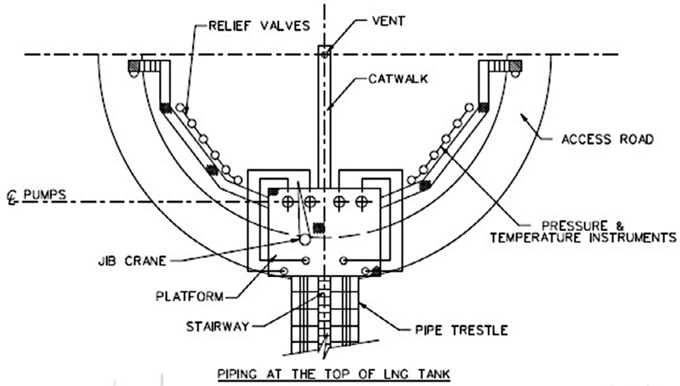
Compressor running

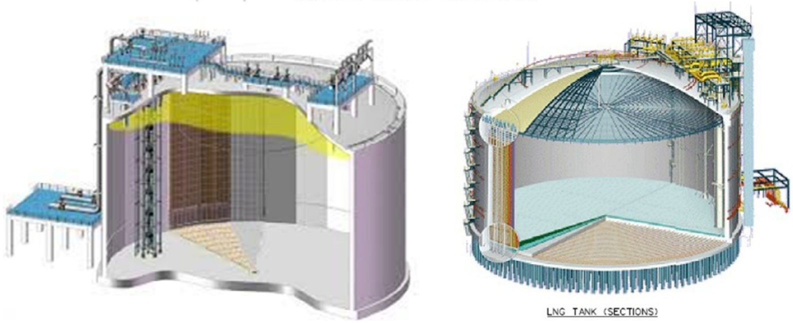


Quick start-up system



LNG tank





Sections through an LNG tank

LNG tank showing piping

CHAPTER

Utility stations, steam and condensate piping

16

16.1 STEAM PIPING

Steam—is water vapor, the gaseous phase of water, which is formed when water boils, it is the visible mist of water droplets formed as this water vapor condenses in the presence of cooler air.

Water boils at a temperature of 212°F/100°C (standard temperature and pressure). At lower pressures, water boils at temperatures lower than 212°F/100°C.

If heated further it becomes "**Superheated steam**." The energy required to turn water into its gaseous form is called the "**enthalpy of vaporization**." Steam is produced by heating a boiler via burning coal, gas, and other fuels. Water vapor that includes water droplets is described as **wet steam**. As wet steam is heated further, the droplets evaporate, and at a high enough temperature (which depends on the pressure), all the water evaporates and the system is in vapor-liquid equilibrium.

Superheated steam is steam at a temperature higher than its boiling point for the pressure which only occurs where all the water has evaporated or has been removed from the system. Steam tables contain thermodynamic data for water/steam and are used by engineers in the design and operation of equipment where thermodynamic cycles involving steam are used. Thermodynamic phase diagrams for water/steam, such as a temperature-entropy diagram or a Mollier diagram may be used. Steam charts are also used for analyzing thermodynamic cycles. Layout of steam piping must take into consideration thermal growth. As piping gains temperature, it also gains in length (thermal expansion).

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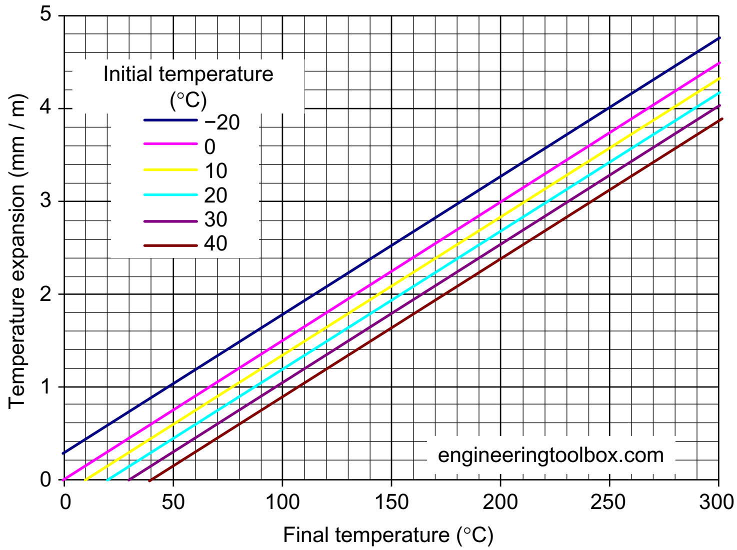
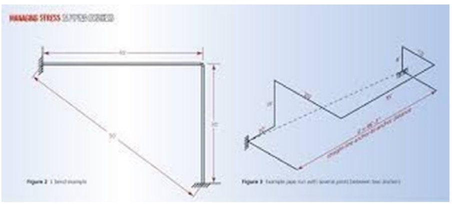
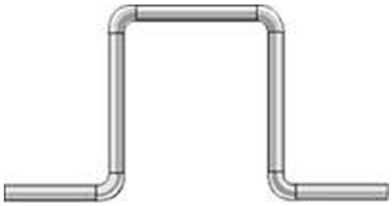


Expansion tables for carbon steel pipe

Thermal expansion of steam piping can be absorbed by the use of loops and L-shaped, U-shaped and Z-shaped loops.

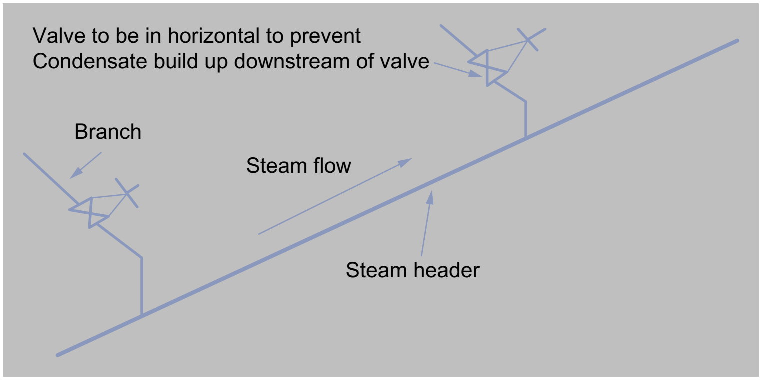




These expansion legs absorb the longitudinal expansion and contraction in the line due to temperature changes. We will go into greater details of expansion and stresses in Chapter 19. Generation of steam in the piping system causes a buildup of condensate that must be removed from the system.

STEAM PIPING

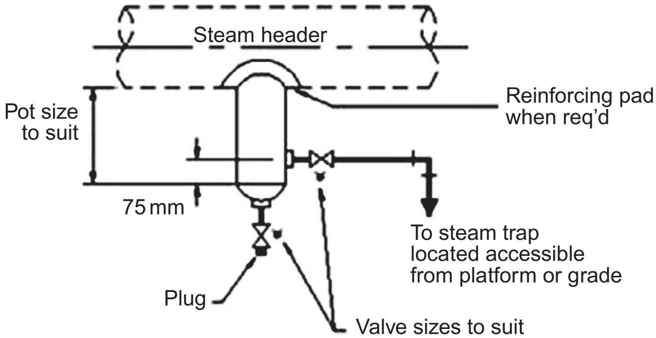
Take offs for subheaders must always be taken from the top of the steam header.

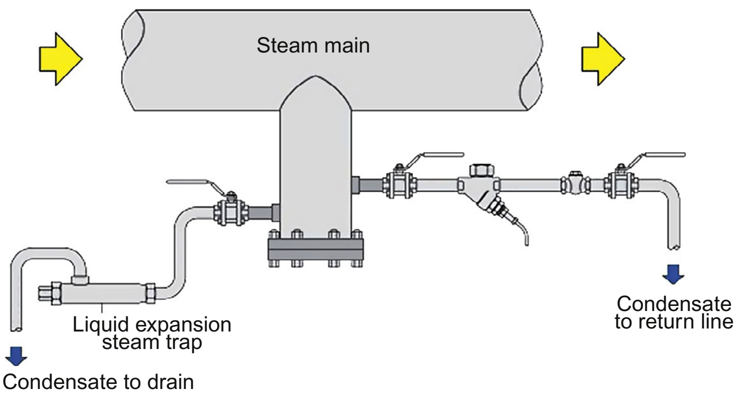


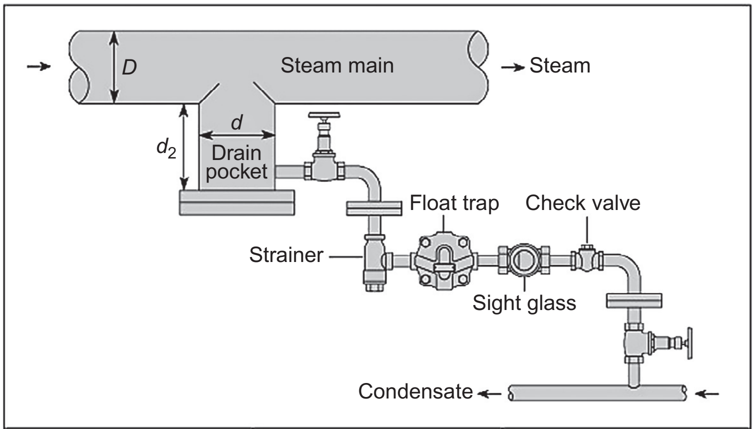
Drawing showing steam header take offs

16.2 DRIP LEGS

Steam piping systems contain **condensate** which must be removed. **Condensate** can be removed from the system by the use of **drip legs** and **steam traps**





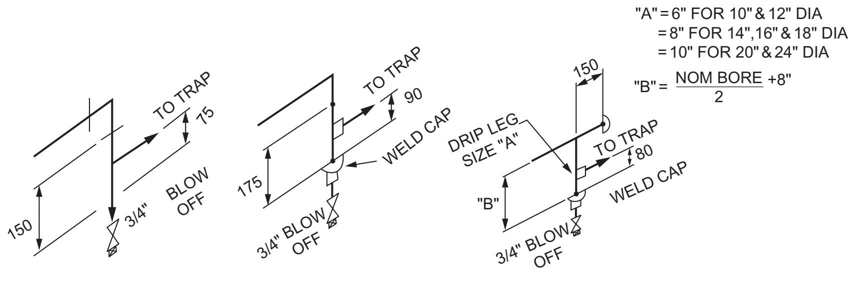


Main diameter ***D***	Pocket diameter ***d_1***	Pocket depth ***d_2***
Up to 100 mm	d_1 = D	Minimum d_2 = 100 mm
125–200 mm	d_1 = 100 mm	Minimum d_2 = 150 mm
250 mm and above	$d_1 = D/2$	Minimum $d_2 = D$

Drip leg schematic

Photo of Drip Leg on Steam Line

DRIP LEGS COLLECT CONDENSATE FROM THE STEAM LINE



Drip leg for lines 2" & below

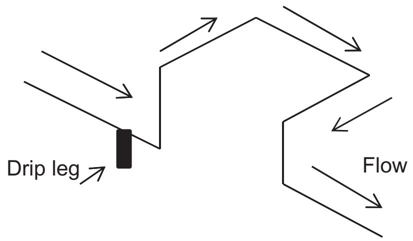
Drip leg for lines 2 ½' – 8"

Drip leg for lines 10" – 24"

They are located at all the low points on a steam system and at intervals along the steam headers.

Drip legs on main steam header should be located at intervals of between 100′ and 200′/30–60 m. it is also preferable to slope the steam header to allow drainage although there is enough pressure in the header to move the condensate without sloping.

Drip legs should also be located before a rise in elevation of the steam line, for example, before the vertical leg of a steam expansion loop.



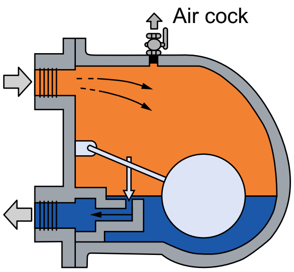
16.3 STEAM TRAPS

Steam traps are used to remove condensate from steam headers, steam subheaders, upstream at control stations and expansion loops, heating coils, condensing equipment, reboilers, steam tracing manifolds, and steam tracing lines. The function of the **steam trap** is to remove both air and noncondensable gases from the steam system. If air was not removed from the system you would get uneven heating, increased corrosion, at the worst, it would prevent steam from entering the equipment and heat transfer would not be possible. The **steam trap** is designed to close in the presence of steam and drain the condensate. As the steam condenses into a liquid, it gives up its latent heat. The latent heat results in lb, for lb the steam releasing more energy than the water. The **steam traps** purpose is to prevent the steam leaving the system before it gives up its latent energy. As steam gives up its latent heat it changes state from vapor to liquid. The liquid is known as condensate. If this condensate is not removed then it will result in incomplete heat transfer and possible water hammer. To enable the collection of the condensate, a **drip leg** must be located in the steam line. The **drip legs** must be located at every low point in the steam system. On long horizontal runs of pipe it is necessary to provide drip legs and steam traps at intervals along the pipe.

There are three categories of **steam traps**

- Mechanical (Ball Float, Inverted Bucket)
- Thermodynamic (Impulse, Controlled Disk)
- Thermostatic (Temperature Sensitive Traps)

BALL FLOAT TRAPS

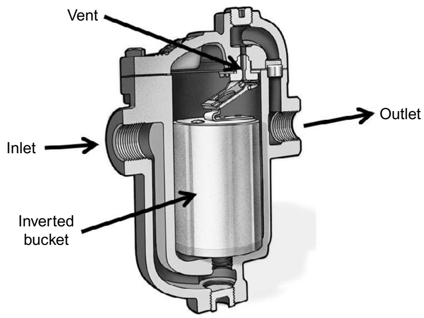


Ball float traps schematic

Ball float trap photo

INVERTED BUCKET TRAP

Inverted bucket traps are the most reliable type of trap—the lever system opens the valve against pressure.

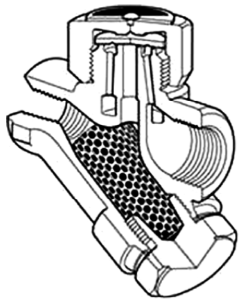


Inverted bucket trap schematic

Photo of inverted bucket trap

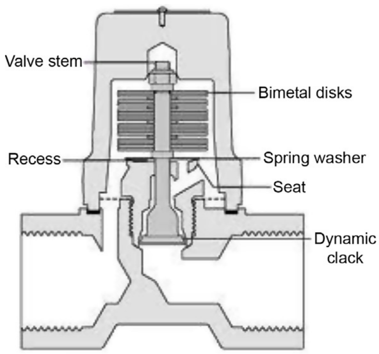
THERMODYNAMIC STEAM TRAP

Thermodynamic steam traps operates by the dynamic effect of flash steam as it passes through the trap.



Thermodynamic steam trap schematic

Thermodynamic steam trap photo



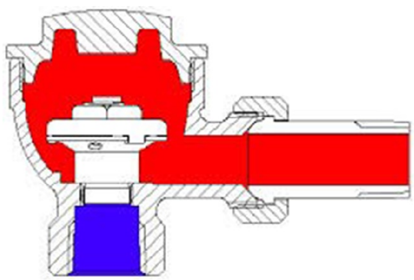
Schematic

Photo

Bi-metallic thermodynamic steam traps

THERMODYNAMIC STEAM TRAP

There are two types of thermostatic static and balanced pressure



Balanced pressure steam traps

Bi-metallic thermodynamic steam traps

STEAM TRAP SELECTION

Trap Type	Float & Thermostatic	Inverted Bucket	Thermostatic	Thermodynamic
Response	Fast	Moderate	Moderate	Slow
Air venting	Medium/High	Low	High	Low
Applications	Drip legs Process equipment	Drip legs Process equipment	Drip legs Process equipment tracing	Drip legs tracing
Capacity	High	High	Low	Low
Maintenance	Moderate	Moderate	Easy	Easy
Relative cost	Medium/High	Medium/Low	Low	Low
Capacity	High	High	Medium	Low

< Freezing | > Freezing

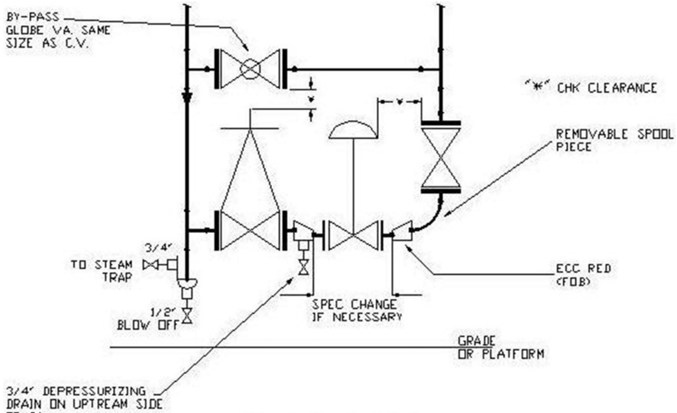
	Characteristic	Inverted Bucket	F&T	Disc	Thermostatic	Differential Controller
A	Method of Operation	Intermittent	Continuous	Intermittent	Intermittent	Continuous
B	Energy conservation (time in service)	Excellent	Good	Poor	Fair	Excellent
C	Resists wear	Excellent	Good	Poor	Fair	Excellent
D	Resists corrosion	Excellent	Good	Excellent	Good	Excellent
E	Resists hydraulic shock	Excellent	Poor	Excellent	Poor	Excellent
F	Vents air and CO_2 at steam temperature	Yes	No	No	No	Yes
G	Vents air at very low pressure (1/4 psig) (0.02 bar)	Poor	Excellent	NR	Good	Excellent
H	Handles start-up air loads	Fair	Excellent	Poor	Excellent	Excellent
I	Operates against back pressure	Excellent	Excellent	Poor	Excellent	Excellent
J	Resists damage from freezing	Good	Poor	Good	Good	Good
K	Can purge system	Excellent	Fair	Excellent	Good	Excellent
L	Performs on very light loads	Excellent	Excellent	Poor	Excellent	Excellent
M	Responds to slugs of condensate	Immediate	Immediate	Delayed	Delayed	Immediate
N	Handles dirt	Excellent	Poor	Poor	Fair	Excellent
O	Comparative physical size	Large	Large	Small	Small	Large
P	Handles 'flash steam'	Fair	Poor	Poor	Poor	Excellent
Q	Mechanical failure (open–closed)	Open	Closed	Open	Open,Closed	Open

First choice | Alternative

16.4 STEAM CONTROL SETS

All low points in a steam line must be trapped, this include control stations.

A drip leg must be located upstream of the control valve.

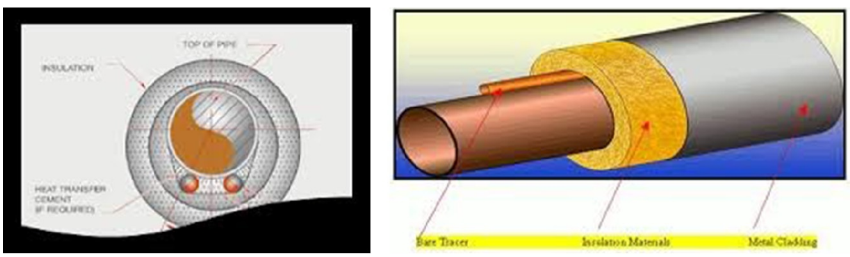


Steam Control Set

16.5 STEAM TRACING

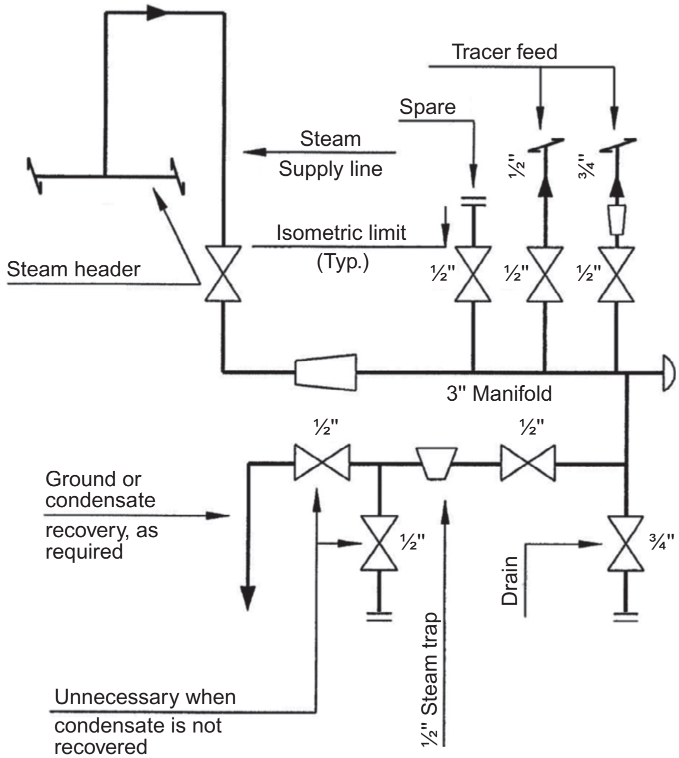
Steam tracing is used for the freeze protection of pipelines. It is used as an alternative to electrical tracing. The steam consumption necessary to enable this freeze protection is dependent on the following:

- Contact between the tracer line and product line
- Line temperature
- Ambient temperature
- Wind speed
- Insulation
- Lengths, temperature, and pressure drop along the tracer lines



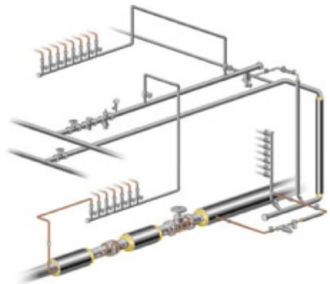
Steam Tracers

Steam tracing lines are small diameter pipes that are a dedicated system fed from a steam supply header. Each tracer must be terminated with a steam trap. To calculate the size of a steam tracer header you must calculate the total cross section of all the tracers and then calculate the header size to allow for the same flow area. The rate of condensate of the tracer depends upon the length of tracer that is in contact with the process line. Line expansion of the steam tracer must also be taken into consideration. The thickness of insulation is determined by the line temperature and tracer size must be allowed for. Tracers should be run parallel to and set against the underside of the pipe that is to be heated. Steam supply to the piping arrangement must be fed to the highest point to allow for drainage, and assist gravity flow to condensate traps. A steam trap is not required at every low point of the tracer system, but must be provided at the end of the tracer. When looping tracers around flanges make sure that unions are provided. Only run one tracer line to each trap.



Steam Tracing Schematic

Steam Tracing Manifold at Column

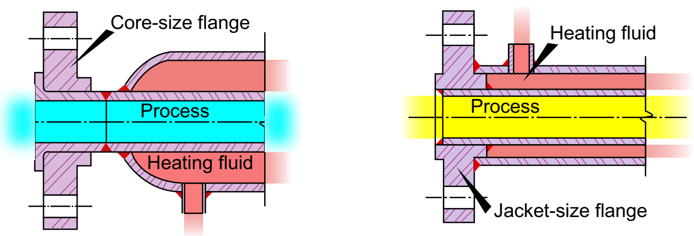


Steam Tracing Isometric Drawing arrangement

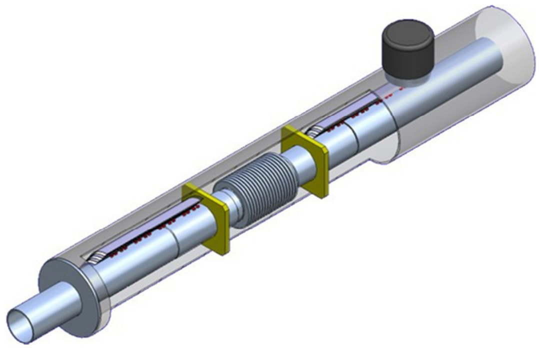
16.6 JACKETED LINES

Jacketed piping is also used for process heating requirements of a pipeline.

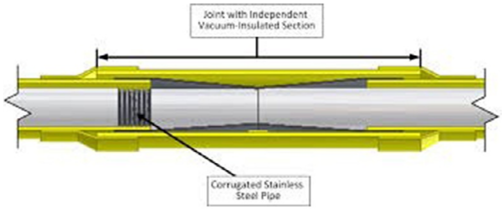
- Jacketed Lines are used for the continuous heating of a process line
- Jacketed line can be fed by **steam** or **hot oil** or **glycol**
- Jacketed lines are fabricated in flanged sections



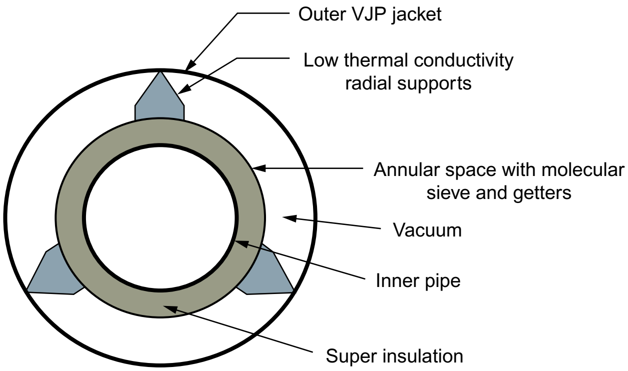
Schematics showing jacket at flange and sections of jacketed pipework



LNG lines use jacketed lines to keep them cold. They do not use steam or oil they use vacuum insulation.

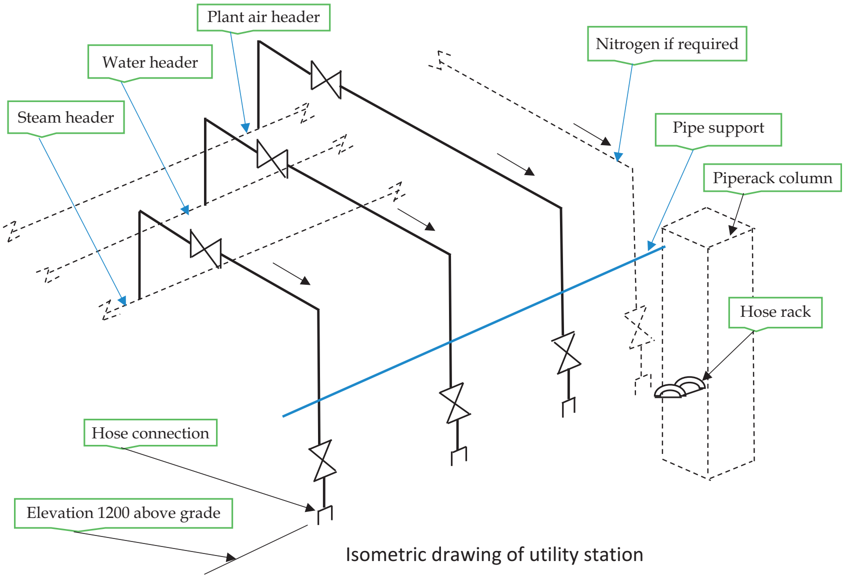


Vacuum Jacketed Insulation



Section through Jacketed Line

16.7 UTILITY HOSE STATIONS



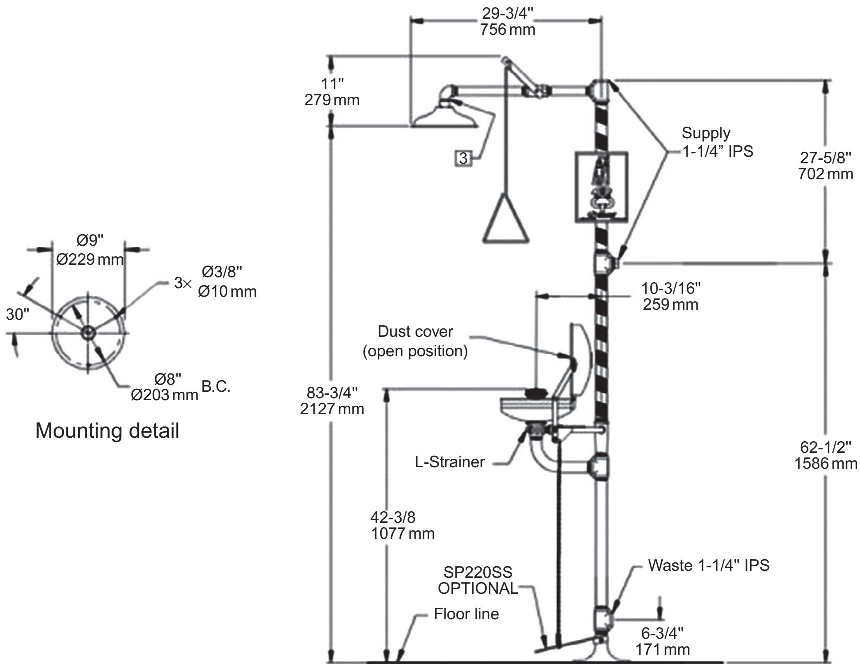
Isometric drawing of utility station

Hose Station at Platform

Hose Station in Chemical Plant

16.8 SAFETY SHOWERS

Safety showers and eyewashes are required everywhere that there is a chance of coming into contact with chemicals or hazardous products.



Eyewash & Safety Shower signs

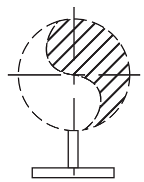
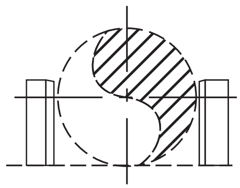
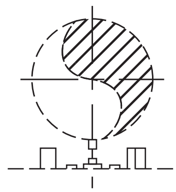
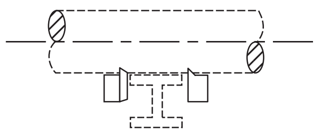
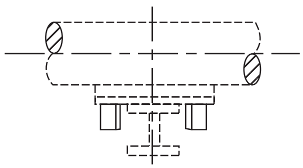

Eyewash


Eyewash and Safety Shower

Pipe supports selection, anchors—guides 17

17.1 SELECTION

The following graphics show pipe support shoes, guides, and restraints.

Typical pipe support details	Shoe 
Guide—no shoe 	Guide—w/ shoe 
Directional anchor—no shoe 	Directional anchor—w/ shoe 

Selection of pipe supports must take into consideration:

- Location
  - Total plot plan must be considered and established.
- Configuration
  - Where is the pipe located—rack free standing—at equipment, is it on a pipe rack?—shape of piping system—adequacy of support.

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00017-5

- Materials
  - Carbon steel, stainless steel, etc.—what would be the required material to match the pipe, would liners be required between the support and pipe if different materials.
- Hot or cold line
  - Line temperature—hot or cryogenic—line expansion or shrinkage—line movement—line lift off—are spring supports required.
- Insulation or bare pipe
  - Is hot or cold insulation to be used on the pipe—insulation materials to be used.

In the case of a pipe rack you must consider:

- Height
  - Should they be sleepers or rack?
  - If a rack, then how high must each rack level be?
  - What are the line sizes to be carried on the rack?
  - What is the largest line size to come off and onto the rack?
  - Wind loads?
  - Earthquake zone?
- Width
  - Sizes and number of lines to be accommodate on rack
  - Future space allowance
  - Allowance for cable and instrument trays
- Spacing
  - Allowance for expansion of hot lines
  - Number of lines—sizes of lines
  - Flanges required on lines in rack—flange spacing’s
- Materials of construction
  - Materials required and method of fabrication of supports

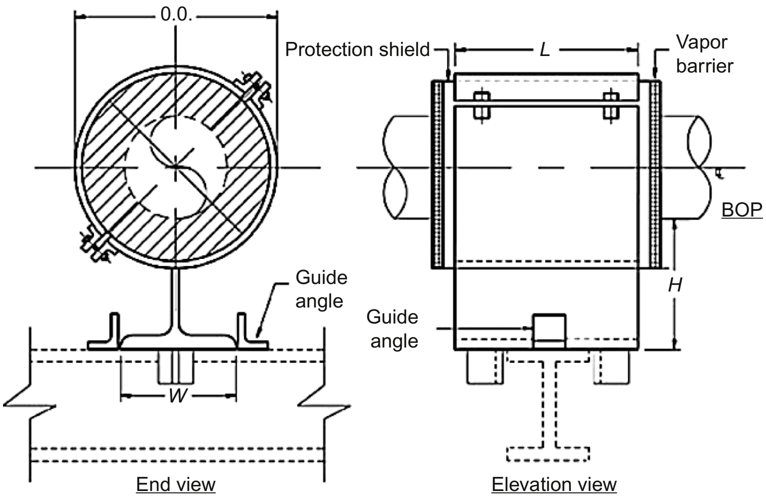
17.2 ANCHORS

An **Anchor** prevents any movement of the pipe line, and as such is a rigid point

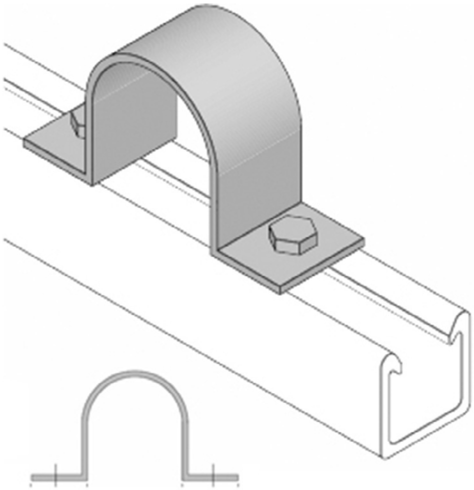
Anchors are used primarily in pipe racks; however, they can be used at any location where an anchor point is deemed necessary by the **stress engineer**.

Anchors can either be:

Welded Shoe
(used for more extreme loads)

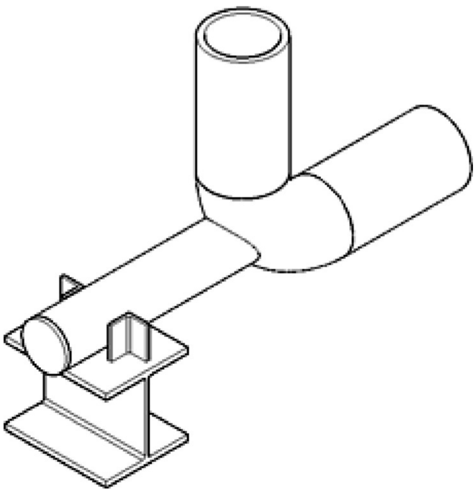


Guide and Restraining Angles



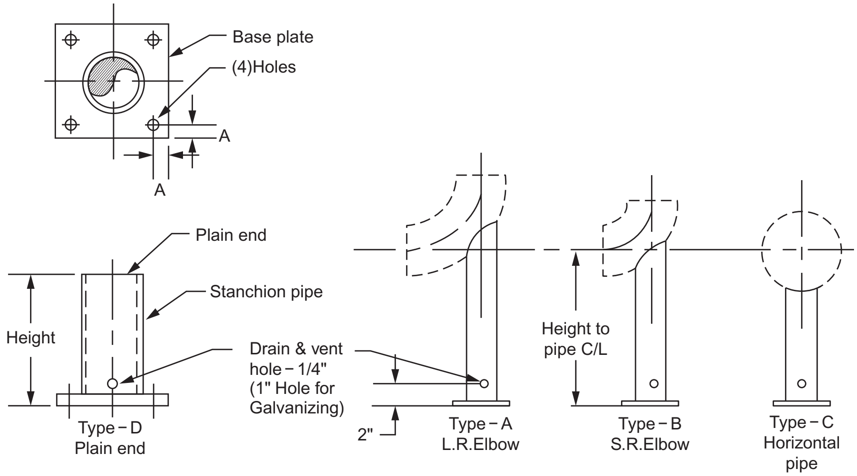
Rigid clamps (used for light loads)

BASE ANCHORS



Base anchors are typically used at grade for anchoring the upstream side of control stations.

Base anchors are also referred to as dummy ends.



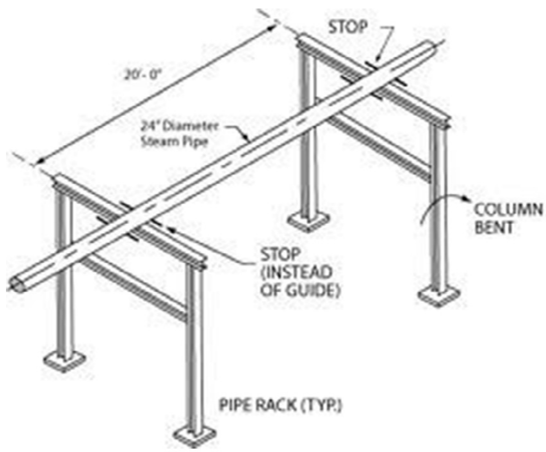
Drawing showing types of base anchors (dummy ends)

Anchors can either be fixed or directional, the previous slides showed **fixed anchors.** A **directional anchor** used for hot lines and restricts the movement of a line in a specific direction (axis).

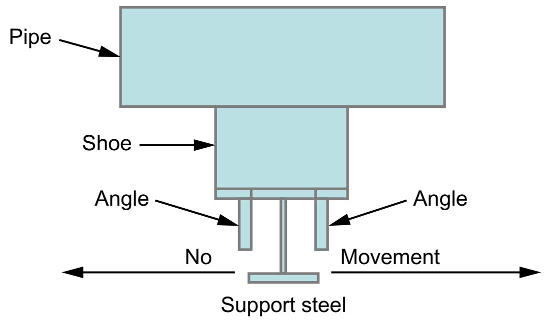
Directional anchors are designed in two ways:

- Longitudinal movement
- Lateral (side-to-side) movement

Directional anchors are used primarily in pipe racks, however they can be used in other locations as deemed necessary by the **stress engineer**.



Pipe rack showing stops

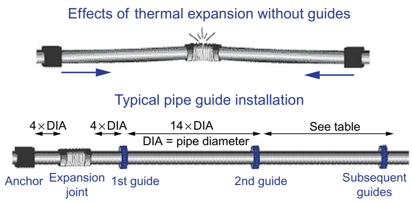


Graphic of Pipe Stop

17.3 GUIDES AND RESTRAINTS

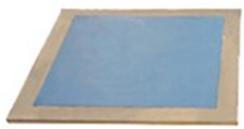
GUIDES

Guides are used to direct a pipe (guide it) in one direction—linear direction of the pipe—guiding it in the direction away from the anchor point.

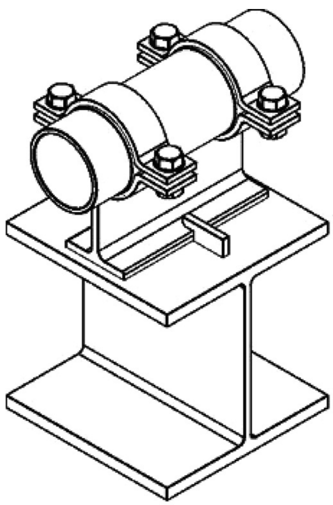


Result of an unguided line

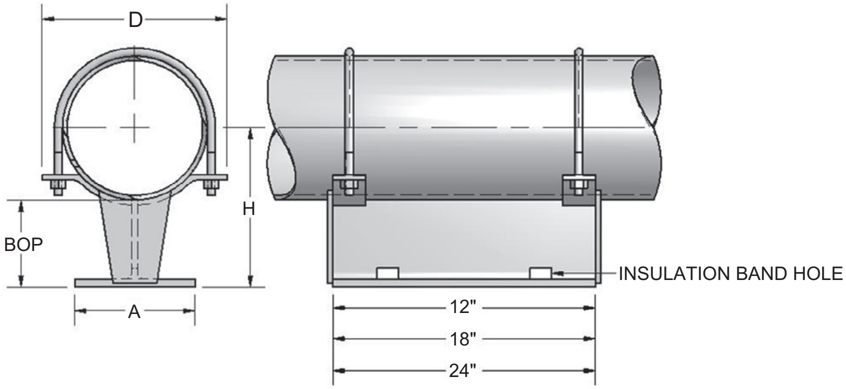
Guided pipe shoe

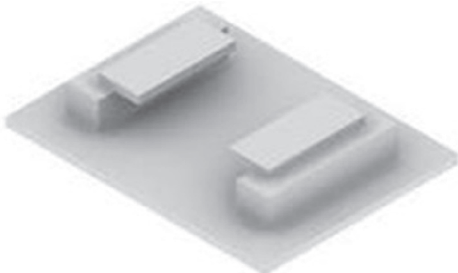


Slide plate



Clamped guided pipe



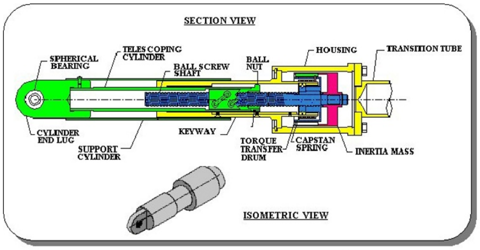


RESTRAINTS

Snubbers act as a **restraint**. They allow movement in tension and compression under normal conditions. They are restraining devices used to control the movement of pipe and equipment during abnormal dynamic conditions such as earthquakes, turbine trips, safety/relief valve discharge, and rapid valve closure. They are activated when an impulse event occurs. The design of a snubber allows free thermal movement of a component during normal operation conditions, but restrains the component in abnormal conditions. **Snubbers** are available as either a mechanical or a hydraulic unit.

Selection of which type to use will be decided by the stress engineer, based on the pipe line forces and location practicalities.

A mechanical **snubber** uses gears and springs to produce the restraint force when activated.

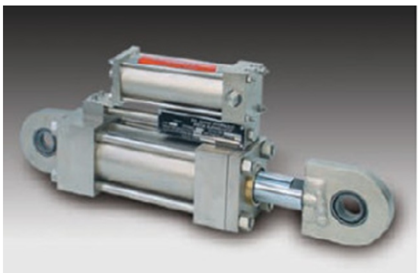


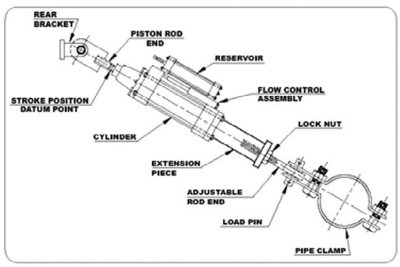
Graphic of a mechanical snubber

Photo of snubber in a plant

SNUBBERS

Hydraulic **snubbers** have a piston which is relatively unconstrained in motion at low displacement rates. At high displacement rates the piston “locks up” and acts as a rigid restraint.





SWAY BRACES

These use springs to provide a restraint force, and **allows** movement in tension and compression.

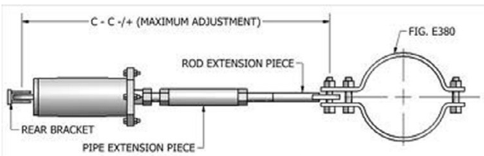
Sway Braces have **variable spring rates.**

Sway braces

SWAY STRUTS

These are a rigid support and they **do not allow** movement in tension and compression.

A **sway strut** allows for **rotational movement.**



Graphic of a sway strut

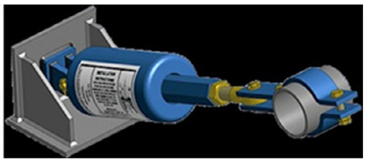
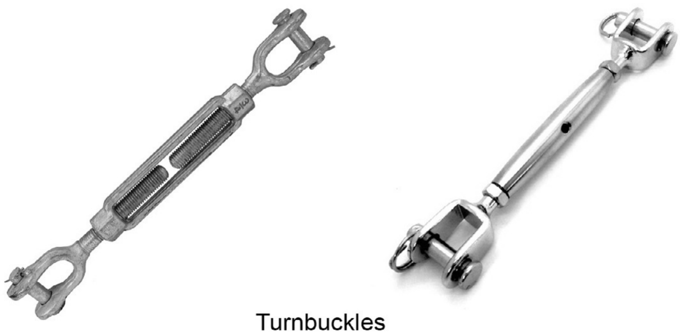


Photo of a sway strut

TURNBUCKLES

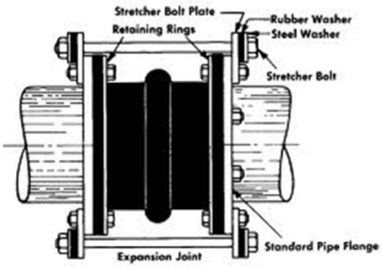
Turnbuckles are a manually adjusted turn screw activated by turning a buckle on the center of the unit. Used for braces and rigid supports, for example, on pipe racks and on vertical lines to restrain movement.



Turnbuckles

17.4 EXPANSION JOINTS

Expansion Joints are a bellows type device. **Expansion joints** are used to absorb thermal expansion. They can also be used to absorb contraction in cryogenic lines and to reduce vibration in piping systems. Materials of construction for the bellows can be stainless steel or rubber or even a composite material. They are necessary in systems that convey high-temperature substances such as steam or exhaust gases, or to absorb movement and vibration.



Graphic of an Expansion Joint (Bellows)

photo of an Expansion Joint (Bellows)

The most common type of bellows is made of metal (most commonly stainless steel), plastic (such as PTFE), fabric (such as glass fiber), or an elastomer such as rubber.

A bellows is made up of a series of convolutions, with the shape of the convolution designed to withstand the internal pressures of the pipe, but flexible enough to accept axial, lateral, and angular deflections. Expansion joints are also designed for other criteria, such as noise absorption, antivibration, earthquake movement, and building settlement.

17.5 SPRING HANGERS

There are two types of spring support—**variable** and **constant**.

VARIABLE SUPPORT

In a variable support the force acts on the spring and hence the reactive force varies during the pipe travel, while the moment about the line of action is zero. In contrast, in a constant support, the fixed applied load remains uniform throughout its travel but the moment around a pivot point varies.

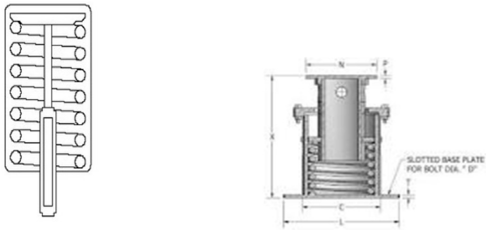
A **variable spring support** is essentially a spring, or series of springs, in a container. When the installed load "*w*" is applied, the spring is compressed through the distance W/k (where k is the spring rate) such that the reactive force exerted by the spring is also "*w*" under the equilibrium condition. As the pipe moves due to thermal expansion, it produces a deflection ($\triangle L$), causing a differential load ($\triangle W = k \cdot \triangle L$), to act on the spring(s). Depending on the direction of the movement, the change in load ($\triangle W$) will either add to or subtract from our installed load "*w*" to reach our final operating load ($w1$). In order to minimize the stress variations, the differential load ($\triangle W$) for a given variable spring support is limited to a maximum of 25% of the operating load ($w1$).

VARIABLE SPRING HANGERS

Variable spring hangers are used to support piping subject to vertical movement where constant supports are not required. The inherent characteristic of a variable spring is such that its supporting force varies with spring deflection and spring scale.

Vertical expansion of the piping causes a corresponding extension or compression of the spring and will cause a change in the actual supporting effect of the hanger. The variation in supporting force is equal to the product of the amount of vertical expansion and the spring scale of the hanger. Since the pipe weight is the same during any condition, cold, or operating, the variation in supporting force results in pipe weight transfer to equipment and adjacent hangers and consequently additional stresses in the piping system. When variable spring hangers are used, the effect of this variation must be considered.

Variable Spring Hanger



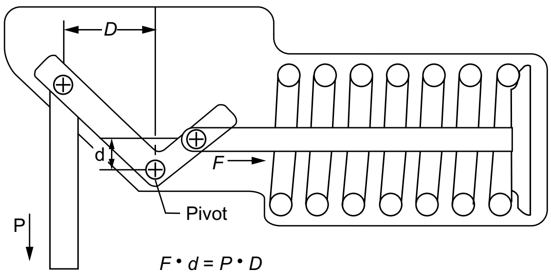
Graphics of Variable Spring Hangers

Photo of Variable Spring Hangers

CONSTANT SUPPORT

A constant support is a device comprised of a spring or series of springs and an integral cam mechanism. The external load of a constant support is fixed while its moment about the fixed pivot point varies during its travel (because the moment arm length changes). Constant spring support in order to maintain an equilibrium condition, the external force moment is balanced by the internal moment produced due to the spring's compression or decompression about the pivot during the displacement of the pipe.

Constant support

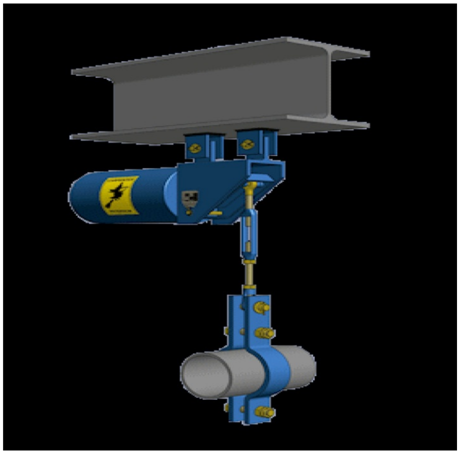


At each travel location of the applied load, the moment caused by the external load is balanced by the counter moment produced by the (compressed/decompressed) spring force with the appropriate moment arm. Typically, the variation of the active and reactive forces is very small (with a maximum deviation of 6%) and can be taken as a constant force while moving either upward or downward.

CONSTANT SUPPORT HANGERS

This provides constant supporting force for piping throughout its full range of vertical expansion and contraction. This is accomplished through the use of a helical-coil spring working in conjunction with a bell crank lever in such a way that the spring force times its distance to the lever pivot is always equal to the pipe load times its distance to the lever pivot.

Constant support hangers are used where it is desirable to prevent pipe weight load transfer to connected equipment or adjacent hangers. They are used where vertical movement should not be restricted by rigid hangers and where variable spring hangers cannot be used due to the high deviation between installation load and operating load.



3D graphic of constant support hanger

Constant support hangers are also used where no great supporting load deviations are allowed in order to avoid additional loadings of the component connections or critical pipe components; consequently, they are used generally for the support of critical piping systems.

SELECTION OF SPRING HANGERS

Criteria needed to select a spring hanger are:

- Permissible force variation between cold load (installation load) position to hot load (operating load)—this is limited to 25% of the operating load.

- Maximum working travel—should not exceed 50 mm, to avoid using extra long springs which can cause instability.
- Spring rate—which is divided into five travel ranges, to choose the spring size (refer to manufacturers charts for travel range versus type number).
- Design type—selection depends upon the respective support configuration or the installation situation.
- Once the pipe load has been established along with the amount of travel required and the installation requirements for the specific location have been ascertained, the correct type of spring hanger can be established, and from the manufacturers charts the correct size of spring can be ordered, along with the correct fittings to suit the particular installation.

CHAPTER

Pipe sizing and pressure drop calculations

18

18.1 THEORY OF FLOW IN PIPES

A fluid is a substance that can sustain no static **shear stress.** As such, a fluid will take the shape of its container. **Shear stress** will develop as the fluid flows. Some fluids flow more readily than others and the property that describes the ease of flow is **Viscosity.**

Viscosity expresses the readiness with which a fluid flows when it is acted upon by an external force. The **coefficient of absolute viscosity,** or simply, put "the **absolute viscosity of a fluid,**" is the measure of its resistance to internal deformation of **shear.**

To make this clearer, let us look at the following experiment:

If you put a thin layer of liquid between two parallel plates and move one plate at a velocity **U** and keep the other plate fixed, the width of the plates is large compared to the space between them. The force to move the plate divided by the area is the **Shear Stress.**

The **viscosity** of the fluid is the ratio of this force to the shear rate (the shear rate in this example is the velocity divided by the plate spacing). Fluids with a low viscosity require less force to keep the plate in motion at the constant speed **U** than fluids with a high viscosity. This experiment can be carried out at many different speeds or plate spacings, so that a curve of shear rate versus shear stress can be found.

If the curve (after the results in the experiments) is found to be a straight line, which passes through the origin, then the fluid is referred to as a "**Newtonian Fluid**."

If the curve does not pass through the origin, then we say that the fluid is "**Non-Newtonian**"

For Newtonian fluids, the viscosity is a function of temperature.

The **viscosity** of a gas will **increase** with temperature at low pressures.

The **viscosity** of a liquid will **decrease** as the temperature is increased.

Although the viscosity of gases can be estimated at low pressures using equations derived from the Kinetic theory of gases, the viscosity of liquids must be measured.

Solutions to problems involving flow of fluids can be started by examining the **equations** of **change;** these consist of:

*The reader is advised to review the Crane Company booklet "Flow of Fluids" for the Appendix section of this book.

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00018-7

- Conservation of mass
- Conservation of linear and angular momentum
- Conservation of energy

The differential forms of these equations are obtained from a balance about a small element of liquid in the form:

$$\text{(Rate of accumulation)} = \text{(net rate in by molecular motion)} + \text{(net rate in by fluid motion)} + \text{generation} + \text{other inputs}$$

DYNAMIC (ABSOLUTE VISCOSITY)

The SI (System International) unit of **dynamic viscosity** is the "**Pascal second**" **(Pa s)** also expressed as "**Newton second per square meter**" **(N s/m^2)** or as the **kilogram per meter second kg/(m s).**

In the CGS (centimeter, gram second) metric unit, the unit of absolute viscosity is the "**poise**" which has the units of dyne seconds per square meter or of grams per centimeter second.

There is some confusion existing in the industry concerning the correct units to use to express viscosity.

The submultiple centipoise **(cP), 10^{-2} poise, is** the unit most commonly used at present to express **dynamic viscosity.**

The relationship between Pascal second and centipoise is

$$1\,\text{Pa s} = 1\,\text{N s/m}^2 = 1\,\text{kg/(m s)} = 10^3\,\text{cP}$$
$$1\,\text{cP} = 10^{-3}\,\text{Pa s}$$

In the following calculations, the symbol **μ** is used for viscosity measured in centipoise and μ' for viscosity measured in Pascal second units.

The viscosity of water at a temperature of 20°C is almost 1 cP (actually 1.002 cP) or 0.001 Pa s.

Kinematic viscosity—It is the ratio of the dynamic viscosity to the density.

Metric (SI) units of kinematic viscosity is the meter squared per second (m^2/s).

In the CGS units, the stokes (St) dimensions, centimeter's squared per second and the centistoke (cSt), 10^{-2} stokes is the submultiple commonly used

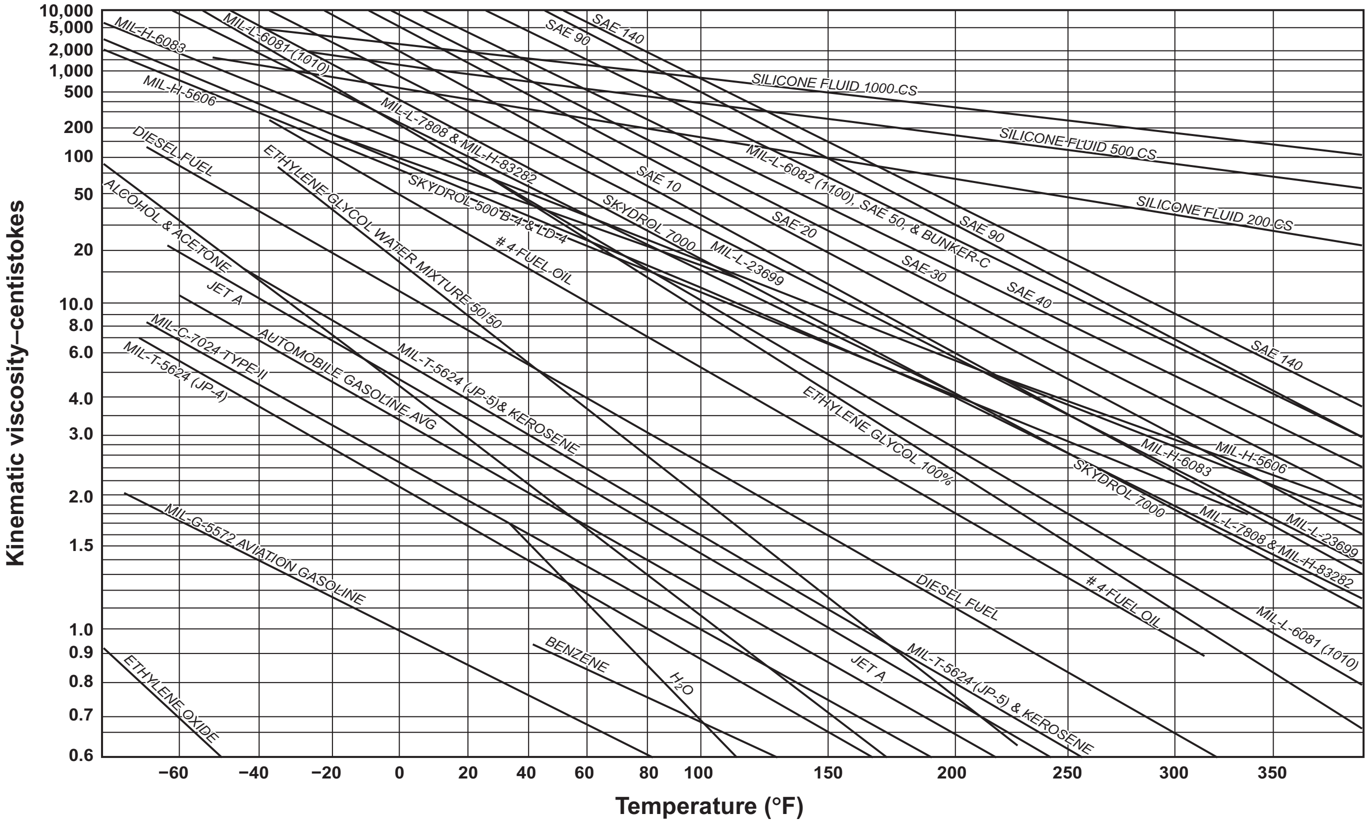
$$1\,\text{m}^2/\text{s} = 10^6\,\text{cSt}$$
$$1\,\text{cSt} = 10^{-6}\,\text{m}^2/\text{s}$$
$$V\,\text{(centistokes)} = \mu\,\text{(centipoise)}$$
$$\rho'\,\text{(grams per cubic cm)}$$

Various types of tube viscometers are in use, resulting in empirical scales:

- Saybolt Universal
- Saybolt Furol (for very viscous liquids)
- Redwood No. 1 and No. 2
- Engler

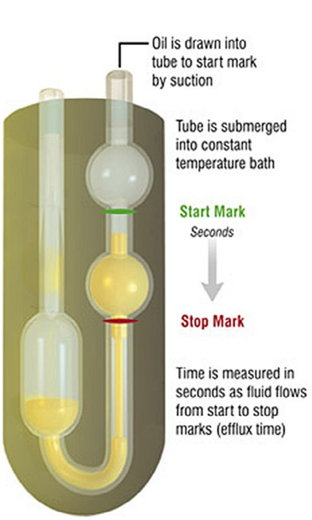
The ASTM standard viscosity temperature chart for liquid petroleum products is used to determine the Saybolt Universal viscosity of a petroleum product at any temperature when the viscosities at two different temperatures are known.

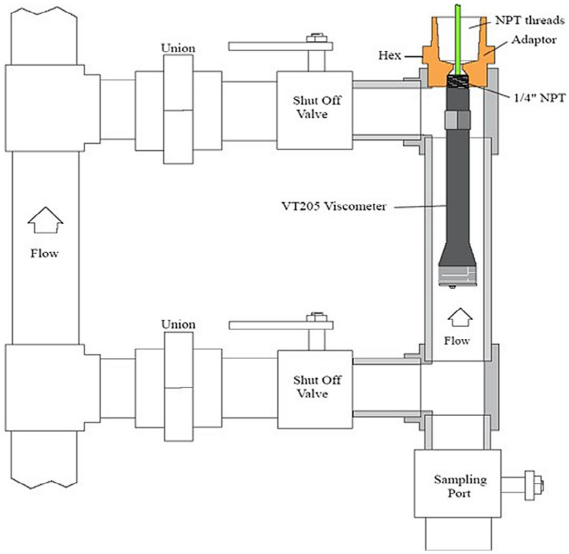
Viscosities of typical fluids vs. temperature



A simple instrument, called a “**tube viscometer or viscometer,**” **can** be used for the measurement of the kinematic viscosity of oils and of other viscous liquids.

A viscometer works by measuring the time taken for a small volume of liquid to flow through an orifice, this measurement is expressed in terms of seconds:





Hydrometers can be used to measure the specific gravity of a liquid. The two hydrometer scales in common use are:

- **API** scale—it is used for Oils
- **Baumé**—This scale has two scales in use:
  - one for liquids heavier than water
  - one for liquids lighter than water

DENSITY, SPECIFIC VOLUME, AND SPECIFIC GRAVITY

The density of a substance is its mass per unit volume.

The SI unit of density is the kilogram per cubic meter (kg/m^3).

The symbol designation used is ρ (Rho).

The SI unit used for specific volume is V, which is the reciprocal of density, expressed in **cubic meter per kilogram (m^3/kg).**

$$V = \frac{1}{\rho}, \quad \rho = \frac{1}{V}$$

DENSITY OF LIQUID WATER

Temp (°C)	Density (kg/m^3)
+100	958.4
+80	971.8
+60	983.2
+40	992.2
+30	995.6502
+25	997.0479
+22	997.7735
+20	998.2071
+15	999.1026
+10	999.7026
+4	999.9720
0	999.8395
−10	998.117
−20	993.547
−30	983.854

Variations in density, pressure, and specific volume all have an effect on a liquid; however, unless very high pressures are being considered, the effect of pressure on the density of liquids is not of practical importance for flow problems.

Densities of gases and vapors, however, are greatly altered by pressure. Density can be computed by the following formula:

$$\rho = \frac{P'}{RT} \quad \text{or} \quad \frac{10^5 P'}{RT}$$

Specific Gravity (relative density) is a relative measure of density.

Since **pressure** has an insignificant effect upon the **density** of liquids, **temperature** is the only condition that must be considered in designating the basis for specific gravity.

The specific gravity of a liquid is the ratio of its density at a specified temperature to that of water at some standard temperature.

Usually the temperatures are the same; for example, 60°F/60°F (15.6°C/15.6°C) is commonly used:

***S* = *ρ* (any liquid at specified temperature)**
***ρ* water at 60°F (15.6°C)**

Relationship between **hydrometer** scales and **specific gravity is**

For oils: $S\left(60^{\circ}\mathrm{F}/60^{\circ}\mathrm{F}\right) = \dfrac{141.5}{131.5 + \text{deg.API}}$

$$\text{For liquids lighter than water: } S\left(60^{\circ}\text{F}/60^{\circ}\text{F}\right) = \frac{140}{130 = \text{deg.Baumé}}$$

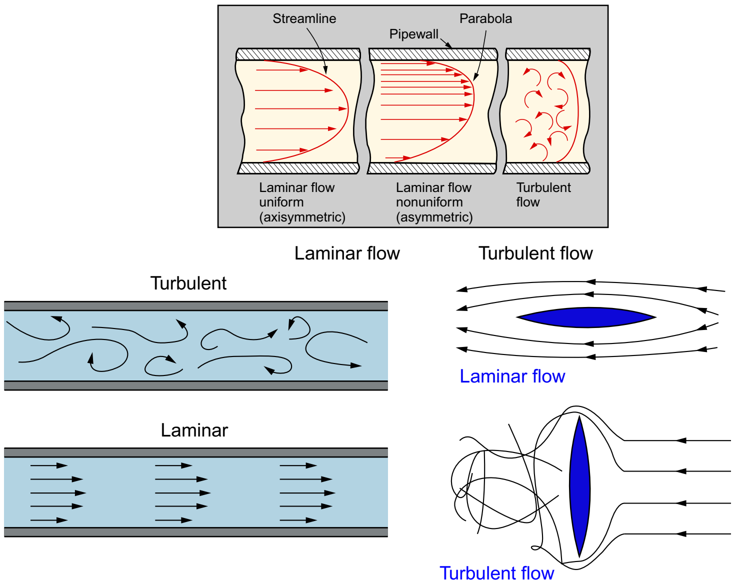
$$\text{For liquids heavier than water: } S\left(60^{\circ}\text{F}/60^{\circ}\text{F}\right) = \frac{145}{145 - \text{deg.Baumé}}$$

The **specific gravity** of gases is defined as the ratio of the **molecular weight** of the gas to that of air, and as the ratio of the individual gas constant of air to that of gas:

$$\text{Sg} = \frac{R(\text{air})}{R(\text{gas})} = \frac{M(\text{gas})}{M(\text{air})}$$

NATURE OF FLOW IN PIPE

Turbulent and laminar flow



Turbulent and laminar flow

TURBULENT AND LAMINAR FLOW

If the average velocity in the pipe is small, then the flow will be relatively smooth, and this is called "**Laminar Flow.**"

As the velocity is gradually increased, the fluid particles will start to waver and break into a diffused pattern (as shown on the previous slide). The velocity at which this occurs is called "**critical velocity**" **(which is the start of turbulence).**

At velocities higher than "**critical,**" the liquid becomes **turbulent.**

At higher than critical velocities, the type of fluid is called "**Turbulent Flow.**"

In **Laminar Flow** (also known as **viscous** or **streamline flow**), the flow characteristic is for smooth, gliding of cylindrical fluid particle layers passing one another in an orderly fashion.

In **Turbulent Flow,** there is a random motion of the fluid particles in directions transverse to the direction of the main flow.

The **velocity** distribution in **turbulent flow** is more uniform across the pipe diameter than in **laminar flow;** even though turbulence exists throughout the greater portion of the pipe diameter, there is always a thin layer of fluid at the pipe wall; this is known as the "**boundary layer**" or "**laminar sublayer**", and is moving in laminar **flow.**

Mean flow velocity—It refers to the mean or average velocity at a given cross section.

It is determined by the equation for steady-state flow:

$$V = \frac{q}{A} = \frac{w}{A\rho} = \frac{wV}{A}$$

Reasonable **velocities** for the flow of water through pipes:

Service Condition	Reasonable Velocity
Boiler feed	2.4–4.6 m/s
Pump suction and drain lines	1.2–2.1 m/s
General service	1.2–3.0 m/s
City water	up to 2.1 m/s

Reasonable **velocities** for flow of steam through pipe:

Steam Condition	Pressure (P) bar	Service	Reasonable Velocity (*V*) m/min
Saturated	0–1.7	Heating short lines	1200–1800
	1.7 and up	Powerhouse equipment process piping, etc.	1800–3000
Superheated	14 and up	Boilers, turbine leads	2000–6000

REYNOLDS NUMBER

Osborne Reynolds demonstrated that the flow in pipes could be either **laminar** or **turbulent**, depending on the diameter, the density, viscosity, and the velocity of flow of the flowing fluid.

Reynolds came up with a numerical value of a dimensionless combination of diameter, density, viscosity, and flow velocity.

This numerical value is what we refer to as the "**Reynolds Number**."

The **Reynolds number** is the ratio of dynamic forces of mass flow to the shear stress due to viscosity.

The equation to determine the Reynolds number is

$$R_e = \frac{\rho V L}{\mu}$$

where ρ is the density of the fluid, V is the velocity of the fluid, ρ is the density of fluid, μ is the viscosity of fluid, and L is the length or diameter of the fluid.

When a conduit of noncircular cross section is encountered, to calculate the Reynolds number the equivalent diameter (four times the hydraulic radius is used)

$$R_H = \frac{\text{cross-sectional flow area}}{\text{wetted perimeter}}$$

HYDRAULIC RADIUS

The previous equation applies to a conduit that is not flowing full, or is oval, square, or rectangular

In cases where the conduit is narrow, annular, or has an elongated length, the hydraulic radius is approximately equal to one-half of the width of the passage.

Quantity of flow can be calculated using the following equation:

$$Q = 0.2087 d^2 \sqrt{\frac{h_L D}{fL}}$$

where h_L is the loss of static pressure head due to fluid flow (meters of fluid), f is the friction factor, L is the length of pipe (m), D is the internal dia of pipe (m), and d^2 is the internal dia of pipe (mm).

REYNOLDS NUMBER

The Reynolds number can be used to determine if flow is laminar, transient, or turbulent. The flow is

- **laminar** when $\boldsymbol{Re < 2300}$
- **transient** when $\boldsymbol{2300 < Re < 4000}$
- **turbulent** when $\boldsymbol{Re > 4000}$

Example: Calculating the Reynolds number

Find the Reynolds number if a fluid of viscosity 0.4 Ns/m^2 and relative density of 900 kg/m^3 through a 20-mm pipe with a velocity of 2.5 m/s?

Solution

Viscosity of fluid $\mu = 0.4$ N s/m^2,

Density of fluid $\rho = 900$ kg/m^3,

Diameter of the fluid $L = 20 \times 10^{-3}$ m

The **Reynolds formula** is given by

$$R_e = \frac{\rho V L}{\mu}$$
$$= \frac{900 \times 2.5 \times 20 \times 10^{-3}}{0.4}$$
$$= 112.5$$

We can see that the value of the **Reynolds number** is less than 2000, so the flow of liquid is laminar.

EQUATIONS FOR FLOW OF FLUIDS

Bernoulli's theorem

Daniel Bernoulli, the Dutch-Swiss mathematician, published his book *Hydrodynamica* in 1738. In this book, he derived a theorem which expresses the application of the law of conservation of energy to the flow of fluids in a conduit.

Bernoulli's principle states that for an **inviscid** flow (a flow of an ideal fluid that is assumed to have no viscosity), an increase in the speed of the fluid occurs simultaneously with a decrease in pressure or a decrease in the fluid's potential energy.

Stated **simply, "As the speed of a moving fluid (liquid or gas) increases, the pressure within the fluid decreases.**"

Bernoulli's principle can be applied to various types of fluid flow, resulting in what is loosely denoted as **Bernoulli's equation.**

There are different forms of the Bernoulli equation for different types of flow.

The simple form of Bernoulli's principle is valid for incompressible flows (e.g., most liquid flows) and also for compressible flows (e.g., gases) moving at low Mach numbers.

Bernoulli's principle can be derived from the principle of conservation of energy. This states that, in a steady flow, the sum of all forms of mechanical energy in a fluid along a streamline is the same at all points on that streamline. This requires that the sum of kinetic energy and potential energy remains constant. If the fluid is flowing out of a reservoir, the sum of all forms of energy is the same on all streamlines because in a reservoir the energy per unit mass (the sum of pressure and gravitational potential $\rho g h$) is the same everywhere.

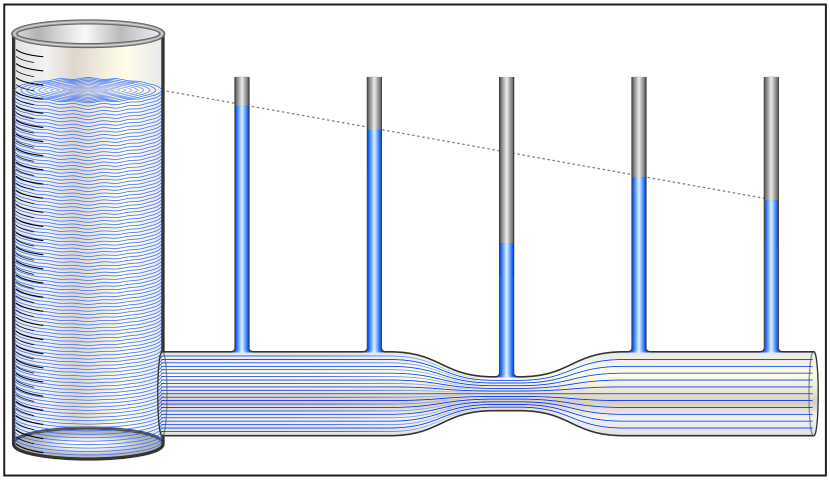
Fluid particles are subject only to pressure and their own weight.

If a fluid is flowing horizontally and along a section of a streamline, where the speed increases it can only be because the fluid on that section has moved from a region of higher pressure to a region of lower pressure; and if its speed decreases, it can only be because it has moved from a region of lower pressure to a region of higher pressure.

Consequently, within a fluid flowing horizontally, the highest speed occurs where the pressure is lowest, and the lowest speed occurs where the pressure is highest.

The total energy at any particular point above some arbitrary horizontal datum plane is equal to the sum of the elevation head, the pressure head, and the velocity head:

$$Z+\frac{P}{\rho g_{\mathrm{n}}}+\frac{v^2}{2g_{\mathrm{n}}}=H$$



If friction losses are neglected and no energy is added to or taken from a piping system, the total head H in the above equation will be constant for any point in the fluid.

In practice, losses or energy increases or decreases are encountered and must be included in Bernoulli's equation.

An energy balance can be written for two points in a fluid (see illustration in figure).

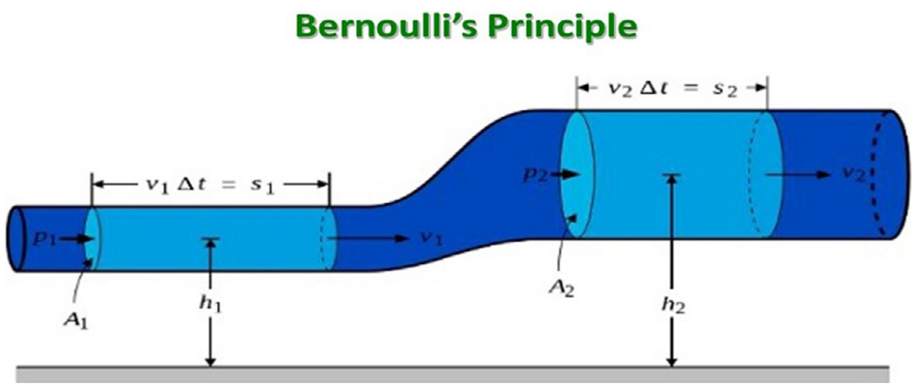
The friction loss from point 1 to point 2 *(h_L)* is referred to as the head loss in meters of fluid.

The friction loss from point 1 to point 2 *(h_L)* is referred to as the head loss in meters of fluid.

The equation is written as follows:

$$Z_1+\frac{P_1}{\rho_1 g_n}+\frac{v_1^2}{2g_n}=Z_2+\frac{P_2}{\rho_2 g_n}+\frac{v_2^2}{2g_n}+h_L+h_L$$

All the practical formulas for the flow of fluids are derived from Bernoulli's theorem, with modifications to account for losses due to friction.



MEASUREMENT OF PRESSURE

Barometric pressure—It is the level of atmospheric pressure above a perfect vacuum.

Standard atmospheric pressure—It is 1.013 bar (14.6959 lbf/in^2) or 760 mm of mercury.

Gauge pressure—It is measured above atmospheric pressure.

Absolute pressure—It refers to perfect vacuum as a base.

Vacuum—It is the depression of pressure below atmospheric level.

Vacuum conditions can be expressed by referring to absolute **pressure** in terms of height of a column of mercury or of water; they can be indicated as

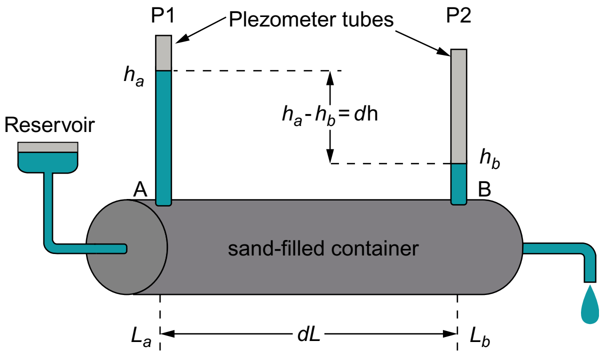
- mm of mercury
- micrometer of mercury (micron) of mercury
- inch of water or inch of mercury

Flow in a pipe is accompanied by the friction of fluid particles rubbing against one another; as a result, a loss of energy results, and this results in a pressure drop in the direction of flow.

Darcy's formula

Henry Darcy as Chief Engineer for the department Cote—d'Or in France was promoted to Chief Director for water and pavements in Paris. While in this position, he was able to concentrate on his research into hydraulics. He established a formula for laminar and turbulent flow of liquids in pipes.

The diagram below shows how there is a pressure drop between P1 and P2.



Horizontal pipe demonstrating Darcy's experiment

The **Darcy** friction factor formulae are equations—based on experimental data and theory—for the Darcy friction factor. The Darcy friction factor is a dimensionless quantity used in the Darcy-Weisbach equation for the description of friction losses in pipe flow as well as open channel flow.

It is also known as the Darcy-Weisbach friction factor or Moody friction factor and is four times larger than the Fanning friction factor.

The general equation for pressure drop, known as Darcy's formula and expressed in Newtons per square meters of fluid, is

$$\Delta P = \frac{\rho f L v^2}{2D} \tag{1}$$

The Darcy friction factor for laminar flow (Reynolds number less than 2100) is given by the following formula:

$$f = \frac{64}{\mathrm{Re}} = \frac{64\mu'}{Dv\rho} = \frac{64\mu}{dv\rho}$$

where f is the Darcy friction factor and Re is the Reynolds number.

- If this quantity is substituted into Eq. (1), the pressure drop in Newtons per square meter is

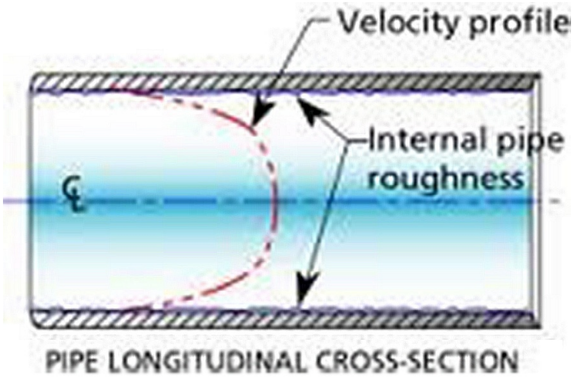
$$\Delta P = 32{,}000\,\frac{\mu L v}{d^2} \text{ (This is Poiseuille's law for laminar flow)}$$

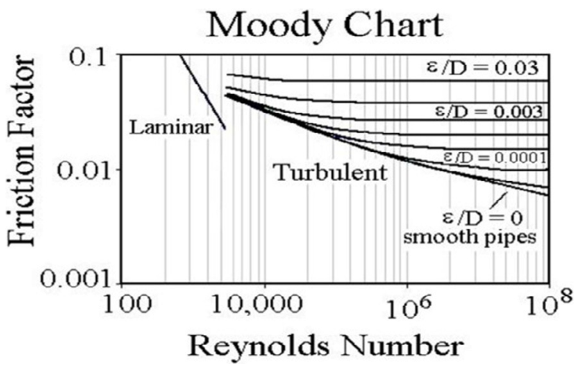
When the $Re > 4000$ (that is the Reynolds number is greater than 4000), the flow is regarded as **turbulent.**

The **friction factor** depends not only on the Reynolds number but also on the relative roughness.

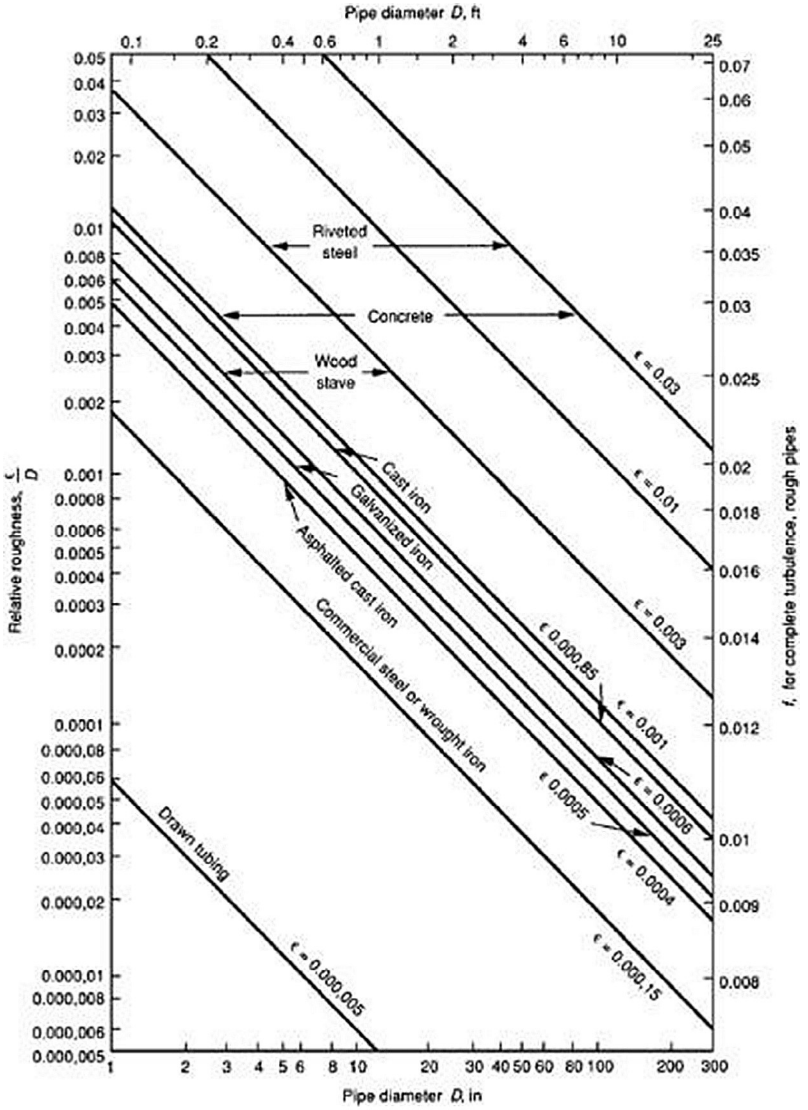
(ε/d)**, that is,** Roughness of pipe walls (ε) compared to diameter of the pipe.

The **friction factor** for smooth pipes (e.g., brass tubing) decreases more rapidly with the increasing **Reynolds number** than for the pipe with comparatively rough walls.





The internal surface of a pipe is independent of the diameter. The friction factor caused by the internal wall roughness has a greater effect on the friction factor in small pipe sizes. This means that a small diameter pipe will approach its rough condition and have a higher friction factor than a larger diameter pipe of the same material.



Relative Roughness in Pipes Chart

$$\text{Laminar flow}: f = \frac{64}{Re}$$

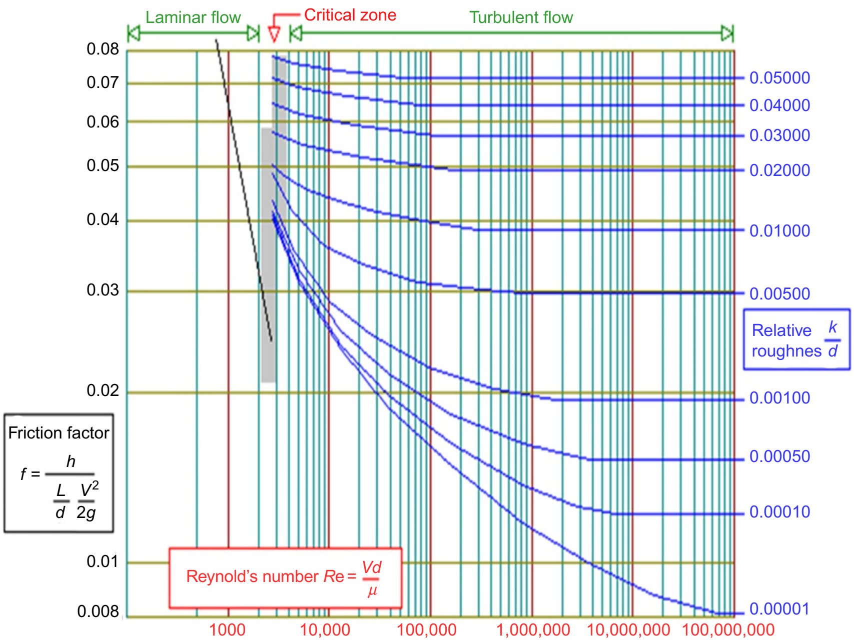
$$\text{Smooth pipe turbulent flow}: f = \frac{0.316}{Re^{1/4}}$$

$$\text{Completely turbulent flow}: f = \left[1.14 + 2\log_{10}\left(\frac{D}{\varepsilon}\right)\right]^{-2}$$

$$\text{Transition region}: f = \left\{-2\log_{10}\left[\frac{(\varepsilon/D)}{3.7} + \frac{2.51}{Re(f^{1/2})}\right]\right\}^{2}$$

Pipe Material	**Roughness, ε feet**
Drawn brass or copper	0.000005
PVC pipe	0.000005
Commercial steel	0.000150
Wrought iron	0.000150
Asphalted cast iron	0.000400
Galvanized iron	0.000500
Cast iron	0.000850
Concrete	0.001–0.01

RELATIVE ROUGHNESS OF PIPE, MATERIALS, AND FRICTION FACTOR FOR COMPLETE TURBULENCE



Friction factors for commercial pipe

The charts on the previous pages show friction data that were formulated by Professor L.F. Moody, who improved on already well-established Pigott and Kemler friction factor diagrams, by incorporating the more up-to-date developments by engineers and scientists.

Friction loss in pipes is affected by changes in diameter and its internal roughness.

Based on a given flow rate and a fixed friction factor, the pressure drop per meter of pipe varies with the fifth power of its diameter, for example:

- a 2% reduction of diameter causes an 11% increase in pressure drop
- a 5% reduction of diameter causes an 29% increase in pressure drop

Roughness increases due to corrosion, incrustation, and use.

Owing to the age and use of the pipe, the interior of a pipe becomes encrusted with scale, rust, dirt, tubercules, and other foreign matter; so it is important to make allowance for any future expected diameter changes.

An example of this is a 4″ galvanized steel pipe that had its roughness doubled, and its friction factor increased 20% after 3 years of use.

18.2 PRESSURE DROP

To be able to calculate the pressure drop of a compressible fluid flowing through a pipe, a knowledge of the relationship between the pressure and specific volume is required.

Two extremes that are usually considered are:

Adiabatic flow $\left(P' V_a{}^{Y} = \text{constant}\right)$

Adiabatic flow is usually assumed as a short insulated pipe, where no heat is transferred to or from the pipe, except for the small amount of heat that is generated by friction and is added to the flow.

Isothermal flow $(P' V_a = \text{constant})$

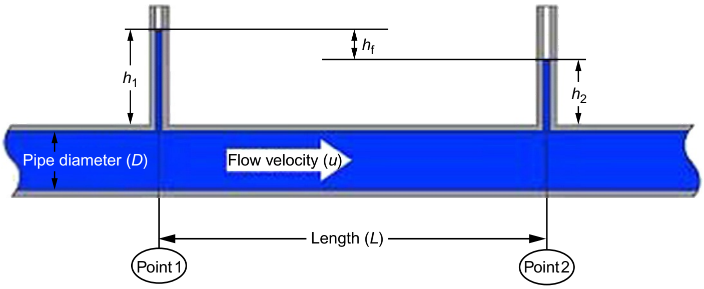
Isothermal flow is a flow that is assumed to be at a constant temperature.

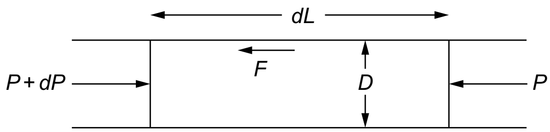
An outstanding case of **isothermal flow** occurs in natural gas pipelines where two engineers Dodge and Thompson showed that the gas flow in an insulated pipe is closely approximated by **isothermal flow** for high pressures.

The relationship between pressure and volume is called "**Polytropic flow**," designated by the formula $(P' V_a^n = \text{constant})$.

The **Density** of gases and vapors changes with pressure.

If the pressure drops between P_1 and P_2 as shown in the diagram below is great, the density and velocity will change appreciably.





COMPRESSIBLE FLUIDS

Compressible fluids such as Air, Steam, etc. have some restrictions that must be observed when applying the **Darcy formula.**

For a calculated **Pressure drop ($P_1 - P_2$)** of less than 10% of the inlet pressure P_1 reasonable accuracy can be obtained if the specific volume used in the formula is based on either the upstream or downstream conditions, whichever is known.

For a calculated **Pressure drop ($P_1 - P_2$)** of greater than 10%, but less than 40% of the inlet pressure **P_1 the Darcy equation** may be used with reasonable accuracy, by using a specific volume based on the average upstream and downstream conditions; otherwise, the methods mentioned next might be used.

For pressure drops in long pipelines the methods next may also be used.

Flow of gases in long pipes closely approximates **isothermal** conditions.

Pressure drop in these lines is often large relative to the **inlet pressure,** so the solution of this type of problem falls outside of the **Darcy equation**.

An accurate way of determining the flow characteristics that fall within this category is by using the following equation:

$$w^2 = \left[\frac{144gA^2}{V_1'\left(\frac{fL}{D} + 2\log_e \frac{P_1}{P_2}\right)}\right] \times \left[\frac{(P_1)^2 - (P_2)^2}{P_1}\right].$$

Compressible flow in gas pipeline

The formula for discharge in a horizontal pipe may be calculated by using the following equation:

$$\omega^2 = \left[\frac{144gDA^2}{\overline{V}_1 fL}\right]\left[\frac{P_1^2 - P_2^2}{P_1}\right].$$

Since gas flow is expressed in terms of cubic meters per hour, the formula is rewritten as follows:

$$q_k = 1.361 \cdot 10^{-7}\sqrt{\left[\frac{p_1^2 - p_2^2}{fL_m TS_g}\right]}d^s$$

Other formulas

Weymouth formula for compressible flow in long pipelines.

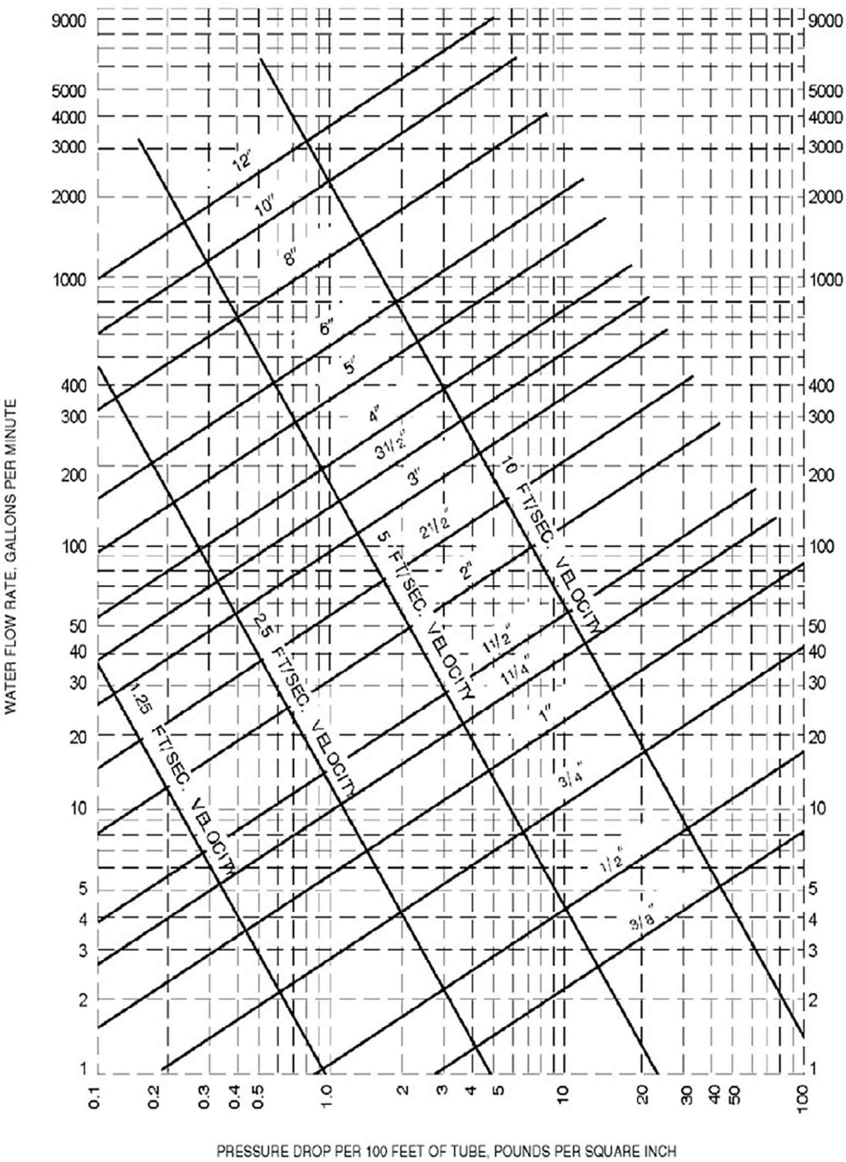
$$q_k = 2.61 \cdot 10^{-8} d^{2.667}\sqrt{\left[\frac{p_1^2 - p_2^2}{S_g L_m}\right]\frac{288}{T}}$$

Panhandle formula for natural gas pipelines is Panhandle formula.

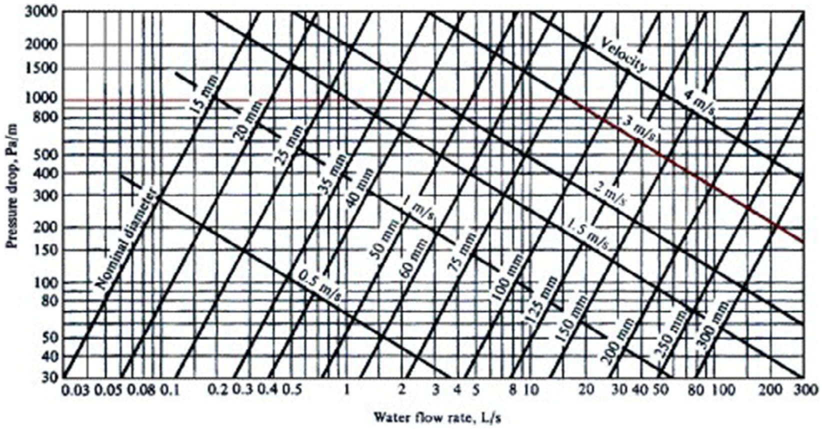
$$q_k = 2.044 \cdot 10^{-8} Ed^{2.6180}\sqrt{\left[\frac{p_1^2 - p_2^2}{L_m}\right]}^{0.5894}$$

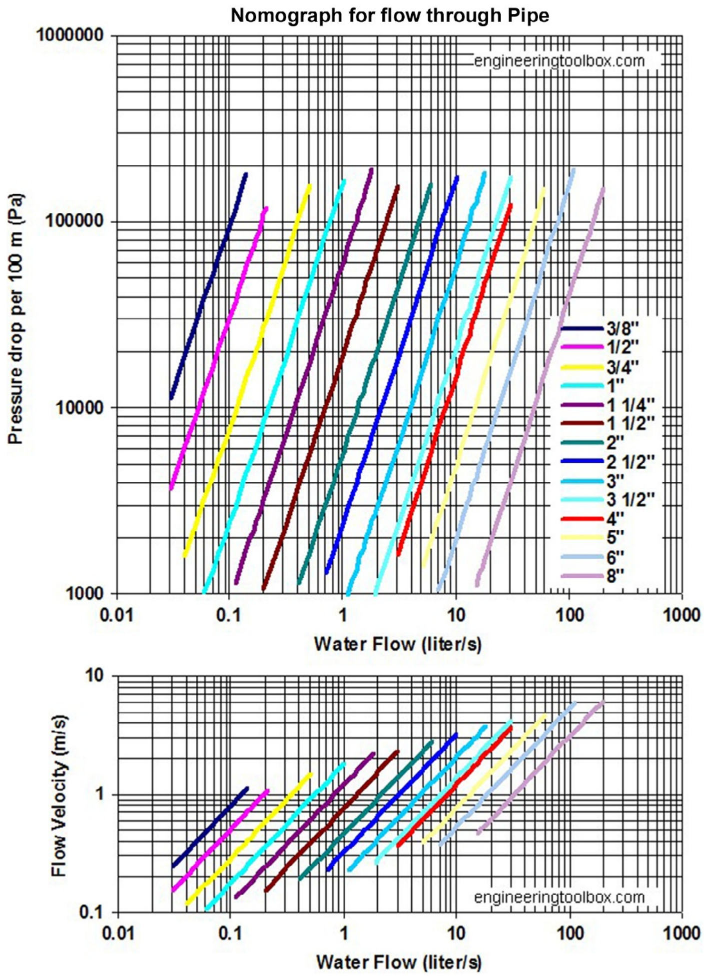
where q_h is the volumetric flow rate [m^3/h], p is the pressure [Pa], L_m is the pipe length [km], and d is the internal pipe diameter.

18.3 FORMULAS AND NOMOGRAPHS FOR FLOW THROUGH VALVES AND FITTINGS

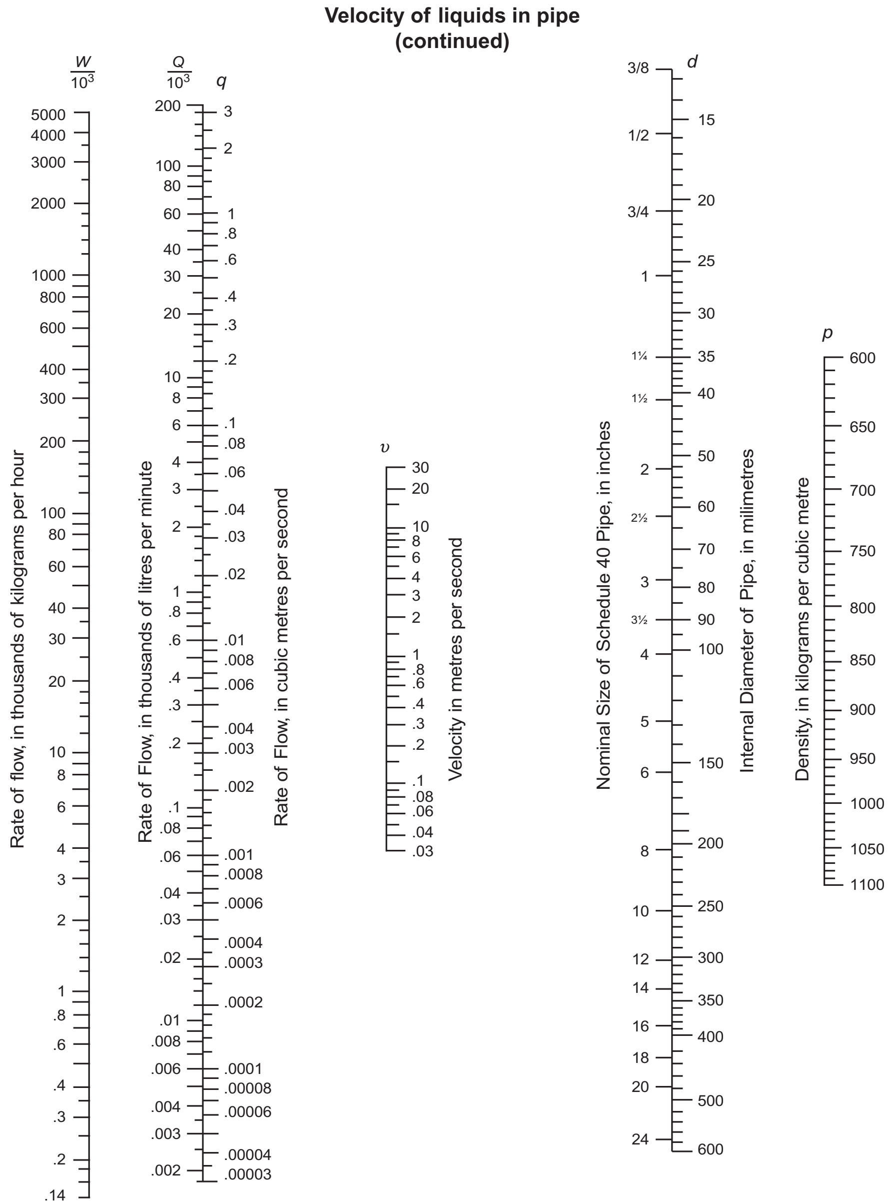


Note: Fluid velocities in excess of 5 to 8 feet/second are not usually recommended.

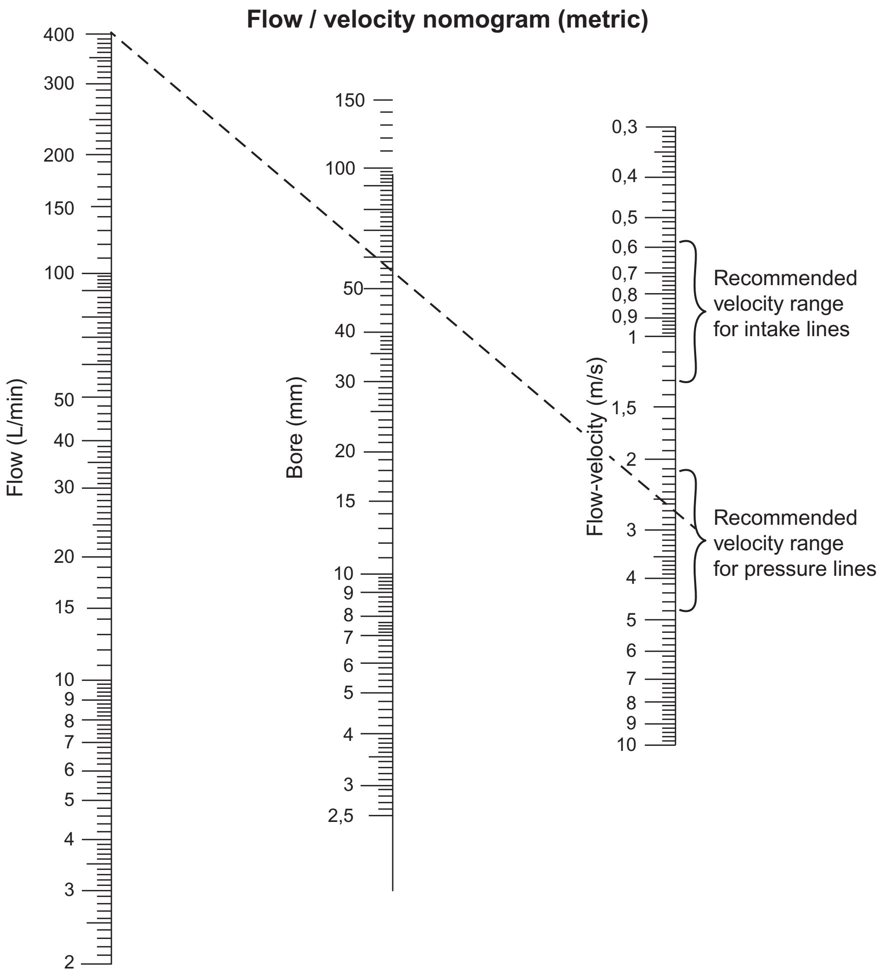




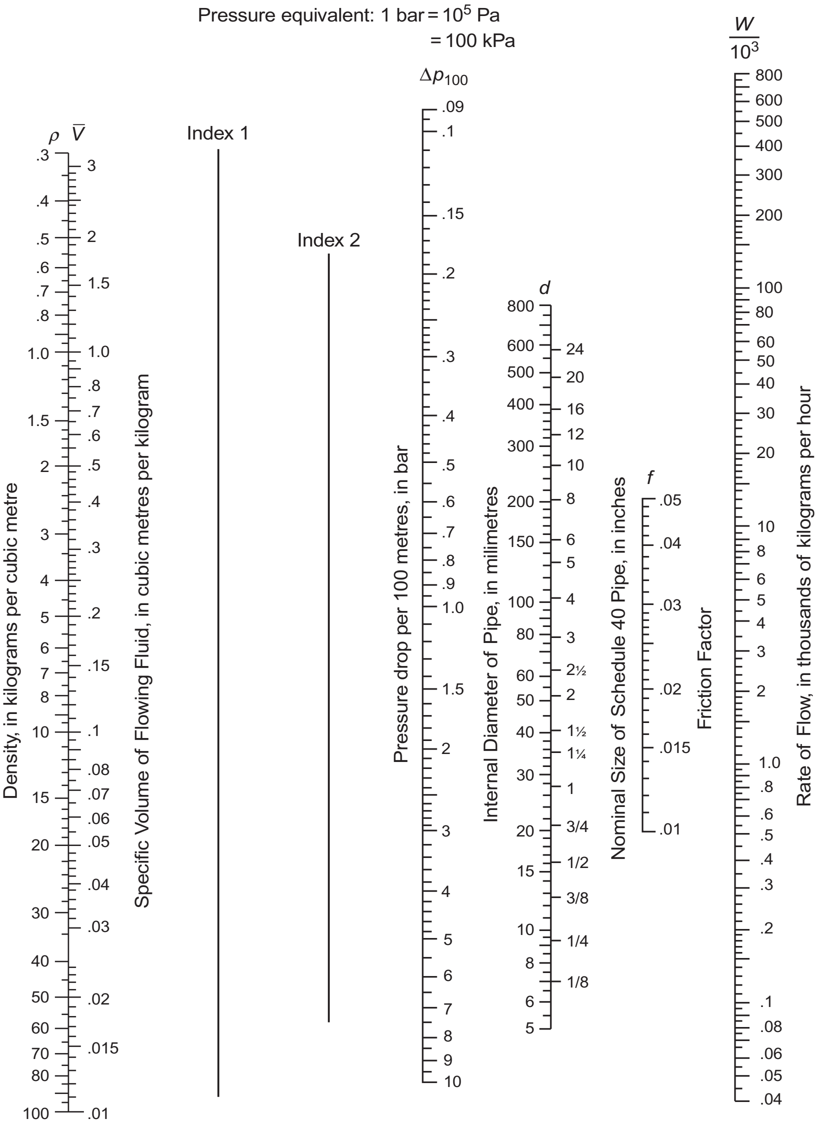
Friction Loss in Sch 40 Pipe



Nomograph for velocity of liquids in pipe

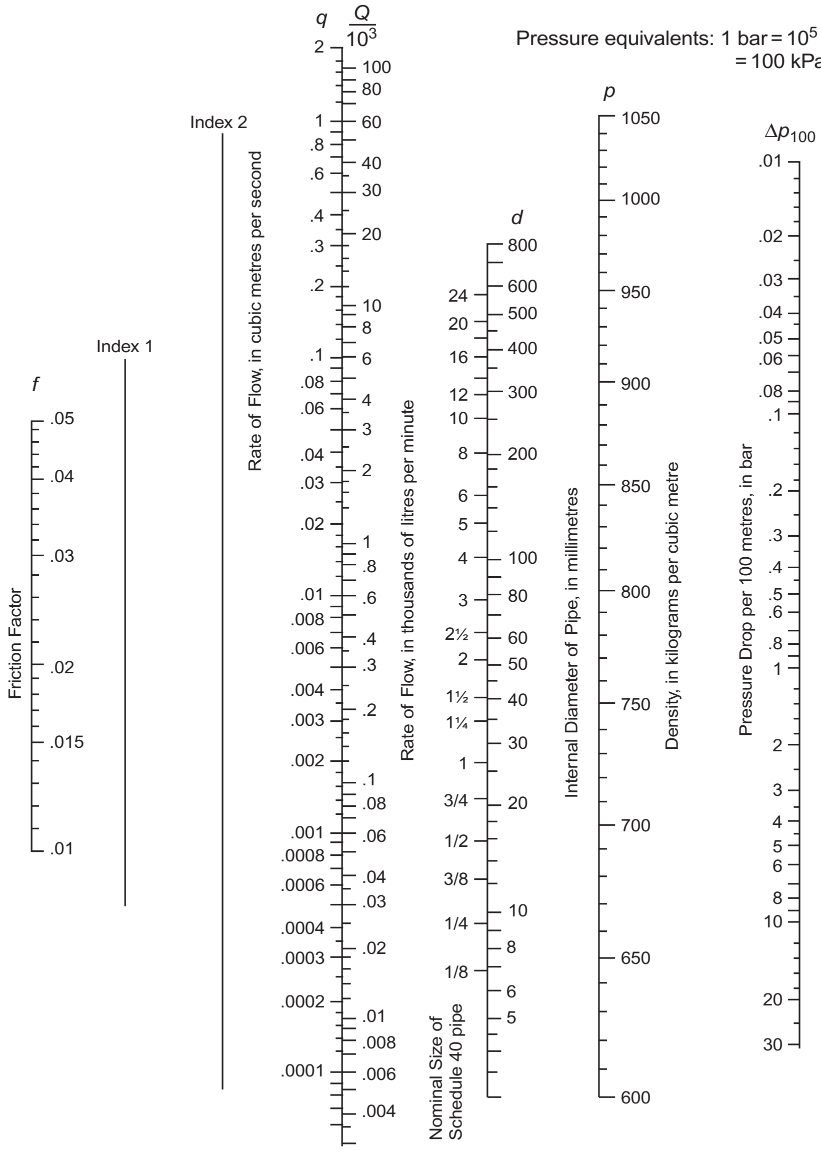

Flow / velocity nomogram (metric)
Flow (L/min)
400
300
200
150
100
50
40
30
20
15
10
9
8
7
6
5
4
3
2
Bore (mm)
150
100
50
40
30
20
15
10
9
8
7
6
5
4
3
2,5
Flow-velocity (m/s)
0,3
0,4
0,5
0,6
0,7
0,8
0,9
1
1,5
2
3
4
5
6
7
8
9
10
Recommended velocity range for intake lines
Recommended velocity range for pressure lines

Pressure drop in compressible flow lines (continued)



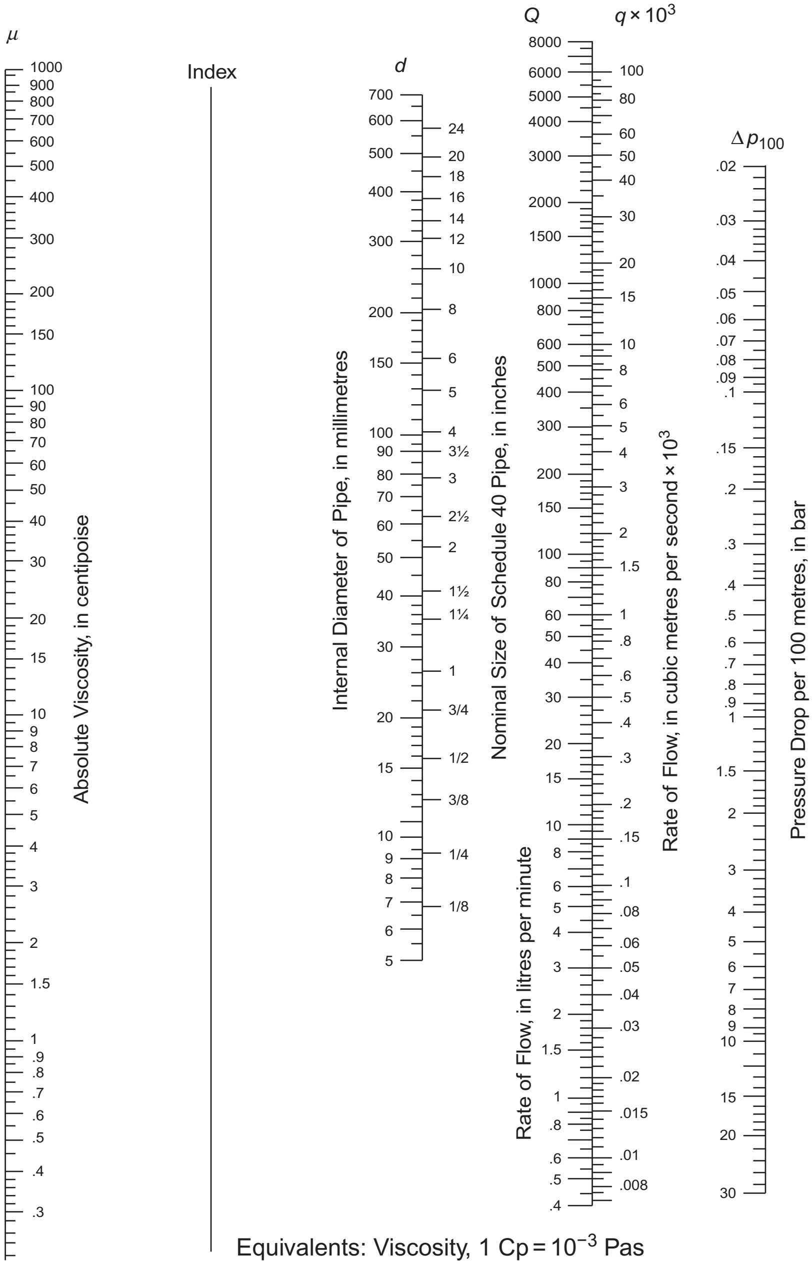
Nomograph for pressure drop in compressible flow lines

Pressure drop in liquid lines for turbulent flow (continued)

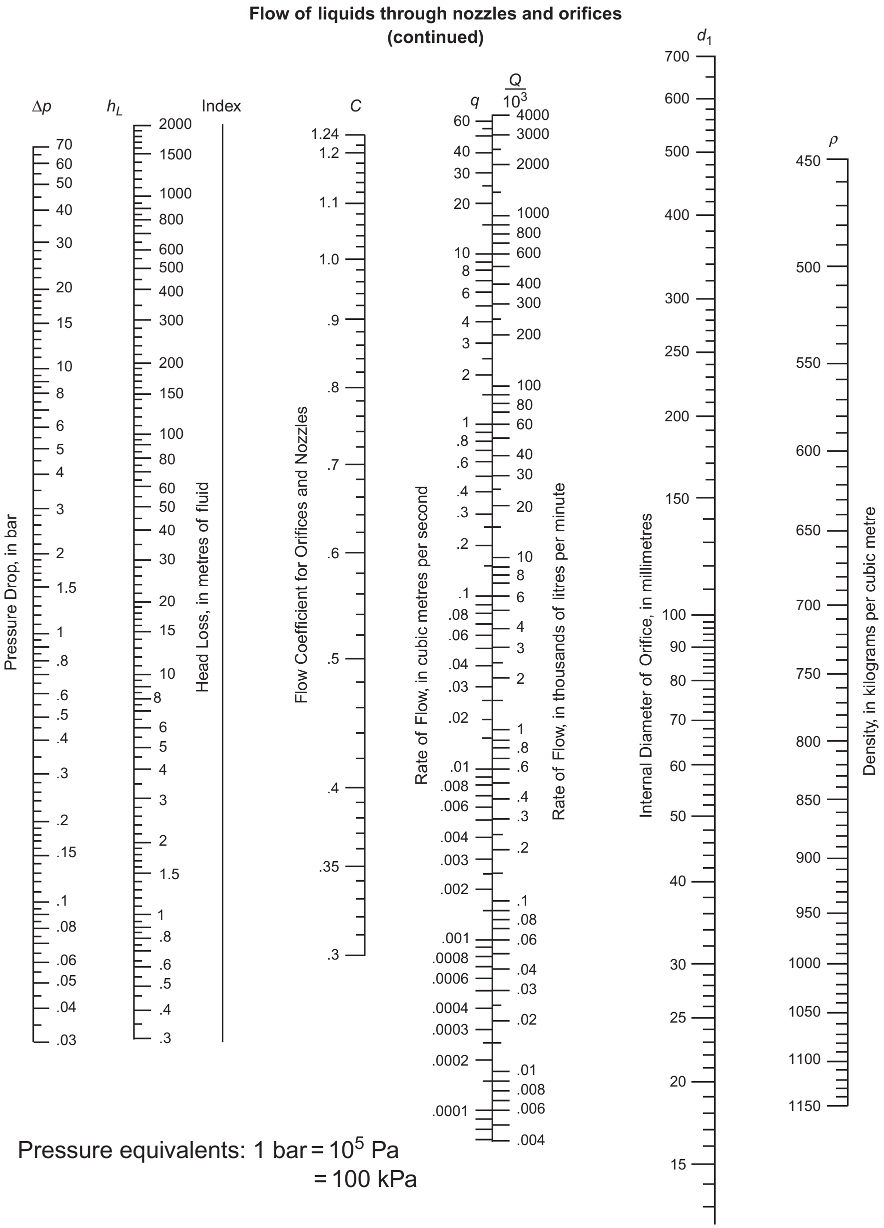


Nomograph for pressure drop in liquid lines for turbulent flow

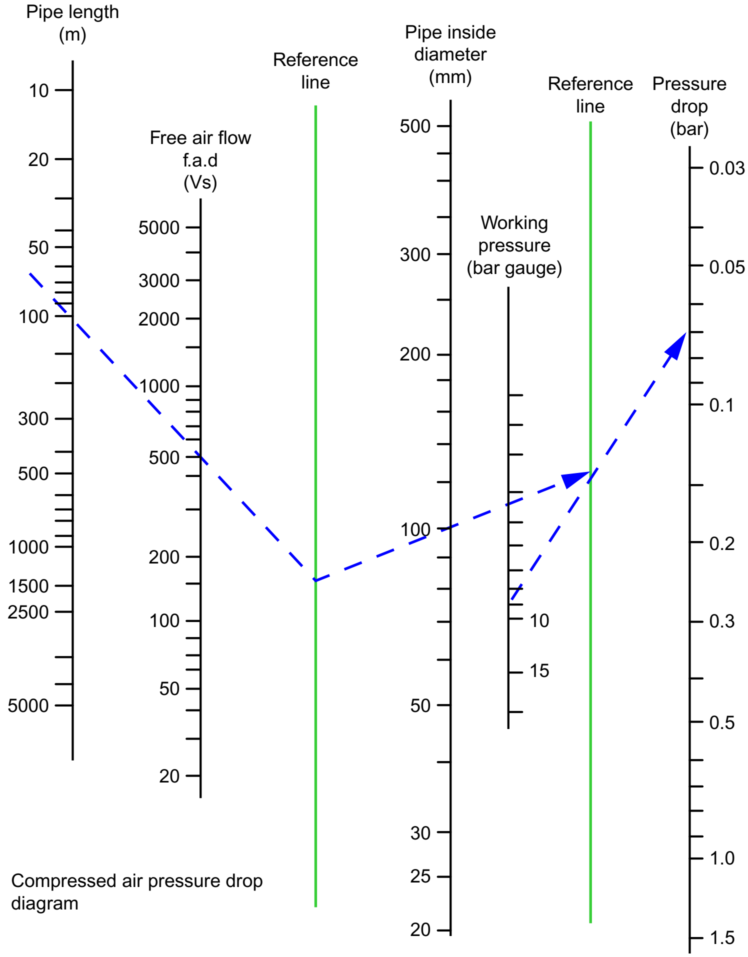
Pressure drop in liquid lines for laminar flow (continued)



Nomograph for pressure drop in lines for laminar flow

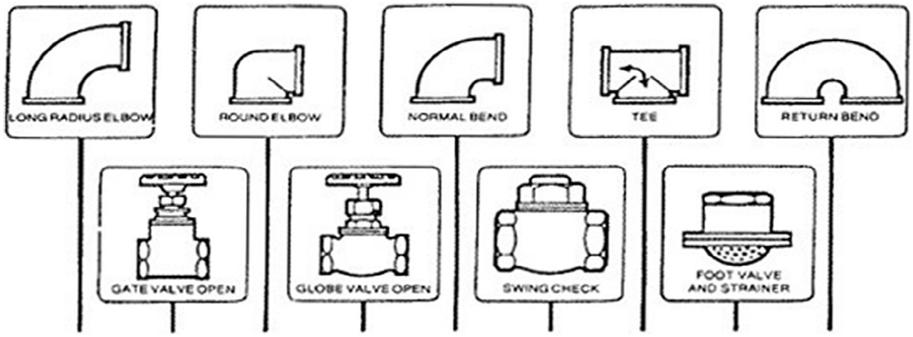


Nomograph for flow of liquids through nozzles and orifices



Compressed air pressure drop diagram

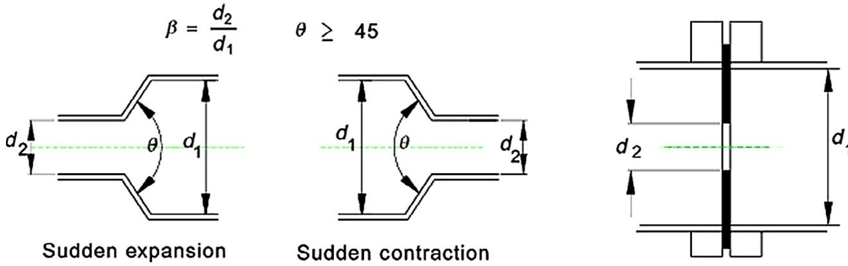
18.4 FLOW OF FLUIDS THROUGH VALVES AND FITTINGS



Pipe Size (mm)		Equivalent Length of Straight Pipe in Meters, for Calculating Friction Loss							
20	0.3	0.3	0.6	6.7	0.5	1.5	1.5	1.5	1.5
25	0.3	0.3	0.8	8.2	0.5	2.0	1.8	2.3	2.0
32	0.3	0.6	0.9	11.3	0.8	2.6	2.4	2.7	2.6
40	0.4	0.6	1.1	13.4	0.9	3.1	2.7	3.4	3.1
50	0.5	0.8	1.4	17.4	1.1	4.0	3.4	4.6	4.0
65	0.6	0.9	1.7	20.1	1.4	5.2	4.3	5.5	4.6
80	0.8	1.1	2.1	26.0	1.5	6.1	5.2	6.7	5.5
100	1.1	1.5	2.7	34.0	2.1	8.2	6.7	8.8	7.3
125	1.2	1.8	3.7	43.0	2.7	10.0	8.2	11.0	9.5
150	1.5	2.1	4.3	49.0	3.4	12.2	10.0	14.0	11.0
200	2.1	3.1	5.5	67.0	4.3	16.5	13.4	18.0	15.0
250	2.4	3.7	7.3	85.4	5.5	20.0	16.5	22.0	19.0
300	3.1	4.3	8.5	98.0	6.7	24.4	20.0	27.4	23.0

EQUIVALENT LENGTHS FOR VALVES AND FITTINGS

$\beta = \frac{d_2}{d_1}$ $\quad \theta \geq 45$



Sudden expansion

Sudden contraction

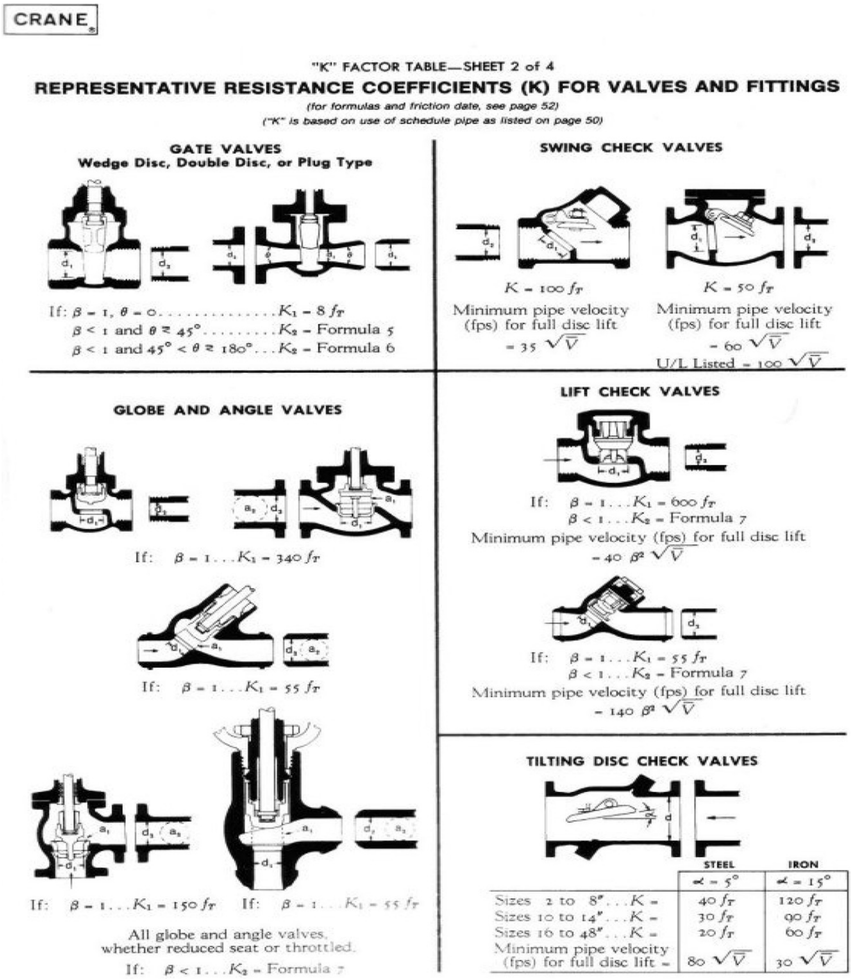
Orifice

$$K_e = \frac{(1-\beta^2)^2}{\beta^4}$$

$$K_c = \frac{0.5\,(1-\beta^2)\sqrt{\sin\frac{\theta}{2}}}{\beta^4}$$

$$K_o = K_c + K_e = \frac{0.5\,(1-\beta^2) + (1-\beta^2)^2}{\beta^4}$$

Diagram showing expansion and contraction and formulas



CRANE

"K" FACTOR TABLE—SHEET 2 of 4

REPRESENTATIVE RESISTANCE COEFFICIENTS (K) FOR VALVES AND FITTINGS

(for formulas and friction date, see page 52)

("K" is based on use of schedule pipe as listed on page 50)

GATE VALVES
Wedge Disc, Double Disc, or Plug Type

If: $\beta = 1, \theta = 0 \ldots\ldots K_1 = 8 f_T$
$\beta < 1$ and $\theta \leq 45° \ldots\ldots K_2 =$ Formula 5
$\beta < 1$ and $45° < \theta \leq 180° \ldots K_2 =$ Formula 6

SWING CHECK VALVES

$K = 100 f_T$
Minimum pipe velocity (fps) for full disc lift $= 35 \sqrt{\bar{V}}$

$K = 50 f_T$
Minimum pipe velocity (fps) for full disc lift $= 60 \sqrt{\bar{V}}$
U/L Listed $= 100 \sqrt{\bar{V}}$

GLOBE AND ANGLE VALVES

If: $\beta = 1 \ldots K_1 = 340 f_T$

If: $\beta = 1 \ldots K_1 = 55 f_T$

If: $\beta = 1 \ldots K_1 = 150 f_T$ If: $\beta = 1 \ldots K_1 = 55 f_T$

All globe and angle valves, whether reduced seat or throttled.
If: $\beta < 1 \ldots K_2 =$ Formula 7

LIFT CHECK VALVES

If: $\beta = 1 \ldots K_1 = 600 f_T$
$\beta < 1 \ldots K_2 =$ Formula 7
Minimum pipe velocity (fps) for full disc lift $= 40\ \beta^2 \sqrt{\bar{V}}$

If: $\beta = 1 \ldots K_1 = 55 f_T$
$\beta < 1 \ldots K_2 =$ Formula 7
Minimum pipe velocity (fps) for full disc lift $= 140\ \beta^2 \sqrt{\bar{V}}$

TILTING DISC CHECK VALVES

	STEEL $\alpha = 5°$	IRON $\alpha = 15°$
Sizes 2 to 8" ... K =	$40 f_T$	$120 f_T$
Sizes 10 to 14" ... K =	$30 f_T$	$90 f_T$
Sizes 16 to 48" ... K =	$20 f_T$	$60 f_T$
Minimum pipe velocity (fps) for full disc lift =	$80 \sqrt{\bar{V}}$	$30 \sqrt{\bar{V}}$

Representative Resistance Coefficients (K) for Vlaves & Fittings
(courtesy of the Crane Company)

"K" FACTOR TABLE

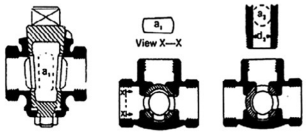
Representative Resistance Coefficients (K) for Valves and Fittings

(for formulas and friction data, see page A-26)

"K" is based on use of schedule pipe

PLUG VALVES AND COCKS

Straight-Way | 3-Way



If: $\beta = 1$, $K_1 = 18 f_T$ | If: $\beta = 1$, $K_1 = 30 f_T$ | If: $\beta = 1$, $K_1 = 90 f_T$

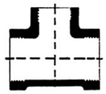
If: $\beta < 1$ K_2 = Formula 6

STANDARD ELBOWS

90° | 45°

$K = 30 f_T$ | $K = 16 f_T$

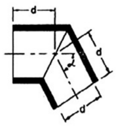
STANDARD TEES



Flow thru run......... $K = 20 f_T$

Flow thru branch...... $K = 60 f_T$

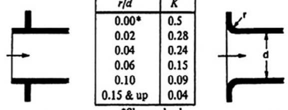
MITRE BENDS



α	K
0°	$2 f_T$
15°	$4 f_T$
30°	$8 f_T$
45°	$15 f_T$
60°	$25 f_T$
75°	$40 f_T$
90°	$60 f_T$

PIPE ENTRANCE

Inward Projecting | Flush



r/d	K
0.00*	0.5
0.02	0.28
0.04	0.24
0.06	0.15
0.10	0.09
0.15 & up	0.04

*Sharp-edged

$K = 0.78$ | For K, see table

90° PIPE BENDS AND FLANGED OR BUTT-WELDING 90° ELBOWS

r/d	K	r/d	K
1	$20 f_T$	8	$24 f_T$
1.5	$14 f_T$	10	$30 f_T$
2	$12 f_T$	12	$34 f_T$
3	$12 f_T$	14	$38 f_T$
4	$14 f_T$	16	$42 f_T$
6	$17 f_T$	20	$50 f_T$

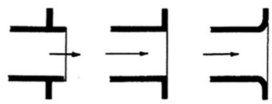
The resistance coefficient, K_B, for pipe bends other than 90° may be determined as follows:

$$K_B = (n-1)\left(0.25\,\pi f_T \frac{r}{d} + 0.5\,K\right) + K$$

n = number of 90° bends
K = resistance coefficient for one 90° bend (per table)

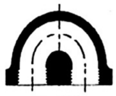
PIPE EXIT

Projecting | Sharp-Edged | Rounded



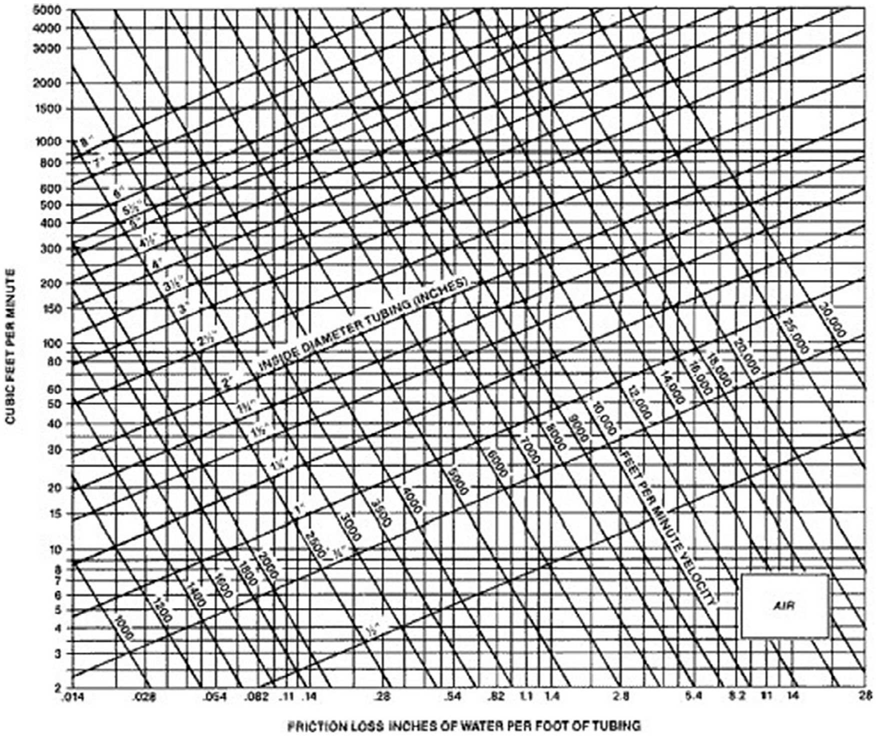
$K = 1.0$ | $K = 1.0$ | $K = 1.0$

CLOSE PATTERN RETURN BENDS

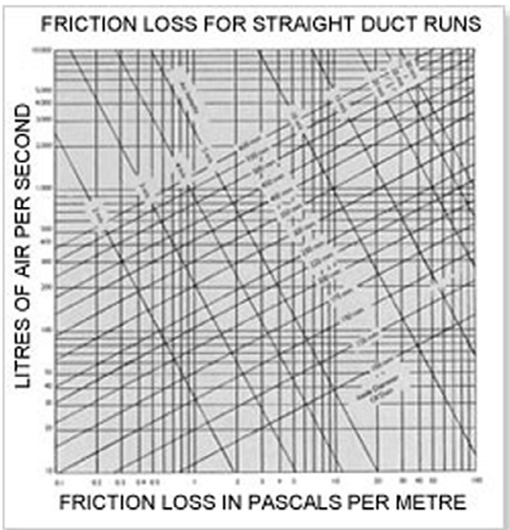


$K = 50 f_T$

Permission from the Crane Manufacturing Company, USA



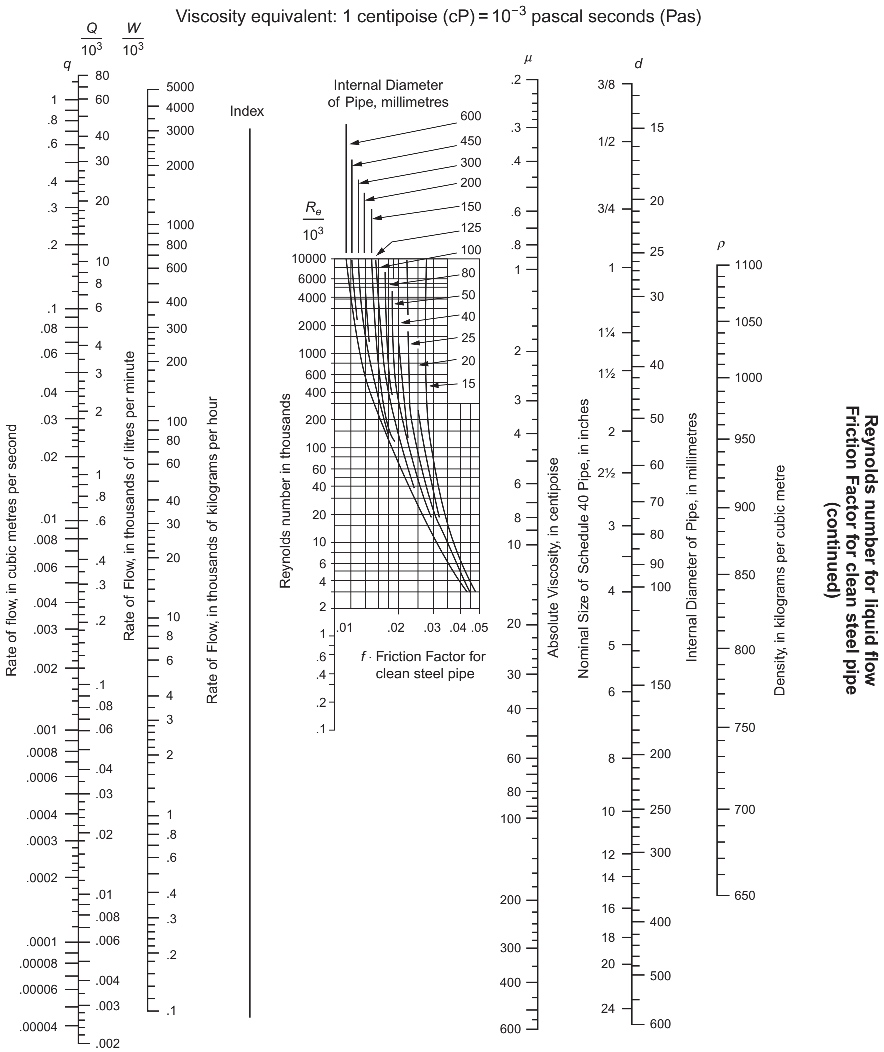
Nomograph for Friction Loss through Pipe



Friction Loss for Straight Duct Runs

Pressure drop through small diameter hose

Water* Flow Gal/min	Pressure Drop in PSI per 100 ft of Hose With Typical Water Flowrates Hose Inside Diameters, Inches					
	1/4	5/16	3/8	1/2	5/8	3/4	1
0.5	16	5	2				
1	54	20	7	2			
2	180	60	25	6	2		
3	380	120	50	13	4	2	
4		220	90	24	7	3	
5		320	130	34	10	4	
6			220	52	16	7	1
8			300	80	25	10	2
10				120	38	14	3
15				250	80	30	7
20					121	50	12
25					200	76	19
40					410	162	42
60						370	93



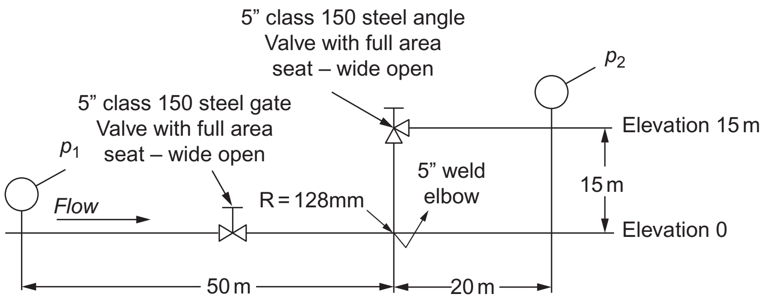
Nomograph for viscosity equivalents

LAMINAR FLOW IN VALVES, FITTINGS, AND PIPE

In flow problems where viscosity is high, calculate the Reynolds number to determine whether the flow is laminar or turbulent.

Example 18.1

Given: S.A.E. 70 Lube Oil at 40°C is flowing through 5-in. schedule 40 pipe at a rate of 2300 L/min, as shown in the following sketch.



Find: The velocity in metres per second and pressure difference between gauges p_1 and p_2.

*Shown in summary of formulas.

Solution

1. $v = \dfrac{21.22Q}{d^2}$ ....*

$Re = \dfrac{21.22Q_\rho}{d\mu}$ ....*

$\Delta p = \dfrac{0.00225K\rho Q^2}{d^4}$ loss due to flow;*

loss

$\Delta p = \dfrac{h_l\rho}{10{,}200}$ due to elevation change;*

2. $K_1 = 8\,f_T$ ...... gate valve; page A-27
$K_1 = 150\,f_T$ .... angle valve; page A-27
$K = 20\,f_T$ .... elbow; page A-29

$K = f\dfrac{L}{D}$ ....*

$f = \dfrac{64}{R_e}$ ....*

3. $d = 128.2$ .... 5″ Sched. 40 pipe; page B-16
$S = 0.916$ at 60°F (15.6°C) .... page A-7
$S = 0.90$ at 40°C .... page A-7
$\mu = 450$ .... page A-3
$\rho = 999 \times 0.9 = 899$ .... page A-6, A-7
$f_T = 0.016$ .... page A-26

4. $R_e = \dfrac{21.22 \times 2300 \times 899}{128.2 \times 450} = 760$

$R_e < 2000$; therefore flow is laminar.

5. $f = \frac{64}{760} = 0.084$

6. Summarizing K for the entire system (gate valve, angle valve, elbow, and pipe),

$$K = (8 \times 0.016) + (150 \times 0.016) + (20 \times 0.016) + \frac{(0.084 \times 85 \times 1000)}{128.2} = 58.54$$

7. $v = \frac{21.22 \times 2300}{128.2^2} = 2.97\,\text{m/s}$

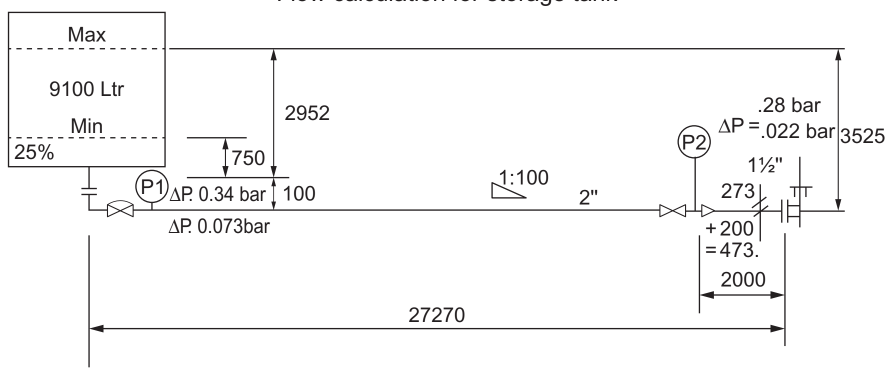
8. $$\Delta p = \frac{0.00225 \times 58.54 \times 899 \times 2300^2}{128.2^4} + \frac{15 \times 899}{10,200}$$

$\Delta p = 3.64\,\text{bar}$...........total

Laminar flow in valves, fittings and pipe (courtesy of the Crane Co.)

18.5 EXAMPLES OF FLOW PROBLEMS

Flow calculation for storage tank



$$\text{Average SG} = 0.8, \text{Do} = \text{SG } 0.796$$

$$\text{Temp} = \text{AMB } 20^{\circ}\text{C}, \text{Hs} = \text{SG } 0.808$$

To find the flow rate at the pump suction nozzle:

$$Q = 0.2087 d^2 \sqrt{\frac{h_l}{K}}$$

$$\mathrm{Re} = \frac{21.22Qp}{d\mu} \quad \begin{array}{l} \beta = d_1/d_2 \;\; K = 0.5\,(\text{entrance}) \;\; K = 14\,\text{ft}\left(90^{\circ}\ \text{elbow}\right) \\ K1 = 45\,\text{ft}\,(\text{diaphragm valve}) \;\; K = f\,l/d\,(\text{straight pipe}) \end{array}$$

$$K_2 = \frac{0.51\left(1-\beta^2\right)\sqrt{\sin v/2}}{B^4}\ \text{sudden contraction}$$

$$K = \frac{fI}{D\beta^4}\ \text{small pipe in terms of large pipe}$$

$$d = 48.36\,(2''\ \text{OD} \times 18\,\text{swg}\ 316\,\text{pipe})$$

$$d = 36.00\,(1½''\ \text{OD x}\ 18\,\text{swg}\ 316\,\text{pipe})$$

$$\mu = 1.1\,(\text{use water cP})\ \text{viscosity}$$

$$P = 998.2\,(\text{density})$$

$$\text{ft.} = 0.01\,(2''\ \text{pipe})$$

$$\text{ft.} = 0.021\,(1½''\ \text{pipe})$$

$$\beta = 36/48.36 = 0.74$$

$$K = 0.5\,(2''\ \text{entrance})$$

$$K = 14\,\text{x}\,0.019 = 0.266\left(2'' - 90^{\circ}\ \text{elbow}\right)$$

$$K_1 = \frac{0.019 \times 25 \times 1000}{48.36} = 9.822\ (\text{for}25\,\text{m}\ 2''\ \text{pipe})$$

$$K = \frac{0.021 \times 2 \times 1000}{36 \times 0.74} = 3.89$$

For 1½″ exit in terms of 3″ pipe

$$K = 1/0.74^4 = 3.34$$

$$\text{For sudden contraction}\ K_2 = \frac{0.5\left(1-0.74^2\right)(1)}{0.74} = 0.7543$$

$$K\ \text{total} = 0.5 + 0.266 + 1.71 + 9.822 + 3.89 + 3.34 + 0.7543 = 20.28$$

$$
\begin{aligned}
Q &= 0.2087 d^2 \sqrt{HI/K} \\
&= 0.2807 \times 48.36^2 \sqrt{3.525/20.28} \\
&= 203.4889\,\mathrm{L/min}
\end{aligned}
$$

$$Re = \frac{21.22 Qp}{d\mu}$$

$$2''\,pipe = \frac{21.22 \times 203.4889 \times 998.2}{48.36 \times 1.1}$$

$$(Re\text{ for } 2''\text{ pipe}) = 81{,}026.0545 = 8.1 \times 10^4$$

$$f = 0.034\ (\text{for } 2''\text{ pipe})$$

$$
\begin{aligned}
(\text{for } 11/2''\text{ pipe}) &= \frac{21.22 \times 203.4889 \times 998.2}{36 \times 1.1} \\
&= 1.08 \times 10^5
\end{aligned}
$$

$$f = 0.22\ (\text{for } 1½''\text{ pipe})$$

Since assumed friction factors used for straight pipe do not agree with f factors based on approx. flow rate. The K factors have to be adjusted.

$$\frac{0.034 \times 25 \times 1000}{48.36} \quad (2''\text{ pipe}, 25\,\mathrm{m})$$

For 2 m of 1½″ pipe in terms of 2″ pipe

$$\frac{0.022 \times 2 \times 1000}{36 \times 0.74} = 4.075$$

$$K\text{ total} = 0.5 + 0.266 + 1.71 + 17.57 + 4.075 + 3.34 + 0.7543$$

$$K = 28.21$$

$$
\begin{aligned}
Q &= 0.2087 \times 48.36^2 \sqrt{3.525/28.21} \\
&= 172.533\,\mathrm{L/min}\ (\text{full})\ \mathrm{MAX}
\end{aligned}
$$

Minimum based on 25% volume:

$$
\begin{aligned}
Q\text{ for } 25\% &= 0.2087 \times 48.36^2 \sqrt{0.750/28.21} \\
&= 79.58 L/\mathrm{min}\ (\mathrm{Min})
\end{aligned}
$$

2½″ pipe would give 139 L/min, 3″ pipe would give 219 L/min

Pressure Drop
Delta P

$$Q = W/0.06$$

$$\text{Therefore } 79 = W/0.06$$

$$W = 79 \times 0.06 \times 998.2 = 4731.46\,\text{kg/h}$$

$$F = 0.019 \text{ but use } 0.034 \text{ for } 2'' \text{ pipe}$$

$$F = 0.034, p = 998.22$$

$$Q = 79$$

$$2'' \text{ pipe delta } P = 0.19 \text{ bar}$$

$$\text{Check}: 62,530 fw^2/d^5 P = 62,530 \times 0.034 \times 4732^2/48.36^5 \times 998.2$$

$$\text{Delta } P = 0.1803 \text{ bar}$$

18.6 APPENDIX

To eliminate needless duplication, formulas have been written in terms of either specific volume $\overline{V}$ or density ρ, but not in terms of both, since one is the reciprocal of the other.

$$\overline{V} = \frac{1}{\rho}, \quad \rho = \frac{1}{\overline{V}}$$

These equations may be substituted in any of the formulas shown in this paper whenever necessary.

- Bernoulli's theorem:

$$Z + \frac{P}{\rho g_n} + \frac{v^2}{2g_n} = H$$
$$Z_1 + \frac{P_1}{\rho_1 g_n} + \frac{v_1^2}{2g_n} = Z_2 + \frac{P_2}{\rho_2 g_n} + \frac{v_2^2}{2g_n} + h_L \tag{18.1}$$

- **Mean velocity of flow in pipe** (Continuity equation):

$$v = \frac{q}{A} = 1,273,000\frac{q}{d^2} = 21.22\frac{Q}{d^2}$$

$$v = 56.23\,\frac{B}{d^2} = 1{,}273{,}000\,\frac{w\overline{V}}{d^2} = 354\,\frac{W\overline{V}}{d^2}$$

$$v = 1.243\,\frac{q'_h T}{p' d^2} = 433\,\frac{q'_h S_g}{\rho d^2}$$

$$V = \frac{q_m}{A} = 16{,}670\,\frac{W\overline{V}}{a} = 21{,}220\,\frac{W\overline{V}}{d^2}$$

$$V = 74.55\,\frac{q'_h T}{p' d^2} = 25{,}970\,\frac{q'_h S_g}{\rho d^2} \tag{18.2}$$

- **Reynolds number of flow in pipe:**

$$R_e = \frac{Dv\rho}{\mu'} = \frac{dv\rho}{1000\mu'} = \frac{dv\rho}{\mu}$$

$$R_e = 1{,}273{,}000\frac{q\rho}{d\mu} = 318.3\,\frac{q\rho}{R_H\mu} = 21.22\frac{Q\rho}{d\mu}$$

$$R_e = 354\frac{W}{d\mu} = 432\frac{q'_h S_g}{d\mu} = 56.23\frac{B\rho}{d\mu}$$

$$R_e = \frac{Dv}{v'} = \frac{dv}{1000v'} = 1000\frac{dv}{v}$$

$$R_e = 1273 \times 10^6\,\frac{q}{dv} = 21{,}220\frac{Q}{dv} = 354{,}000\frac{W\overline{V}}{dv} \tag{18.3}$$

- **Viscosity equivalents:**

$$v = \frac{\mu}{\rho'} = \frac{\mu}{S} \tag{18.4}$$

- **Head loss and pressure drop in straight pipe:**

Pressure loss due to flow is the same as in a sloping, vertical, or horizontal pipe. However, the difference in pressure due to the difference in head must be considered in pressure drop calculations:

Darcy's formula:

$$h_L = f\frac{L\,v^2}{D\,2g_n} = 51\frac{fLv^2}{d}$$

$$h_L = 8265\times 10^{10}\frac{fLq^2}{d^5} = 22{,}950\frac{fLQ^2}{d^5}$$

$$h_L = 161{,}200\frac{fLB^2}{d^5} = 6{,}376{,}000\frac{fLW^2\overline{V}^2}{d^5}$$

$$\Delta p = 0.005\frac{fL\rho v^2}{d} = 0.00000139\frac{fL\rho V^2}{d}$$

$$\Delta p = 81{,}055\times 10^5\frac{fL\rho q^2}{d^5} = 2.252\frac{fL\rho Q^2}{d^5}$$

$$\Delta p = 15.81\frac{fL\rho B^2}{d^5} = 625.3\frac{fLW^2\overline{V}}{d^5}$$

$$\Delta p = 2.69\frac{fLT\left(q_h'\right)^2 S_g}{d^5 p'}$$

$$\Delta p = 936.5\frac{fL\left(q_h'\right)^2 {S_g}^2}{d^5\rho} \tag{18.5}$$

- **Head loss and pressure drop with laminar flow in straight pipe:**

For laminar flow conditions ($R_e < 2000$), the friction factor is a direct mathematical function of the Reynolds number only, and can be expressed by the formula: $f = 64/R_e$. Substituting this value of f in the Darcy formula, it can be rewritten as

$$h_L = 3263\,\frac{\mu Lv}{d^2\rho}$$

$$h_L = 41{,}550\times 10^5\,\frac{\mu Lq}{d^4\rho} = 69{,}220\,\frac{\mu LQ}{d^4\rho}$$

$$h_L = 183{,}500\,\frac{\mu LB}{d^4\rho} = 1{,}154{,}000\,\frac{\mu LW}{d^4\rho^2}$$

$$\Delta p = 0.32\frac{\mu L v}{d^2} = 407{,}400\frac{\mu L q}{d^4}$$

$$\Delta p = 6.79\frac{\mu L Q}{d^4} = 18\frac{\mu L B}{d^4}$$

$$\Delta p = 113.2\frac{\mu L W}{d^4 \rho} \tag{18.6}$$

- **Limitations of Darcy formula**

Noncompressible flow; liquids:

The Darcy formula may be used without restriction for the flow of water, oil, and other liquids in pipe. However, when extreme velocities occurring in pipe cause the downstream pressure to fall to the vapor pressure of the liquid, cavitation occurs and calculated flow rates are inaccurate.

Compressible flow; gases and vapors:

When pressure drop is less than 10%, of p_1, use ρ or $\overline{V}$ based on either inlet or outlet conditions.

When pressure drop is greater than 10% of p_1 but less than 40% of p_1, use the average of ρ or V based on inlet and outlet conditions, or use Eq. (18.19).

When pressure drop is greater than 40% of p_1, use the rational or empirical formulas given on this page for compressible flow, or use Eq. (18.19).

- **Isothermal flow of gas in pipe lines**

$$w = 316.23\sqrt{\frac{A^2}{\overline{V}_1\left(f\frac{L}{D} + 2\log_e\frac{p_1'}{p_2'}\right)}\left(\frac{(p_1')^2 - (p_2')^2}{p_1'}\right)}$$

$$w = 0.0002484\sqrt{\frac{d^4}{\overline{V}_1\left(f\frac{L}{D} + 2\log_e\frac{p_1'}{p_2'}\right)}\left(\frac{(p_1')^2 - (p_2')^2}{p_1'}\right)} \tag{18.7}$$

- **Simplified compressible flow for long pipe lines**

$$w = 316.23\sqrt{\left(\frac{A^2}{\overline{V}_1 f\frac{L}{D}}\right)\left[\frac{(p_1')^2 - (p_2')^2}{p_1'}\right]}$$

$$w = 0.000007855\sqrt{\left(\frac{d^5}{\overline{V}_1 f L}\right)\left[\frac{(p'_1)^2-(p'_2)^2}{p'_1}\right]}$$

$$q'_h = 0.01361\sqrt{\left(\frac{(p'_1)^2-(p'_2)^2}{f L_m T S_g}\right)d^5} \tag{18.7a}$$

- **Maximum (sonic) velocity of compressible fluids in pipe**

The maximum possible velocity of a compressible fluid in a pipe is equivalent to the speed of sound in the fluid; this is expressed as

$$v_s = \sqrt{\gamma R T}$$

$$v_s = \sqrt{\gamma P' \overline{V}} = 316.2\sqrt{\gamma p' \overline{V}} \tag{18.8}$$

- **Empirical formulas for the flow of water, steam, and gas**

Although the rational method (using Darcy's formula) for solving flow problems has been recommended in this paper, some engineers prefer to use empirical formulas.

Hazen and Williams formula for flow of water:

$$Q = 0.000599 d^{2.63} c\left(\frac{p_1 - p_2}{L}\right)^{0.54} \tag{18.9}$$

where:

c = 140 for new steel pipe
c = 130 for new cast iron pipe
c = 110 for riveted pipe

Spitzglass formula for low pressure gas: [pressure less than 7000 N/m^2 (7 kPa)]

$$q'_h = 0.00338\sqrt{\frac{\Delta h_w d^5}{S_g L\left(1 + \frac{91.5}{d} + 0.00118 d\right)}} \tag{18.10}$$

Flowing temperature is 15°C

Weymouth formula for high pressure gas:

$$q'_h = 0.00261 d^{2.667}\sqrt{\left(\frac{(p'_1)^2-(p'_2)^2}{S_g L_m}\right)\left(\frac{288}{T}\right)} \tag{18.11}$$

Panhandle formula[3] for natural gas pipelines 150–600 mm diameter and $R_e = (5 \times 10^6)$ to (14×10^6):

$$q'_h = 0.00506 E d^{2.6182} \left(\frac{(p'_1)^2 - (p'_2)^2}{L_m} \right)^{0.5394} \tag{18.12}$$

where:

gas temperature = 15°C
$S_g = 0.6$
E = flow efficiency
E = 1.00 (100%) for brand new pipe without any bends, elbows, valves, and change of pipe diameter or elevation
E = 0.95 for very good operating conditions
E = 0.92 for average operating conditions
E = 0.85 for unusually unfavorable operating conditions

- **Head loss and pressure drop through valves and fittings**

Head loss through valves and fittings is generally given in terms of resistance coefficient K, which indicates static head loss through a valve in terms of "velocity head," or, equivalent length in pipe diameters L/D that will cause the same head loss as the valve.

From Darcy's formula, head loss through a pipe is

$$h_L = f \frac{L}{D} \frac{v^2}{2g_n} \tag{18.5}$$

and head loss through a valve is

$$h_L = K \frac{v^2}{2g_n} \tag{18.13}$$

therefore:

$$K = f \frac{L}{D} \tag{18.14}$$

To eliminate needless duplication of formulas, the following are all given in terms of K. Whenever necessary, substitute $(f\,L/D)$ for (K).

$$h_L = 8265 \times 10^7 \frac{Kq^2}{d^4} = 22.96 \frac{KQ^2}{d^4}$$

$$h_L = 161.2 \frac{KB^2}{d^4} = 6377 \frac{KW^2 \overline{V}^2}{d^4}$$

$$\Delta p = 0.000005 K\rho v^2 = 0.0001389 \times 10^{-5} K\rho V^2$$

$$\Delta p = 8,105,500 \frac{K\rho q^2}{d^4} = 0.00225 \frac{K\rho Q^2}{d^4}$$

$$\Delta p = 0.0158 \frac{K\rho B^2}{d^4}$$

$$\Delta p = 0.6253 \frac{KW^2 \overline{V}}{d^4}$$

$$\Delta p = 0.00269 \frac{K\left(q'_h\right)^2 T\,Sg}{d^4 p'}$$

$$\Delta p = 0.9365 \frac{K\left(q'_h\right)^2 Sg^2}{d^4 \rho} \tag{18.13}$$

For compressible flow with h_L or Δ_p greater than approximately 10% of inlet absolute pressure, the denominator should be multiplied by Y^2.

- **Flow coefficient**

As explained on page 2-10 there is not yet an agreed definition for a flow coefficient in terms of SI units. The equations given below relate to C_v as expressed in Imperial units with flow rate in UK or US gallons per minute.

Flow rate *Q* in UK gal/min:

$$C_v = Q\sqrt{\frac{\rho}{\Delta P(62.4)}} = \frac{24.9d^2}{\sqrt{fL/D}} = \frac{24.9d^2}{\sqrt{K}} \tag{18.15}$$

Flow rate *Q* in US gal/min:

$$C_v = Q\sqrt{\frac{\rho}{\Delta P(62.4)}} = \frac{29.9d^2}{\sqrt{fL/D}} = \frac{29.9d^2}{\sqrt{K}}$$

where:

ρ = density of liquid in lb/ft^3
ΔP = pressure drop, in lbf/in^2
d = internal diameter, in inches
L/D = equivalent length of valve in pipe diameters
f = friction factor
K = resistance coefficient

- **Resistance coefficient, *K*, for sudden and gradual enlargements in pipes**

For $\theta \overline{\overline{<}} 45°$,

$$K_1 = 2.6 \sin\frac{\theta}{2}\left(1-\beta^2\right)^2 \tag{18.16*}$$

For $45° < \theta \overline{\overline{<}} 180°$,

$$K_1 = \left(1-\beta^2\right)^2 \tag{18.16.1*}$$

- **Resistance coefficient, K, for sudden and gradual contractions in pipes**

For $\theta \leqq 45°$,

$$K_1 = 0.8 \sin\frac{\theta}{2}\left(1-\beta^2\right) \tag{18.17*}$$

For $45° < \theta \leqq 180°$,

$$K_1 = 0.5\sqrt{\sin\frac{\theta}{2}\left(1-\beta^2\right)} \tag{18.17.1*}$$

***Note**: The values of the resistance coefficients (K) in Eqs. (18.16), (18.16.1), (18.17), (18.17.1) are based on the velocity in the small pipe. To determine K values in terms of the greater diameter, divide the equations by β^4.

- **Discharge of fluid through valves, fittings, and pipe; Darcy's formula**

Liquid flow:

$$q = 0.000003478\, d^2\sqrt{\frac{h_L}{K}} = 0.0003512\, d^2\sqrt{\frac{\Delta p}{K\rho}}$$

$$Q = 0.2087\, d^2\sqrt{\frac{h_L}{K}} = 21.07\, d^2\sqrt{\frac{\Delta p}{K\rho}}$$

$$w = 0.000003478\,\rho d^2\sqrt{\frac{h_L}{K}} = 0.0003512\, d^2\sqrt{\frac{\Delta p\rho}{K}}$$

$$W = 0.01252\,\rho d^2\sqrt{\frac{h_L}{K}} = 1.265\, d^2\sqrt{\frac{\Delta p\rho}{K}} \tag{18.18}$$

Compressible flow:

$$q'_h = 19.31\, Yd^2\sqrt{\frac{\Delta p p'_1}{KT_1 Sg}}$$

$$q'_h = 1.0312\,\frac{Yd^2}{S_g}\sqrt{\frac{\Delta p\rho_1}{K}}$$

$$q'_m = 0.3217\, Yd^2\sqrt{\frac{\Delta p p'_1}{KT_1 S_g}} = 0.01719\,\frac{Yd^2}{S_g}\sqrt{\frac{\Delta p\rho_1}{K}}$$

$$q' = 0.005363\, Yd^2\sqrt{\frac{\Delta p p'_1}{KT_1 S_g}} = 0.0002864\,\frac{Yd^2}{S_g}\sqrt{\frac{\Delta p\rho_1}{K}}$$

$$w = 0.0003512Yd^2\sqrt{\frac{\Delta p}{K\bar{V}_1}} \quad w = 1.265\,Yd^2\sqrt{\frac{\Delta p}{K\bar{V}_1}} \tag{18.19}$$

- **Flow through nozzles and orifices** (h_L and Δp measured across taps at 1 diameter and 0.5 diameter)

Liquid:

$$q = Av = AC\sqrt{2g_n h_L} = AC\sqrt{\frac{2\Delta P}{\rho}}$$

$$q = 0.00000348d_1^2\sqrt[c]{h_L} = 0.0003512\mathrm{d}_1^2\sqrt[c]{\frac{\Delta \mathrm{p}}{\rho}}$$

$$Q = 0.2087d_1^2\sqrt[c]{h_L} = 21.07\mathrm{d}_1^2\sqrt[c]{\frac{\Delta \mathrm{p}}{\rho}}$$

$$w = 0.00000348d_1^2\sqrt[c]{h_L\rho^2} = 0.0003512d_1^2\sqrt[c]{\Delta p\rho}$$

$$w = 0.01252d_1^2\sqrt[c]{h_L\rho^2} = 1.265d_1^2\sqrt[c]{\Delta p\rho} \tag{18.20}$$

Compressible fluids:

$$q_h' = 19.31Yd_1^2\sqrt[c]{\frac{\Delta p p_1'}{T_1 S_g}}$$

$$q_n' = 1.0312\frac{Yd_1^2C}{S_g}\sqrt{\Delta p\rho_1}$$

$$q_m' = 0.3217Yd_1^2\sqrt[c]{\frac{\Delta p p_1'}{T_1 S_g}}$$

$$q_m' = 0.01719\frac{Yd_1^2}{S_g}\sqrt[c]{\Delta p\rho_1}$$

$$q = 0.005363Yd_1^2\sqrt[c]{\frac{\Delta pp_1'}{T_1 S_g}}$$

$$q' = 0.0002864 \frac{Y d_1^2 C}{S_g} \sqrt{\Delta p \rho},$$

$$w = 0.0003512 Y d_1^2 \sqrt[c]{\frac{\Delta p}{\overline{V}_1}}$$

$$W = 1.265 Y d_1^2 \sqrt[c]{\frac{\Delta p}{\overline{V}_1}} \tag{18.21}$$

d_1 = nozzle or orifice diameter

- **Equivalents of head loss and pressure drop**

$$h_L = \frac{10200 \Delta p}{\rho} \quad \Delta p = \frac{h_L \rho}{10200} \tag{18.22}$$

- **Changes in resistance coefficient *K* required to compensate for different pipe inside diameter:**

$$Ka = Kb \left(\frac{da}{db}\right)^4 \tag{18.23}$$

(see page 2-10)

Subscript *a* refers to pipe in which valve will be installed. Subscript *b* refers to pipe for which the resistance coefficient *K* was established.

- **Specific gravity of liquids**

Any liquid:

$$s = \frac{\rho\left(\text{any liquid at } 60^\circ\text{F } (15.6^\circ\text{C}) \text{ unless otherwise specified}\right)}{\rho\left(\text{water at } 60^\circ\text{F } (15.6^\circ\text{C})\right)} \tag{18.24}$$

Oils:

$$S\left(60^\circ\text{F}/60^\circ\text{F}\right) = \frac{141.5}{131.5 + \text{Deg API}} \tag{18.25}$$

Liquids lighter than water:

$$S\left(60^\circ\text{F}/60^\circ\text{F}\right) = \frac{140}{130 + \text{Deg Baumé}} \tag{18.26}$$

Liquids heavier than water:

$$S\left(60^\circ\text{F}/60^\circ\text{F}\right) = \frac{145}{145 - \text{Deg Baumé}} \tag{18.27}$$

- **Specific gravity of gases**

$$S_g = \frac{R\,(\text{air})}{R\,(\text{gas})} = \frac{287}{R\,(\text{gas})}$$

$$S_g = \frac{M\,(\text{gas})}{M\,(\text{air})} = \frac{M\,(\text{gas})}{29} \tag{18.28}$$

- **General gas laws for perfect gases**

$$P'V_a = w_a RT \tag{18.29}$$

$$\rho = \frac{w_a}{V_a} = \frac{P'}{RT} = \frac{10^5 p'}{RT} \tag{18.30}$$

$$R = \frac{8314}{M} = \frac{P'}{\rho T} \tag{18.31}$$

$$P'V_a = n_a MRT = n_a 8314T = \frac{w_a}{M} 8314T \tag{18.32}$$

$$\rho = \frac{w_a}{V_a} = \frac{P'M}{8314T} = \frac{P'S_g}{287T} = \frac{348.4p'S_g}{T} \tag{18.33}$$

where $n_a = w_a/M$ = number of moles of a gas

- **Hydraulic radius***

$$R_H = \frac{\text{cross sectional flow area (square metres)}}{\text{wetted perimeter (metres)}} \tag{18.34}$$

Equivalent diameter relationship:

$$D = 4R_H$$

$$d = 4000\,R_H$$

Commercial Steel Pipe				
Based on ANSI B36.10:1970 and BS 1600: Part 2: 1970				
Schedule Wall Thicknesses				
	Nominal Pipe Size	Outside Diameter	Thickness	Inside Diameter
	Inches	mm	mm	mm
Schedule 10	14	355.6	6.35	342.9
	16	406.4	6.35	393.7
	18	457.2	6.35	444.5
	20	508.0	6.35	495.3
	24	609.6	6.35	596.9
	30	762.0	7.92	746.2
Schedule 20	8	219.1	6.35	206.4
	10	273.0	6.35	260.3
	12	323.9	6.35	311.2
	14	355.6	7.92	339.8
	16	406.4	7.92	390.6
	18	457.2	7.92	441.4
	20	508.0	9.52	489.0
	24	609.6	9.52	590.6
	30	762.0	12.70	736.6
Schedule 30	8	219.1	7.04	205.0
	10	273.0	7.80	257.4
	12	323.9	8.38	307.1
	14	355.6	9.52	336.6
	16	406.4	9.52	387.4
	18	457.2	11.13	434.9
	20	508.0	12.70	482.6
	24	609.6	14.27	581.1
	30	762.0	15.88	730.2
Schedule 40	1/8	10.3	1.73	6.8
	¼	13.7	2.24	9.2
	3/8	17.1	2.31	12.5
	½	21.3	2.77	15.8
	¾	26.7	2.87	21.0
	1	33.4	3.38	26.6
	1¼	42.2	3.56	35.1
	1½	48.3	3.68	40.9
	2	60.3	3.91	52.5

Continued

Commercial Steel Pipe				
Based on ANSI B36.10:1970 and BS 1600: Part 2: 1970				
Schedule Wall Thicknesses				
	Nominal Pipe Size	Outside Diameter	Thickness	Inside Diameter
	Inches	mm	mm	mm
	2½	73.0	5.16	62.7
	3	88.9	5.49	77.9
	3½	101.6	5.74	90.1
	4	114.3	6.02	102.3
	5	141.3	6.55	128.2
	6	168.3	7.11	154.1
	8	219.1	8.18	202.7
	10	273.0	9.27	254.5
	12	323.9	10.31	303.3
	14	355.6	11.13	333.3
	16	406.4	12.70	381.0
	18	457.2	14.27	428.7
	20	508.0	15.09	477.8
	24	609.6	17.48	574.6
Schedule 60	8	219.1	10.31	198.5
	10	273.0	12.70	247.6
	12	323.9	14.27	295.4
	14	355.6	15.09	325.4
	16	406.4	16.64	373.1
	18	457.2	19.05	419.1
	20	508.0	20.62	466.8
	24	609.6	24.61	560.4
Schedule 80	1/8	10.3	2.41	5.5
	¼	13.7	3.02	7.7
	3/8	17.1	3.20	10.7
	½	21.3	3.73	13.8
	¾	26.7	3.91	18.9
	1	33.4	4.55	24.3
	1¼	42.2	4.85	32.5
	1½	48.3	5.08	38.1
	2	60.3	5.54	49.2
	2½	73.0	7.01	59.0
	3	88.9	7.62	73.7
	3½	101.6	8.08	85.4

Continued

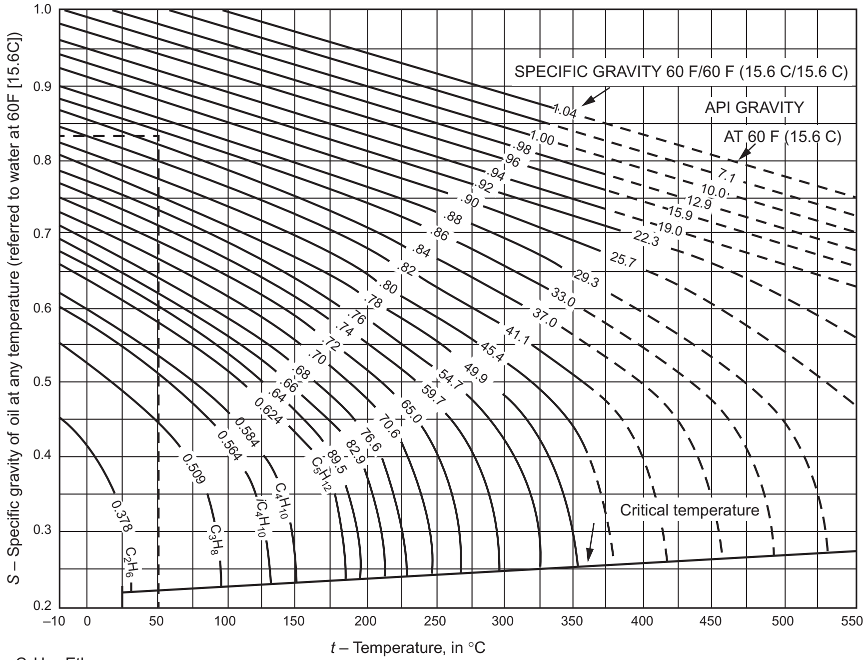
Commercial Steel Pipe				
Based on ANSI B36.10:1970 and BS 1600: Part 2: 1970				
Schedule Wall Thicknesses				
	Nominal Pipe Size	Outside Diameter	Thickness	Inside Diameter
	Inches	mm	mm	mm
	4	114.3	8.56	97.2
	5	141.3	9.52	122.3
	6	168.3	10.97	146.4
	8	219.1	12.70	193.7
	10	273.0	15.09	242.8
	12	323.9	17.47	289.0
	14	355.6	19.05	317.5
	16	406.4	21.44	363.5
	18	457.2	23.82	409.6
	20	508.0	26.19	455.6
	24	609.6	30.96	547.7
Schedule 100	8	219.1	15.09	188.9
	10	273.0	18.26	236.5
	12	323.9	21.44	281.0
	14	355.6	23.82	308.0
	16	406.4	26.19	354.0
	18	457.2	29.36	398.5
	20	508.0	32.54	442.9
	24	609.6	38.89	531.8
Schedule 120	4	114.3	11.13	92.0
	5	141.3	12.70	115.9
	6	168.3	14.27	139.8
	8	219.1	18.26	182.6
	10	273.0	21.44	230.1
	12	323.9	25.40	273.1
	14	355.6	27.79	300.0
	16	406.4	30.96	344.5
	18	457.2	34.92	387.4
	20	508.0	38.10	431.8
	24	609.6	46.02	517.6
Schedule 140	8	219.1	20.62	177.9
	10	273.0	25.40	222.2
	12	323.9	28.58	266.7
	14	355.6	31.75	292.1

Continued

Commercial Steel Pipe				
Based on ANSI B36.10:1970 and BS 1600: Part 2: 1970				
Schedule Wall Thicknesses				
	Nominal Pipe Size	Outside Diameter	Thickness	Inside Diameter
	Inches	mm	mm	mm
	16	406.4	36.52	333.4
	18	457.2	39.69	377.8
	20	508.0	44.45	419.1
	24	609.6	52.39	504.8
Schedule 160	½	21.3	4.78	11.7
	¾	26.7	5.56	15.6
	1	33.4	6.35	20.7
	1¼	42.2	6.35	29.5
	1½;	48.3	7.14	34.0
	2	60.3	8.74	42.8
	2½	73.0	9.52	54.0
	3	88.9	11.13	66.6
	4	114.3	13.49	87.3
	5	141.3	15.88	109.5
	6	168.3	18.26	131.8
	8	219.1	23.01	173.1
	10	273.0	28.58	215.8
	12	323.9	33.34	257.2
	14	355.6	35.71	284.2
	16	406.4	40.49	325.4
	18	457.2	45.24	366.7
	20	508.0	50.01	408.0
	24	609.6	59.54	490.5

Commercial Steel Pipe Data (courtesy of Crane Co.)

Specific gravity-temperature relationship for petroleum oils



C_2H_6 = Ethane
C_3H_8 = Propane iC_4H_{10} = Isobutane
C_4H_{10} = Butane iC_5H_{12} = Isopentane

Example: The specific gravity of an oil at 15.6 C is 0.85. The specific gravity at 50 C = 0.83.

To find the density in kilograms/cubic metre of a petroleum oil at its flowing temperature when the specific gravity at 60 F/60 F (15.6 C/15.6 C) is known, multiply the specific gravity of the oil at flowing temperature (see chart above) by 999, the density of water at 60 F (15.6 C).

Density and Specific Gravity[a] of Various Liquids

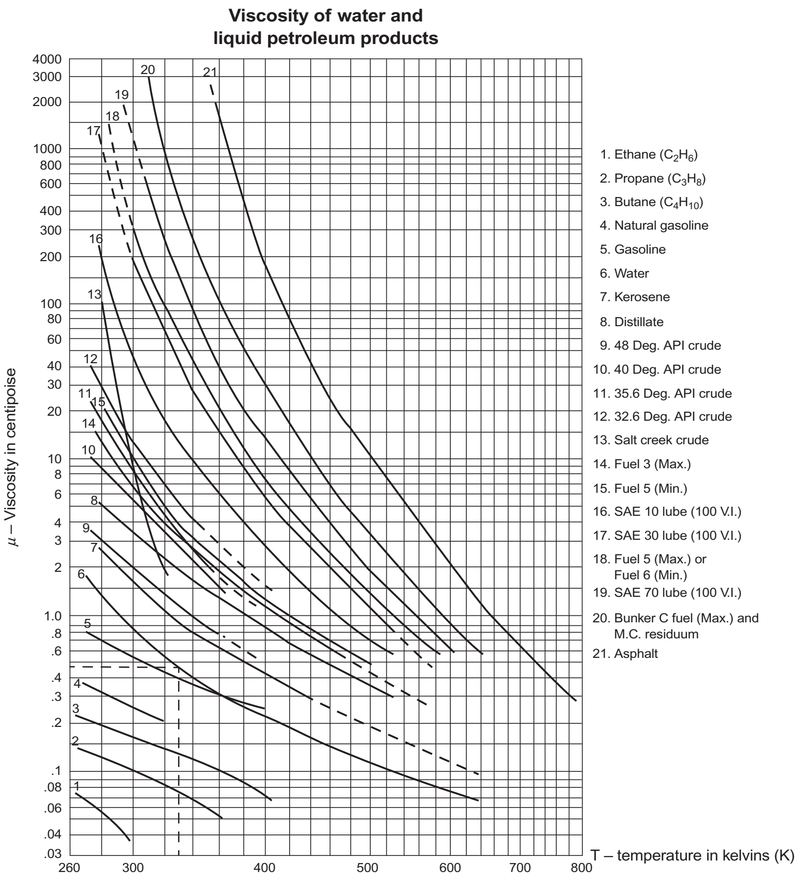
Liquid	**Temp.**		**Density**	**Specific Gravity**
	T		***ρ***	***S***
	°F	**°C**	**kg/m³**	
Acetone	60	15.6	791.3	0.792
Ammonia, Saturated	10	−12.2	655.2	0.656
Benzene	32	0	898.6	0.899
Brine, 10% Ca Cl	32	0	1090.1	1.091
Brine. 10% Na Cl	32	0	1077.1	1.078
Bunkers C Fuel Max.	60	15.6	1013.2	1.014
Carbon Disulfide	32	0	1291.1	1.292
Distillate	60	15.6	848.8	0.850
Fuel 3 Max.	60	15.6	897.4	0.898
Fuel 5 Min.	60	15.6	964.8	0.966

Continued

Density and Specific Gravity[a] of Various Liquids				
Liquid	Temp.		Density	Specific Gravity
	T		ρ	*S*
	°F	°C	kg/m^3	
Fuel 5 Max.	60	15.6	991.9	0.993
Fuel 6 Min.	60	15.6	991.9	0.993
Gasoline	60	15.6	749.8	0.751
Gasoline, Natural	60	15.6	679.5	0.680
Kerosene	60	15.6	814.5	0.815
M. C. Residuum	60	15.6	934.2	0.935
Mercury	20	−6.7	13 612	13.623
Mercury	40	4.4	13 584	13.596
Mercury	60	15.6	13 557	13.568
Mercury	80	26.7	13 530	13.541
Mercury	100	37.8	13 502	13.514
Milk	…	…	[b]	…
Olive Oil	59	15.0	917.9	0.919
Pentane	59	15.0	623.1	0.624
SAE 10 Lube[c]	60	15.6	875.3	0.876
SAE 30 Lube[c]	60	15.6	897.4	0.898
SAE 70 Lube[c]	60	15.6	915.0	0.916
Salt Creek Crude	60	15.6	841.9	0.843
32.6° API Crude	60	15.6	861.3	0.862
35.6° API Crude	60	15.6	845.9	0.847
40° API Crude	60	15.6	824.2	0.825
48° API Crude	60	15.6	787.5	0.788

[a] *Liquid at specified temperature relative to water at 15.6°C (60°F).*
[b] *Milk has a density of 1028–1035 kg/m^3.*
[c] *100 Viscosity Index.*

SPECIFIC GRAVITY–TEMPERATURE RELATIONSHIPS FOR PETROLEUM OILS (COURTESY OF CRANE CO.)



Example: Find the viscosity of water at 60°C

Solution: 60°C = 273 + 60 = 333 K
Viscosity of water at 333 K = 0.47 centipoise (curve 6)

Viscosity of Water & Liquid Petroleum products

PHYSICAL PROPERTIES OF WATER

Temperature of Water	Saturation Pressure	Specific Volume	Density
T	p'	$\overline{V} \times 10^3$	p
°C	Bar Absolute	dm^3/kg	kg/m^3
0.01	0.006112	1.0002	999.8
5	0.008719	1.0001	999.9
10	0.012271	1.0003	999.7
15	0.017041	1.0010	999.0
20	0.023368	1.0018	998.2
25	0.031663	1.0030	997.0
30	0.042418	1.0044	995.6
35	0.056217	1.0060	994.0
40	0.073750	1.0079	992.2
45	0.09582	1.0099	990.2
50	0.12335	1.0121	988.0
55	0.15740	1.0145	985.7
60	0.19919	1.0171	983.2
65	0.25008	1.0199	980.5
70	0.31160	1.0228	977.7
75	0.38547	1.0258	974.8
80	0.47359	1.0290	971.8
85	0.57803	1.0324	968.6
90	0.70109	1.0359	965.3
95	0.84526	1.0396	961.9
100	1.01325	1.0435	958.3
110	1.4326	1.0515	951.0
120	1.9853	1.0603	943.1
130	2.7012	1.0697	934.8
140	3.6136	1.0798	926.1
150	4.7597	1.0906	916.9
160	6.1805	1.1021	907.4
170	7.9203	1.1144	897.3
180	10.0271	1.1275	886.9
190	12.552	1.1415	876.0
200	15.551	1.1565	864.7
225	25.504	1.1992	833.9
250	39.776	1.2512	799.2
275	59.49	1.3168	759.4
300	85.92	1.4036	712.5
325	120.57	1.5289	654.1
350	165.37	1.741	574.4
374.15	221.20	3.170	315.5

To convert Specific Volume from cubic decimeters per kilogram (dm^3/kg) to cubic meters per kilogram (m^3/kg) divide values in table by 10^3.

To convert Density from kilograms per cubic meter (kg/m^3) to kilograms per liter (kg/L) divide values in table by 10^3.

Specific gravity of water at 15°C = 1.00.

Data on pressure and volume abstracted from the UK National Engineering Laboratory "Steam Tables 1964" with permission of HMSO.

PHYSICAL PROPERTIES OF WATER

"K" factor table

Representative Resistance Coefficients (*K*) for Valves and Fittings

"K" is based on use of schedule pipe

Pipe Friction Data For Clean Commercial Steel Pipe with Flow in Zone of Complete Turbulence

	mm	**15**	**20**	**25**	**32**	**40**	**50**	**65, 80**	**100**	**125**	**150**	**200, 250**	**300–400**	**450-600**
Nominal Size	**in.**	**½**	**¾**	**1**	**1¼**	**1½**	**2**	**2½, 3**	**4**	**5**	**6**	**8, 10**	**12–16**	**18–24**
Friction Factor (f_T)		0.027	0.025	0.023	0.022	0.021	0.019	0.018	0.017	0.016	0.015	0.014	0.013	0.012

Formulas for calculating “K” factors* for valves and fittings with reduced port

Formula 1

$$K_2 = \frac{0.8 \sin\frac{\theta}{2}\left(1-\beta^2\right)}{\beta^4} = \frac{K_1}{\beta^4}$$

Formula 2

$$K_2 = \frac{0.5\left(1-\beta^2\right)\sqrt{\sin\frac{\theta}{2}}}{\beta^4} = \frac{K_1}{\beta^4}$$

Formula 3

$$K_2 = \frac{2.6 \sin\frac{\theta}{2}\left(1-\beta^2\right)^2}{\beta^4} = \frac{K_1}{\beta^4}$$

Formula 4

$$K_2 = \frac{\left(1-\beta^2\right)^2}{\beta^4} = \frac{K_1}{\beta^4}$$

Formula 5

$$K_2 = \frac{K_1}{\beta^4} + \text{Formula 1} + \text{Formula 3}$$

$$K_2 = \frac{K_1 + \sin\frac{\theta}{2}\left[0.8\left(1-\beta^2\right) + 2.6\left(1-\beta^2\right)^2\right]}{\beta^4}$$

Formula 6

$$K_2 = \frac{K_1}{\beta^4} + \text{Formula 2} + \text{Formula 4}$$

$$K_2 = \frac{K_1 + 0.5\sqrt{\sin\frac{\theta}{2}}\left(1-\beta^2\right) + \left(1-\beta^2\right)^2}{\beta^4}$$

$$K_2 = \frac{K_1}{\beta^4} + \beta\left(\text{Formula 2} + \text{Formula 4}\right) \text{ when } \theta = 180^\circ$$

$$K_2 = \frac{K_1 + \beta\left[0.5\left(1-\beta^2\right) + \left(1-\beta^2\right)^2\right]}{\beta^4}$$

$$\beta = \frac{d_1}{d_2}$$

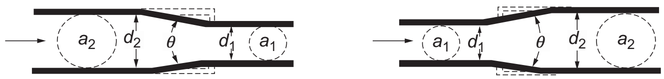
$$\beta^2 = \left(\frac{d_1}{d_2}\right)^2 = \frac{a_1}{a_2}$$

Subscript 1 defines dimensions and coefficients with reference to the smaller diameter.

Subscript 2 refers to the larger diameter.

*Use K furnished by valve or fitting supplier when available

Sudden and gradual contraction **Sudden and gradual enlargement**



If: $\theta < 45°$ .... K_2 = Formula 1
$45° < \theta < 180°$ .... K_2 = Formula 2

If: $\theta < 45°$ .... K_2 = Formula 3
$45° < \theta < 180°$ .... K_2 = Formula 4

Representative resistance coefficients (K) for valves and fittings (courtesy of Crane Co.)

NOMENCLATURE

Unless otherwise stated, all symbols used in this book are defined as follows:

$\boldsymbol{A}$	cross-sectional area of pipe or orifice, in m^2
$\boldsymbol{a}$	cross-sectional area of pipe or orifice, or flow area in valve, in mm^2
$\boldsymbol{B}$	rate of flow in barrels (42 US gallons) per hour
$\boldsymbol{C}$	flow coefficient for orifices and nozzles = discharge coefficient corrected for velocity of approach = $C_d/\sqrt{1-\beta^4}$
$\boldsymbol{C_d}$	discharge coefficient for orifices and nozzles
$\boldsymbol{C_v}$	flow coefficient for valves
$\boldsymbol{D}$	internal diameter of pipe, in m
$\boldsymbol{d}$	internal diameter of pipe, in mm
e	base of natural logarithm = 2.718
$\boldsymbol{f}$	friction factor in formula $h_L = f\, L\, v^2/D\ 2g_n$
$\boldsymbol{f_T}$	friction factor in zone of complete turbulence
$\boldsymbol{g_n}$	acceleration of gravity = 9.81 m/s
$\boldsymbol{H}$	total head, in m of fluid
$\boldsymbol{h}$	static pressure head existing at a point, in m of fluid
$\boldsymbol{h_L}$	loss of static pressure head due to fluid flow, in m of fluid
$\boldsymbol{h_w}$	static pressure head, in mm of water
$\boldsymbol{K}$	resistance coefficient or velocity head loss in the formula, $h_L = Kv^2/2g_n$
$\boldsymbol{L}$	length of pipe, in m

L/D	equivalent length of a resistance to flow, in pipe diameters
L_m	length of pipe, in km
M	molecular weight (molecular mass)
P	pressure, in N/m^2 (Pa) gauge
P'	pressure, in N/m^2 (Pa) absolute

(see page 1-5 for diagram showing relationship between gauge and absolute pressure)

p	pressure, in bars gauge
p'	pressure, in bars absolute
Q	rate of flow, in L/min
q	rate of flow, in m^3/s at flowing conditions
q'	rate of flow, in m^3/s at metric standard conditions (MSC)–1.013 25 bar absolute and 15°C
q'_d	rate of flow, in millions of m^3/day at MSC
q'_h	rate of flow, in m^3/hat MSC
q_m	rate of flow, in m^3/min at flowing conditions
q'_m	rate of flow, in m^3/min at MSC
R_o	universal gas constant = 8314 J/kg-mol/K
R	individual gas constant = R_o/M J/kg K (where M = molecular weight of the gas)
R_e	Reynolds number
R_H	hydraulic radius, in m
r_c	critical pressure ratio for compressible flow
S	specific gravity of liquids at specified temperature relative to water at standard temperature (15°C)—(relative density)
S_g	specific gravity of a gas relative to air = the ratio of the molecular weight of the gas to that of air (relative density)
T	absolute temperature, in K (273 + t)
t	temperature, in °C
$\overline{V}$	specific volume of fluid, in m^3/kg
V	mean velocity of flow, in m/min
V_a	volume, in m^3
v	mean velocity of flow, in m/s
v_s	sonic (or critical) velocity of flow of a gas, in m/s
W	rate of flow, in kg/h
w	rate of flow, in kg/s
w_a	mass, in kg
Y	net expansion factor for compressible flow through orifices, nozzles, or pipe
Z	potential head or elevation above reference level, in m

GREEK LETTERS

Beta

β	ratio of small to large diameter in orifices and nozzles, and contractions or enlargements in pipes

Gamma

γ	ratio of specific heat at constant pressure to specific heat at constant volume = c_p/c_v

Delta

Δ	differential between two points

Epsilon

ε	absolute roughness or effective height of pipe wall irregularities, in mm
Mu	
μ	dynamic (absolute) viscosity, in cP
μ'	dynamic viscosity, in Ns/m^2 (Pa s)
Nu	
ν	kinematic viscosity, in cSt
ν'	kinematic viscosity, m^3/s
Rho	
ρ	weight density of fluid, kg/m^3
ρ'	density of fluid, g/cm^3
Sigma	
Σ	summation
Theta	
θ	angle of convergence or divergence in enlargements or contractions in pipes

SUBSCRIPTS FOR DIAMETER

(1)	… defines smaller diameter
(2)	… defines larger diameter

SUBSCRIPTS FOR FLUID PROPERTY

(1)	… defines inlet (upstream) condition
(2)	… defines outlet (downstream) condition

Nomenclature as used in all equations shown (courtesy of Crane Co.)

CHAPTER

Pipe stress analysis and layout of hot and cold piping 19

19.1 WHAT IS STRESS?

Stress is defined as the force per unit area that acts on a material or the intensity of forces distributed over a given section:

The general formula of stress is as follows:

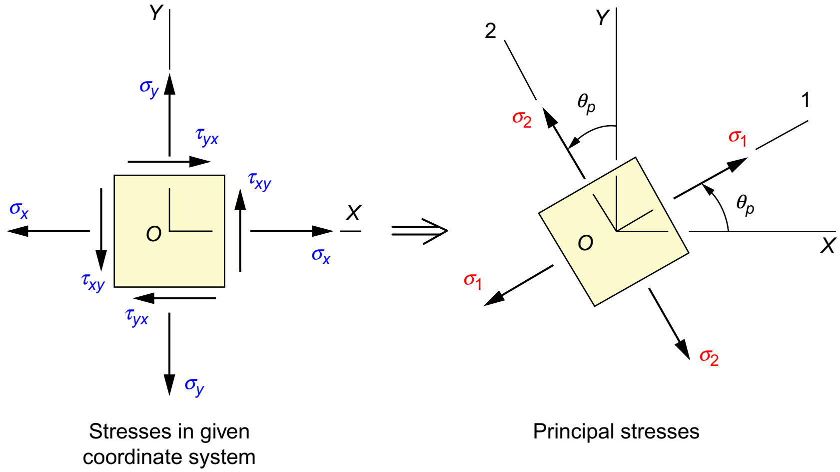
- stress = load/area

Stress (units) (SI)

- 1 N/m^2 = 1 Pa (Newton per square meter, pascal)

Stress (units) (English)

- 1 lbf/in^2 = 1 psi = 1/1000 ksi = 1/1000 kip/in^2



The three broad categories of stress are the following:

- **Tensile**

Tensile stress (stress/load) is the stress pertaining to tension or stretching.

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries.
https://doi.org/10.1016/B978-0-12-814653-8.00019-9

- **Compressive**

Compressive stress (stress/load) pertains to compression or squishing.

- **Shearing**

Shearing (stress/load) causes different parts of the body to slide past each other in opposite directions in a motion parallel to the direction of force application; it cannot be considered to be uniform.

AXIAL LOADING

The loading directed parallel to the longitudinal axis of the member is called axial loading.

Normal **stress** of a member under axial loading is given by the formula $\sigma = P/A$.

A uniform distribution of stresses in axial loading is only possible when the loading is centric.

CENTRIC LOADING

If the line of action of forces P and $\mathbf{P}'$ passes through the centroid of the considered section then it is called centric loading.

ECCENTRIC LOADING

Eccentric loading is when the loading is axial but the line of action is not collinear with the centroid of the considered section. The stress distribution is neither uniform nor symmetric, and an additional moment is created. The formulas for shearing stress, single shear, and double shear are as follows:

- Shearing stress formula = $T\_ave = P/A = F/A$.
- Single shear formula = $T\_ave = P/A = F/A$.
- Double shear formula = $T\_ave = P/A = F/2A$.
- Bearing surface, e.g., surface of contact for a bolt, pin, rivet, etc.
- Bolts, pins, and rivets exert forces along their surface of contact which is referred to as the bearing surface.

AXIAL LOADING: NORMAL STRESS

Axial loading occurs when the internal forces for an axially loaded member is ***normal*** to a section cut perpendicular to the member axis.

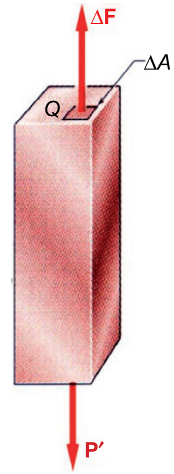
The force intensity on that section is defined as the normal stress:

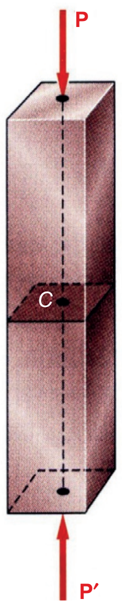
$$\sigma = \lim_{\Delta A \to 0} \frac{\Delta F}{\Delta A} \quad \sigma_{\text{ave}} = \frac{P}{A}$$

The normal stress at a particular point may not be equal to the average stress but the resultant of the stress distribution must satisfy the above relation.

The detailed distribution of stress is statically indeterminate, that is, cannot be found from statics alone.

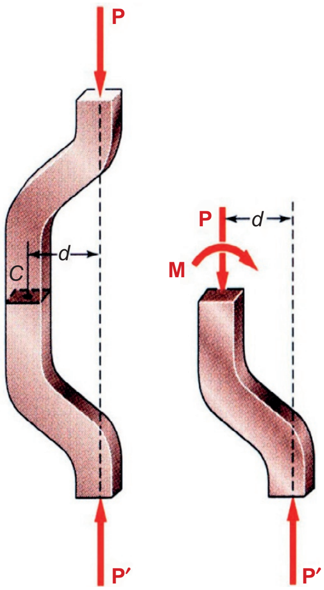
$$P = \sigma_{\text{ave}} A = \int dF = \int \sigma dA$$





CENTRIC & ECCENTRIC LOADING

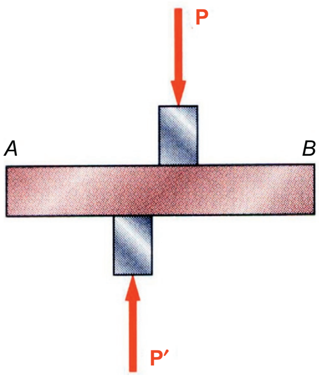
A uniform distribution of stress in a section infers that the line of action for the resultant of the internal forces passes through the centroid of the section.



A uniform distribution of stress is only possible if the concentrated loads on the end sections of two force members are applied at the section centroids. This is referred to as centric loading.

If a two-force member is **eccentrically loaded**, then the resultant of the stress distribution in a section must yield an axial force and a moment.

The stress distribution in eccentrically loaded members cannot be uniform or symmetric.



Shearing stress

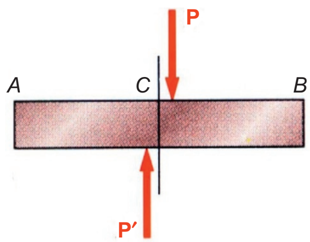
Forces **P** and **P′** are applied transversely to the member AB.

The corresponding internal forces act in the plane of section *C* and are called **shearing** forces.

The resultant of the internal shear force distribution is defined as the *shear* of the section and is equal to the load *P*.

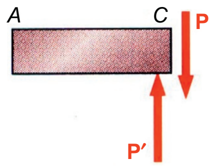
The corresponding average **shear stress** is

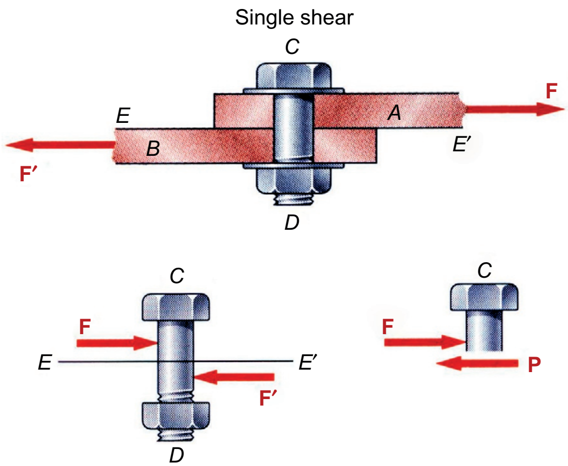
$$\tau_{ave} = \frac{P}{A}$$



Shear stress distribution varies from zero at the member surfaces to maximum values that may be much larger than the average value.

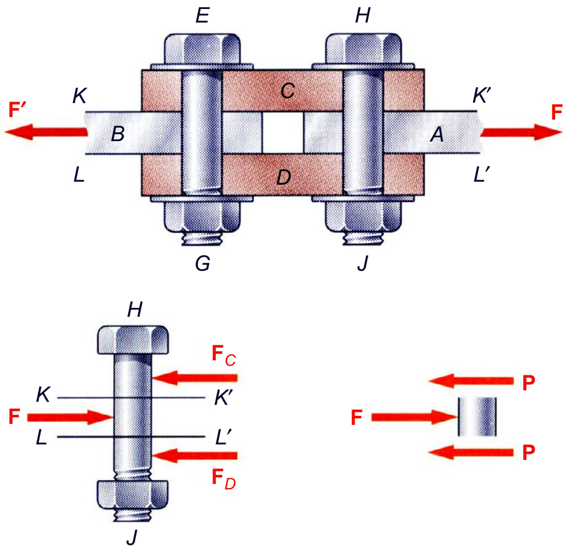
The **shear stress** distribution cannot be assumed to be uniform.



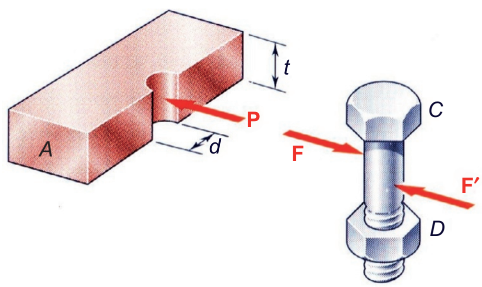


$$\tau_{\text{ave}} = \frac{P}{A} = \frac{F}{A}$$

Double shear



$$\tau_{\text{ave}} = \frac{P}{A} = \frac{F}{2A}$$

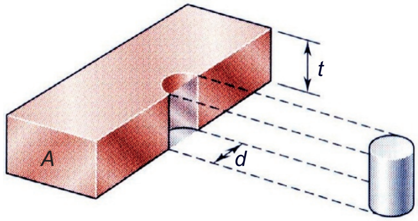


Bearing stress in connections

Bolts, rivets, and pins create stresses on the points of contact or bearing surfaces of the members they connect.

The resultant of the force distribution on the surface is equal and opposite to the force exerted on the pin.

Corresponding average force intensity is called the bearing stress,



19.2 CODES

HISTORY

- 1973—ANSI B31.3 Petroleum Refinery Piping Code
- 1974—ANSI B31.6 Chemical Plant Piping, merged to ANSI B31.3 Chemical Plant & Petroleum Refinery Piping
- 1996—Merged to include Cryogenic
- 1996—ASME Process Piping
- 1999—ASME B31.3 (metric)

ASME B31.3 (METRIC)

- **ft lb in^2**—is now kPa **(kilopascals)—**used for gauge pressure
- **Kips in^2**—is now MPa **(megapascals)—**used for stress
- **lbf**—is now **Newtons (N)**
- **Inch-pound force—**is now **Newton-meter (N-m)**
- **In—lbf**—is now **joules (J)** [for energy]
- **NPS** (nominal pipe size) is now **DN**
- **Psi** is now **PN**

PLANT LIFE

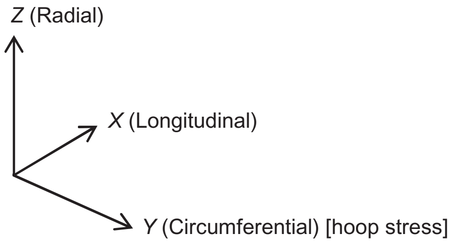
ASME B31.3 (Piping code)—code is based upon a plant life of 20–30 years
ASME B31.1 (Power code)—code is based upon a plant life of 40 years

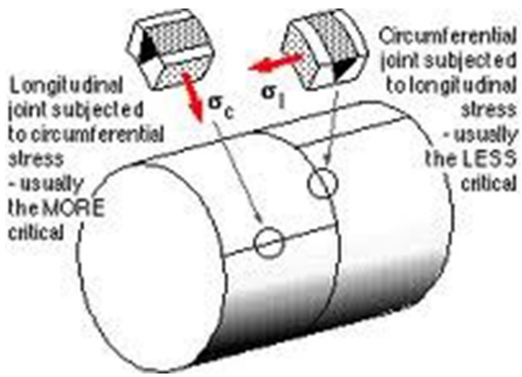
Safety Factors

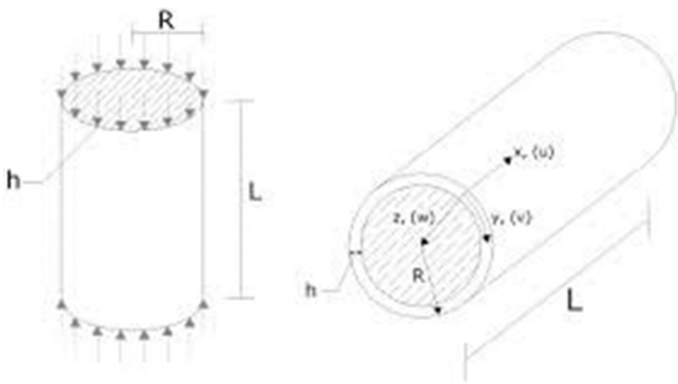
ASME B31.1 = 4 to 1
ASME B31.3 = 3 to 1

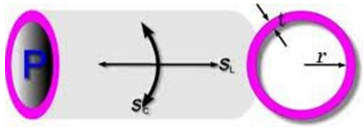
19.3 BASIC FORMULAS

PRINCIPAL AXIS AND STRESS



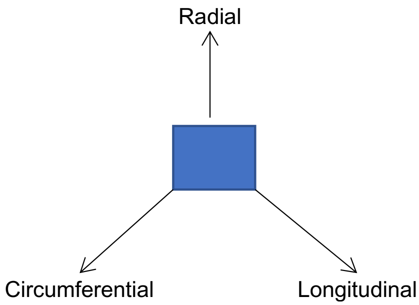


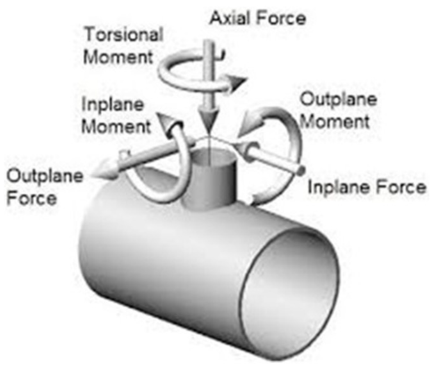


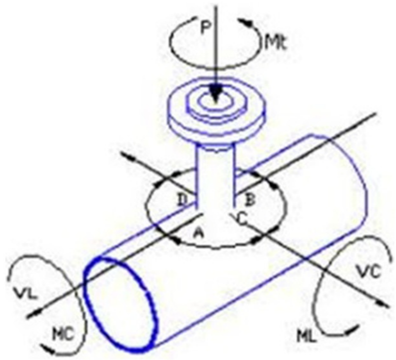


Stress is defined as the ratio of **force** to **area** or **moments divided by pipe section modulus**.

Force components are represented by **vectors**.







The resultant of the component of each force acting on the face of the cube, divided by the area of the cube is called **"principal stress."**

The **principal stress** that acts along the centerline of the pipe is called **"longitudinal principal stress."**

The stress is caused by longitudinal bending, axial force loading, or pressure.

RADIAL PRINCIPAL STRESS

The radial stress acts on a line from the center of the pipe radially through the pipe wall.

This is a compressive stress acting on the pipe ID caused by internal pressure, or a tensile stress caused by external vacuum pressure.

CIRCUMFERENTIAL PRINCIPAL STRESS

Also called **"Hoop Stress"** or **"Tangential Stress"** it acts on a line perpendicular to the "longitudinal "and the "radial stress;" this stress attempts to separate the pipe wall in the circumferential direction. This stress is caused by internal pressure.

When two or more "principal stresses" act at a point on a pipe, shear stress will be generated. One example of shear stress would be a pipe support where a "radial stress" caused by the supporting member acts in combination with the "longitudinal bending" caused by the pipe overhang.

THE MAXIMUM PRINCIPAL STRESS FAILURE THEORY

It states that when any one of the three mutually perpendicular "principal stresses" exceed the yield strength of the material at temperature, failure will occur.

An example:

Calculate the principal stresses in a DN350, 9.5 mm (NPS 14″, wt. 0.375″) operating at 8275 kpa (1200 psig) internal pressure.

Solution:

$$\frac{\text{Longitudinal Principal Stress (LPS)}}{[\text{LPS} = \text{PD}]}$$

$$4T$$

$$\text{Metric}: \text{LPS} = \frac{8275 \times 350}{4 \times 9.5} = 76\,\text{MPa}$$

$$\text{Imperial}: \text{LPS} = \frac{1200 \times 14}{4 \times 0.375} = 11{,}200\,\text{psi}$$

CIRCUMFERENTIAL PRINCIPAL STRESS

Formula:

$$\text{CPS} = \frac{P \times D}{2 \times T}$$

$$\text{Metric}: \text{CPS} = \frac{8275 \times 355.6}{2 \times 9.5 \times 10^3} = 155\,\text{MPa}$$

$$\text{imperial}: \text{CPS} = \frac{1200 \times 14}{2 \times 0.375} = 22{,}400\,\text{psi}$$

RADIAL PRINCIPAL STRESS (RPS)

RPS = −8 MPa (metric) RPS = −1200 psi (imperial) − on the inside surface
RPS = 0 − on the outside surface of the pipe

Applying the "maximum principal stress failure theory" to this piping condition, the "circumferential principal stress" would be the only stress of any concern. To protect against failure a wall thickness must be selected that will produce a "hoop stress" that will be below the yield strength of the piping material at the temperature of the pressure condition.

The "maximum shear failure theory" is an arithmetic average of the largest minus the smallest "principal stress" (tension producing principal stresses is positive and compression principal stresses are negative).

We have already defined "shear stress" as two or more "principal stresses" acting on the same point on the pipe.

The example we used in the "maximum principal stress" definition can be used to explain the "maximum shear theory."

The three principal stresses acting at the same point in the previous example are as follows:

LPS = 76 MPa (11,200 psi)
CPS = 155 MPa (22,400 psi)
RPS = −8 MPa (−1200 psi) on the inside

The maximum shear for this example would be

$$\begin{aligned}\text{Maximum shear} &= \frac{\text{CPS} - \text{RPS}}{2}\\ &= \frac{155 - (-8)}{2}\\ &= 82\,\text{MPa}(\text{metric})\\ \text{or } & \frac{22{,}400 - (-1200)}{2}\\ &= 11{,}800\,\text{psi (imperial)}\end{aligned}$$

The "maximum shear failure theory" states that when the maximum shear stress exceeds one-half of the yield strength of the material at temperature, failure will occur.

In the example we have used here, this system will be safe as long as the yield strength at temperature is above 164 MPa (23,600 psi).

Refer to ASME B31.3 Table A-1, Basic Allowable Stresses in Tension for Metals.

CALCULATING PIPE WALL THICKNESS

Factors that affect the pipe wall thickness requirement are:

- maximum working pressures
- maximum working temperatures

- chemical properties of the fluid
- the fluid velocity
- the pipe material and grade
- the safety factor or code design application

If there are no codes or standards that specifically apply to the oil and gas production facilities, the design engineer may select one of the industry codes or standards as the basis of design. The design and operation of gathering, transmission, and distribution pipeline systems are usually governed by codes, standards, and regulations. The engineer must verify whether the particular country in which the project is located has regulations, codes, and standards that apply to the facility.

The **basic formula** for determining pipe wall thickness is the general hoop stress formula for thin-walled cylinders, which is stated as:

$$t = \frac{Pd_o}{2(H_S + P)}$$

where H_S = hoop stress in the pipe wall, in psi [N/mm^2—metric]
t = pipe wall thickness, in. [mm—metric]
L = length of pipe, ft [mm—metric]
P = internal pressure of the pipe, psi [MPa—metric]
d_o = outside diameter of the pipe, in [mm—metric]

ANSI/ASME Standard B31.3 is a very stringent code with a high safety margin. The B31.3 wall-thickness calculation formula is stated as

$$t = t_e + t_{th} + \left[\frac{Pd_o}{2(SE + PY)}\right]\left[\frac{100}{100 - T_{ol}}\right]$$

where t = minimum design wall thickness, in.
t_e = corrosion allowance, in. [mm—metric]
t_{th} = thread or groove depth, in. [mm—metric] (Table 2)
P = allowable internal pressure in the pipe, psi (MPa—metric)
d_o = outside diameter of the pipe, in. [mm—metric]
S = allowable stress for the pipe, psi [N/mm^2—metric]
E = longitudinal weld-joint factor [1.0 seamless, 0.95 electric fusion weld, double butt, straight, or spiral seam APL 5L, 0.85 electric resistance weld (ERW), 0.60 furnace butt weld]
Y = derating factor (0.4 for ferrous materials operating below 900°F)
T_{ol} = manufacturers' allowable tolerance, % (12.5 pipe up to 20 in.—OD) (10 pipe > 20 in. OD, API5L)

BASIC FORMULAS

A piping system is said to be satisfactory from a flexibility standpoint if it satisfies the following equation:

$$\frac{DY}{(L-u)^2} \leq 0.03$$

where D = nominal pipe size, in. (mm)
Y = resultant of movements and thermal expansion to be absorbed by the pipe, in. (mm)
L = developed length of line axis, ft (m)
u = anchor distance (length of straight-line joining anchors) ft (m)

If the quantity $DY/(L-u)^2$ is less than or equal to 0.03, then the system is considered to have adequate flexibility.

If the quantity is greater than 0.03, then further analysis is required.

If the system complies with the above formula it may still not be acceptable if the terminal reactions at the anchors exceed the allowable limits.

So, the formula is the starting point possibly for a further analysis.

19.4 QUICK CHECK FORMULAS

It is important to provide adequate flexibility in piping systems by using loops or other configurations. Sometimes space or cost is prohibitive and movement must be absorbed by expansion joints such as between the bellows.

Piping flexibility should always be achieved with the minimum number of anchors and guides as is feasible.

Axial expansion joints must be guided on each side and anchored at the end of the pipe runs to withstand hydrostatic testing thrust.

U-type loops must be anchored on both sides of the pipe run to be able to work.

Lines which are to be purged by steam or hot gas must be checked to make sure that they will be adequately flexible during the purging operation.

Closed relief systems and hot blowdown or pump-out systems must also be carefully thought out.

The temperature in startup lines can often surpass the operating temperatures, so this must also be allowed for.

Exchanger bypasses must also be looked at, as they may still be cold while the inlet and outlet lines are already hot, and this would result in excessive stresses.

Therefore, it is mandatory to review the piping system at its worst condition such as startup or when a hot line will be feeding into a cold tower or vice versa.

Sometimes small branch sizes from large headers such as steam are provided with unnecessary and expensive expansion loops and anchors. Every effort must be provided by the engineer and designer to make sure the branches can withstand the header expansion.

Placing an anchor near the center of the pipe run can be used to direct the header expansion by forcing 50% of the expansion to either side of and away from the anchor. This distributes expansion along the header which helps to simplify branch flexibility.

The quick check method of flexibility analysis is used to determine if a piping system is adequately flexible without the formal calculations required such as Caesar II stress analysis.

Usually if the system is within the quick check guidelines, then no further flexibility analysis is required.

Be aware that this method only addresses the line flexibility with regard to line expansion; it does not address forces on the anchor points or at equipment nozzles, which is a separate exercise. But the quick check method is a good starting point with which to address the flexibility of a piping layout. Let us look at some quick check methods. For this, we must know the following:

- Location of anchor points (if not known, make an assumption)
- Design pressures, design temperatures, expansion coefficients, branch, or equipment restraints

COEFFICIENTS FOR CARBON STEEL

Design	Temperature	*A*	Design Temperature		*A*
°F	°C		°F	°C	
150	65	0.4	600	315	2.2
200	93	0.6	700	371	2.5
300	149	1.0	800	427	2.8
400	204	1.4	900	482	2.95
500	260	1.8	1000	538	3.15

COEFFICIENT TABLE

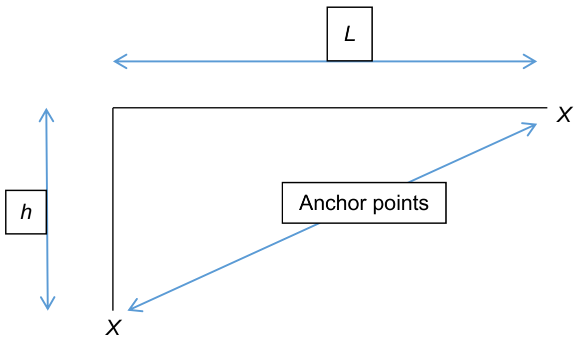
Special design conditions such as startup, cyclic operation, steam tracing, etc. must be known. When a pipe wall thickness differs from standard weight, a correction factor of rationing the moment of inertias must be applied:

$$\text{Minimum } h(\text{adjusted}) = \frac{\text{moment of inertia, pipe specified}}{\text{moment of inertia, std.wt.pipe} \times \text{minimum } h \text{ in the formula}}$$

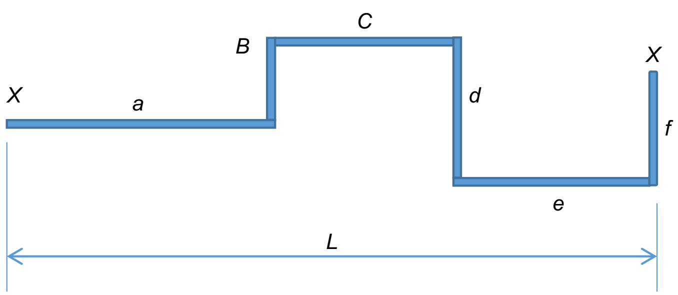
When anchor expansion adds to the thrust from leg L, a correction ratio of linear expansion must be applied:

$$\text{Minimum } h(\text{adjusted}) = \frac{\text{Anchor movement} + \text{leg } L \text{ movement}}{\text{leg } L \text{ movement} \times \text{minimum } h \text{ in the formula}}$$

L - shaped configuration:



$$\text{min } h = A \times Do$$
$$\text{min } h^2 = 0.0025 DoLT$$
$$\text{maximum } L = \frac{400(h)^2}{DoT}$$
$$\text{test for min } h = A \times Do$$

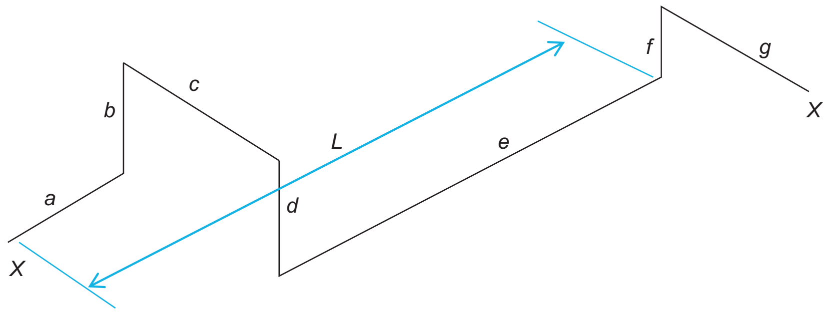


The *L-shaped* formulas can be adapted for more complex shapes in one or three planes.

In the shape above determine L the major length of line at right angles between the anchors: $a + c + e > b - d + f$ so $L = a + c + e$

$$\text{min } h = \sqrt{b2 + d2 + f2}$$

If the square root of the sum of the squares equals or exceeds, the required min h flexibility is sufficient.



Determine the distance between anchors in the horizontal plane at right angles and the vertical distance:

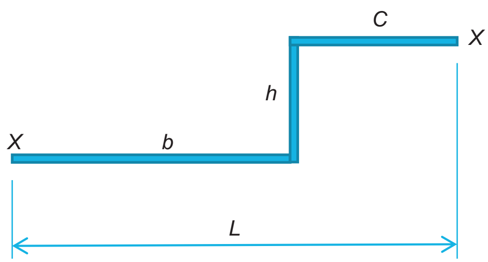
north-south distance $= a + e$
east-west distance $= c + g$
vertical distance $= b - d + f$

Determine L, the longest distance $a + e > c + g > b - d + f$ therefore $L = a + e$

L must be the largest of the three sums.

To determine minimum h, the shortest distance, the sum of legs $b + c + d + f + g$ must equal or exceed h. These are the legs at right angles to L.

Z SHAPES



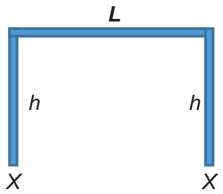
$$\text{Minimum } h^2 = 0.0025 DoLT$$

$$\text{Minimum } h = 0.05\sqrt{DoLT}$$

$$\text{Maximum } L = \frac{400(h)^2}{DoT}$$

$$\text{Test for minimum } h = \frac{B}{C} \geq 4 \quad L = B + C$$

U-SHAPES WITH EQUAL LEGS



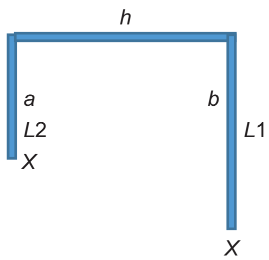
$$h^2 = 0.0016\,Do\,L\,T$$

$$h = 0.04\sqrt{Do\,L\,T}$$

$$\max L = \frac{625\,(h)^2}{Do\,T}$$

$$\text{to test for minimum } h = \frac{A \times Do}{1.25}$$

U-Shapes With Unequal Legs



for example:

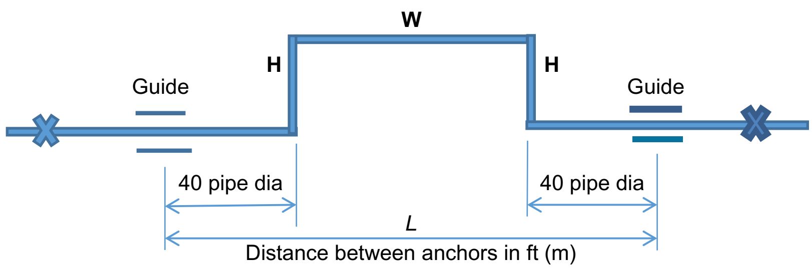
Pipe = 14″ sch 30
$Do = 14$
$T = 470° - 70° = 400°F\ (204°C)$
$L_1 = 25$ ft (7.6 m)
$L_2 = 5$ ft (1.5 m)

$$\begin{aligned}\min h &= 0.04\sqrt{DoLT} \\ &= 0.04\sqrt{14(25-5)400} \\ &= 0.04 \times 335 \\ &= 15\,\text{ft}(4.5\,\text{m})\end{aligned}$$

$$\text{test for minimum } h+L_2$$
$$=1.68\times 14$$
$$=23.5\,\text{ft}(7.2\,\text{m})$$

min L_1 also equals 23.5 ft (7.2 m), If min $h + L_2 = 15 + 5 = 20$ ft (6 m), then 15 ft (4.5 m) is too short, so use 20 ft as min h.

EXPANSION LOOPS



As an expansion loop expands, forces are transmitted to the two anchor points.

The force at each anchor: $F = C \times E \times Ip$

Maximum stress: $S = K \times E \times D$

QUICK CHECK FORMULAS

C = Constant obtained from values for constant C table

E = Expansion to be absorbed by the loop, in in. (mm) [this should be limited to 10″ (250 mm)]

Ip = Moment of inertia, in.^{4} (mm^4)

D = Outside diameter of the pipe in in.

K = Constant to be obtained from values for constant K table

	Length of *W* in Feet					
Length of *H* in feet	20	1.64	1.54	1.46	1.39	1.33
	19	1.92	1.80	1.70	1.61	1.56
	18	2.20	2.06	1.95	1.84	1.78
	17	2.47	2.31	2.19	2.08	2.00
	16	2.75	2.57	2.44	2.31	2.22
	15	3.03	2.83	2.68	2.55	2.44
	14	3.41	3.18	3.02	2.88	2.74
	13	4.02	3.76	3.54	3.36	3.20
	12	4.83	4.51	4.25	4.04	3.84
	11	5.86	5.45	5.51	4.89	4.66
	10	7.10	6.60	6.23	5.91	5.65
		10	15	20	25	30

	Length of *W* in Feet					
Length of *H* in feet	20	337	295	270	248	230
	19	361	318	290	267	246
	18	385	341	310	285	263
	17	409	364	330	304	279
	16	433	387	350	322	296
	15	457	410	372	340	313
	14	487	437	396	362	330
	13	528	475	428	391	361
	12	582	521	471	429	395
	11	647	577	520	474	436
	10	725	642	578	526	484
		10	15	20	25	30

Hot piping connected to strain sensitive equipment such as pumps, compressors, and turbines shall be closely reviewed for possible full stress analysis. Further stress analysis is required when

$$\frac{DY}{(L-u)^2} \leq 0.03$$

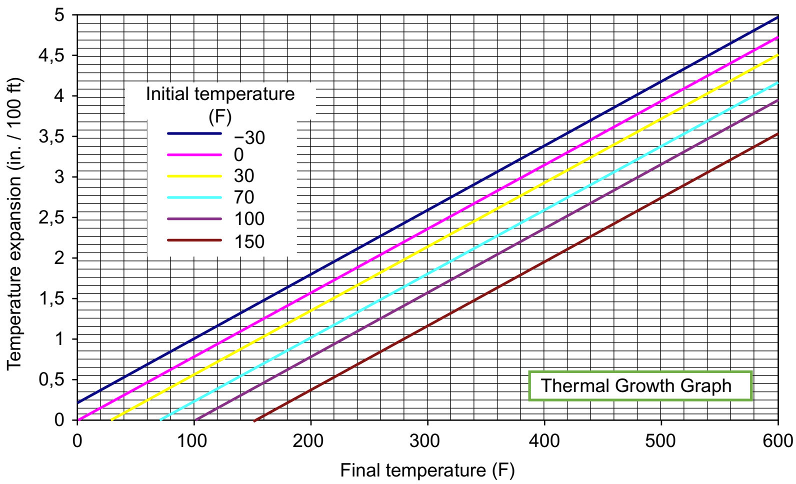
THERMAL GROWTH TABLE

Carbon steel (C.S.) = carbon-moly steels (through 3% Cr.)
Low chrome (L.Cr.) = intermediate alloy steels (5% Cr. Mo. through 9% Cr. Mo.)
High chrome (H.Cr.) = Straight chromium stainless steels: 12%, 17%, 27% Cr

Growth table—in./ft (mm/0.304 m)				
°F	°C	C.S. in./mm	L.Cr. in./mm	H.Cr. in./mm
100	38	0.003/0.076	0.003/0.076	0.003/0.076
200	93	0.010/0.254	0.009/0.228	0.009/0.228
300	149	0.018/0.457	0.017/0.432	0.016/0.406
400	204	0.027/0.685	0.025/0.635	0.023/0.584
500	260	0.036/0.914	0.034/0.863	0.031/0.787
600	316	0.046/1.168	0.042/1.066	0.039/0.991
700	371	0.056/1.422	0.051/1.295	0.047/1.193
800	427	0.067/1.702	0.061/1.549	0.056/1.422
900	482	0.078/1.981	0.071/1.803	0.065/1.651
1000	538	0.089/2.261	0.081/2.057	0.074/1.879

Continued

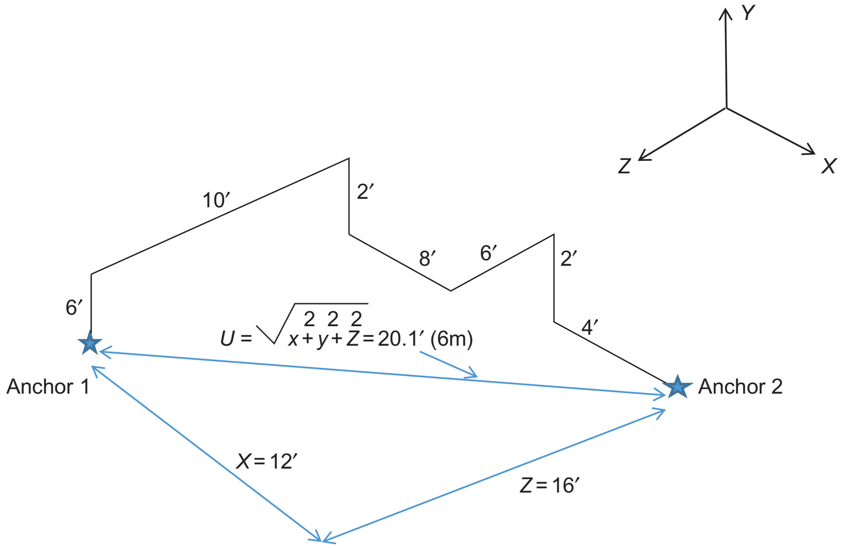
Growth table—in./ft (mm/0.304 m)				
°F	°C	C.S. in./mm	L.Cr. in./mm	H.Cr. in./mm
1100	593	0.100/2.540	0.091/2.311	0.083/2.108
1200	649	0.111/2.819	0.100/2.540	0.092/2.336
1300	704	0.122/3.098	0.111/2.819	0.101/2.565
1400	760	0.133/3.378	0.121/3.073	0.110/2.794



QUICK CHECK FORMULAS

Example:

D = nominal pipe size in in.
E = expansion to be absorbed, in in. ($E = Ue$)
L = developed length of line axis, in ft
U = anchor distance, in ft = length of straight line joining the anchors
e = coefficient of expansion (from expansion tables)
Pipe = 6″ sch 40 C.S., $D = 6$, design temperature = 400°F (204°C)



To solve the example:

Step 1: Establish the distance between anchors in plan and in ft (mm) and decimals of a foot (m)

y = vertical elevation difference = 6′ – 4′ = 2′ (difference in elevation between anchors 1 and 2)

x = total line length away from anchor 2 = 8′ + 4′ = 12′

z = total line length away from anchor 1 = 10′ + 6′ = 16′

Step 2: Determine length U, the straight length between anchors 1 and 2

$$\begin{aligned} U &= \sqrt{x^2 + u^2 + z^2} \\ &= \sqrt{12^2 + 2^2 + 16^2} \\ &= \sqrt{404} \\ &= 20.1(\text{say } 20') \end{aligned}$$

Step 3: Determine E

E = Ue (from coefficient of expansion tables e = 2.7 in. per 100 ft)

$$\begin{aligned} \text{so } e &= 0.027 \text{ in. per ft.} \\ E &= Ue \\ &= 20 \times 0.027 \\ &= 0.54''(\text{expansion}) \end{aligned}$$

Step 4: Determine the value of L, the total length of line:

L = 6 +10 +2+8 +6 +2 +4 = 38 ft

Step 5: Solve the formula which must be equal to or less than 0.03 or full stress analysis is required:

$$\frac{DY}{(L-u)^2} \leq 0.03$$

$$\frac{6 \times 0.54}{(38-20)^2} = \frac{3.24}{18^2}$$
$$= 3.24$$
$$0.324$$
$$= 0.01 \leq 0.03$$

Therefore, the configuration is satisfactory.

Piping connected to equipment nozzles:

When piping is connected to equipment nozzles which expand and contract due to temperature, the nozzle movement must be considered and added to expansion (E) calculations in the direction that they occur.

Referring back to our example, if *Anchor 1* was an equipment nozzle with an upward expansion of 0.375″, and in direction Z toward *Anchor 2* × 2″, the calculations must be modified.

Expansion must be figured for net lengths of X, Y, and Z, *and* the anchor movements applied.

Step 1: calculate expansion in the direction X:

$\Sigma X = 12 \times 0.027'' = 0.324''$ (since there is no anchor movement in direction X)
$\Sigma X = 0.324'' + 0 = 0.324''$

Step 2: calculate expansion in direction Y:

$\Sigma Y = 2 \times 0.027'' = 0.054''$ (since Anchor 1 is moving upward 0.375″)
$\Sigma Y = 0.054'' - 0.375'' = -0.321''$

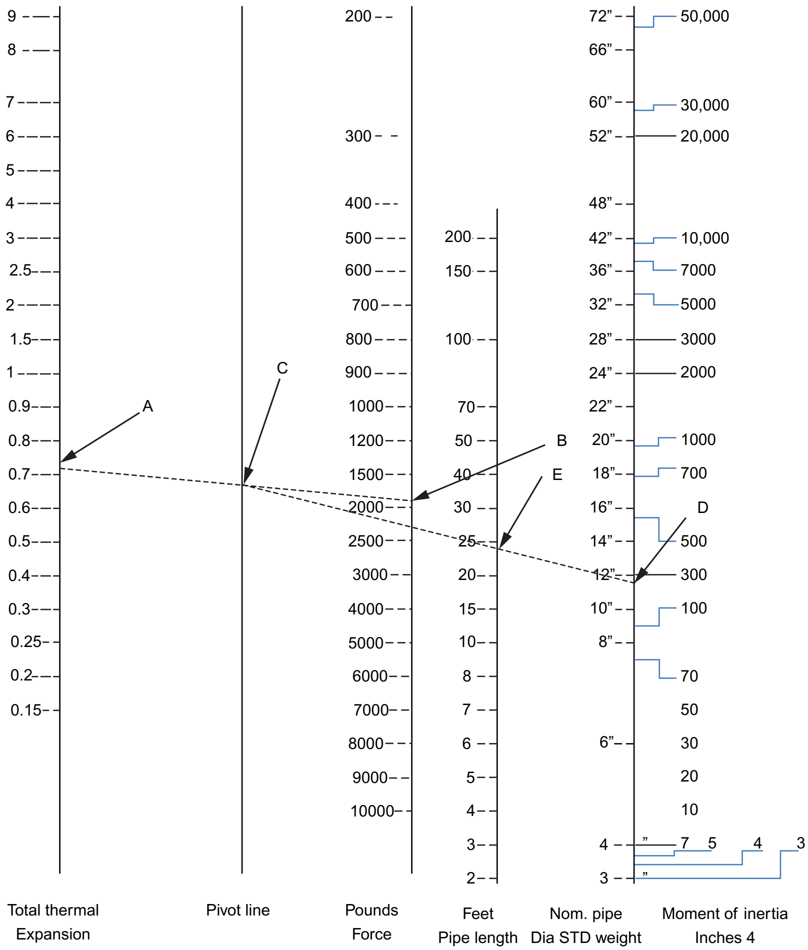
So use 0.321″ as this becomes the net anchor movement

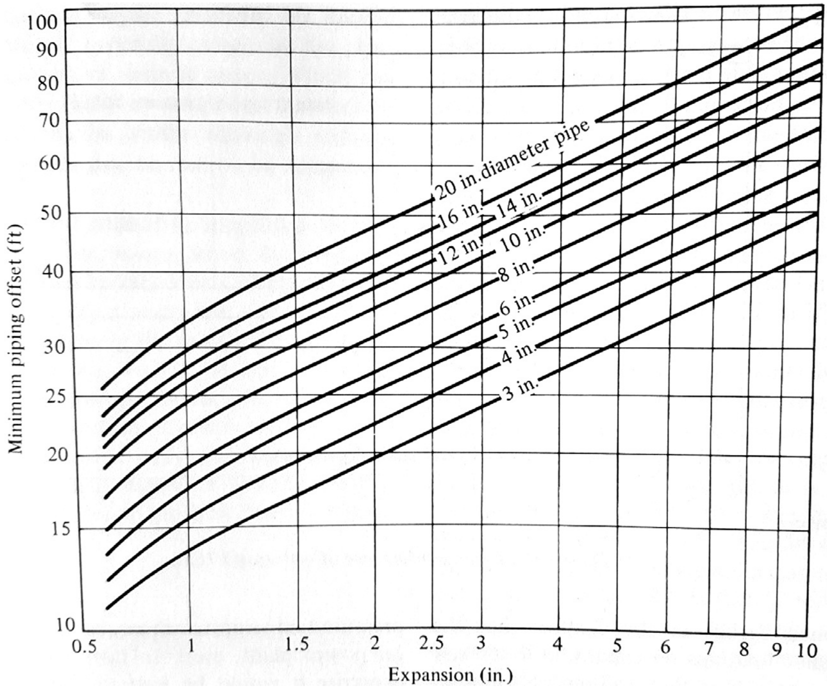
Step 3: calculate expansion in the direction Z

$\Sigma Z = 16 \times 0.027'' = 0.432''$ (since Anchor 1 is moving 2″ in the direction Z)
$\Sigma Z = 0.432'' + 2 = 2.432''$

19.5 NOMOGRAPHS

Chart for determining the absorbing leg on pump piping





Nomograph for determining the maximum offset required to provide flexibility for piping (based upon a maximum stress not exceeding 10,000 lb sq.in.)

19.6 APPLICATIONS

A typical piping system consists of a combination of pipes and various fitting components such as bends, Tees, O'lets, etc.

The plant piping systems are subjected to various types of loading due to weight, pressure, temperature, wind, water hammer, etc. causing possible failure modes, based on the type of loading, as plastic, rupture, fatigue, creep, etc. In addition, pipe exhibits different geometric characteristics at fittings which have notable effect on the flexibility of the piping system. This in turn has influence on stress concentration at fittings and the loads produced due to it.

Stress Intensification Factor (SIF): The behavior of a straight pipe and a bend under the externally applied bending moment is different. Straight pipe acts like a beam retaining the cross section as circular, whereas the bend takes an oval shape; due to ovalization of the bend the outer fiber comes closer to the neutral axis reducing the moment of inertial and subsequently the section modulus of the bend which in turn enhances the bending stress.

When performing flexibility calculations, the **SIF** must be taken into consideration. These factors are found in ASME Appendix D. The application of performing a **stress analysis** is vital for the criticality, performance, safety, reliability, robustness, operation, and economics of piping systems. Although as demonstrated in the previous slides, by the use of nomographs and quick check formulas (calculations) these methods are only as stated a quick check method. Usually providing the results of the quick check formulas are within the formula limits, then further analysis is not required. However, a majority of systems need further analysis:

This analysis is performed by using one of the proprietary stress programs available on the market.

The most widely used analysis program is **Caesar II**.

This program allows for the inputting of the required information based on the piping layout, and the results must be interpreted by a qualified stress engineer.

The program for **Caesar II** embodies **ASME** code.

When using Plant Design software programs such as **PDS, SmartPlant, and PDMS**, these have the ability to generate a stress neutral file, which can then be inputted directly into the Caesar II program for analysis of the line.

19.7 CRITICAL LINE LIST

A **critical line** list is a list of line numbers that are likely to need formal stress analysis calculations. These formal calculations are performed by a **qualified pipe stress engineer.** Whereas the quick check method was able to be performed by an engineer or designer, that has not been trained to use stress analysis software such as Caesar II, formal analysis must be performed by a qualified pipe stress engineer (usually, but not always a registered professional engineer).

The list of lines in the critical line list identifies the lines that have the greatest potential for flexibility problems in a layout.

The **stress engineer** normally supplies the **critical line list**.

As soon as an engineer or designer is satisfied that the piping arrangement is optimized, a stress isometric (or stress neutral file) is extracted from the 3D model.

The stress engineer will then analyze the system using the stress software; if changes in layout need to be made for flexibility or loadings, the marked up isometric will be returned to the responsible engineer or designer, to enable changes to be made in the 3D model or drawing (if 2D).

19.8 DESIGN PROCEDURES AND REQUIREMENTS

OVERSTRESSING OF PIPING COMPONENTS

It is obvious that the aim of a good piping layout is not to overstress the system.

Many forces act on a pipe including its own weight, thermal growth, wind, vibration, acoustic resonance, etc.

As any of these forces are applied, the piping begins to deflect (sag), grow, or shrink (cryogenic service).

The greater the forces on the pipe, the greater the deflection.

The greater the deflection, the higher the stresses on the pipe material.

When the stress in the pipe reaches its maximum limit, the deflection (deformation) becomes permanent.

Permanent deflection means that the pipe will not return to its original shape.

This is referred to as **"yielding,"** and the engineer must avoid this.

Therefore, to avoid this, the engineer designs the system by keeping the pipe stress below the limits described in the **ASME B31.3 code**.

OVERSTRESSING NOZZLES

Another problem that the stress engineer has to avoid is overstressing vessel and equipment nozzles.

The nozzle itself is normally not the problem, but it is the junction between the vessel wall and the nozzle.

As pipes cycle from cold to hot and back to cold again, it pushes on the nozzle.

Through many cycles during the pipe system use, this loading force can cause cracking in the vessel wall.

MECHANICAL EQUIPMENT

Rotating equipment such as pumps and compressors must have the piping system designed so as the forces acting on the nozzles are reduced to a minimum.

If the piping pushes against a pump or compressor nozzle with too much force, the force causes deflection on the nozzle, and excessive deflection at the nozzle can cause misalignment, which causes rapid wear on the bearings and other components.

The pump or compressor vendor defines the maximum allowable loads acceptable for their equipment.

API 610 specification for centrifugal pumps defines the maximum nozzle loadings.

CAUSES OF PIPE STRESS

Weight of the piping system

Weight caused by pipe sag, which puts stress onto the pipe materials and forces onto the equipment nozzles.

By identifying the proper pipe support and line spacing, and paying attention to any concentrated loads, most of the stress can be alleviated.

Thermal:

Pipe expansion when the line gets hot.

Pipe contraction when the line is under cold conditions (cryogenic).

An improperly stressed system will cause.

Deflection in the line which can cause possible deformation, misalignments that could result in nozzles to leak, bearing wear in pumps.

Possible pipe or vessel ruptures.

Ω A Correctly Designed, Engineered, and Stressed System is vital Ω.

So, we have finally come to the end of this book on "**Process Plant Layout, Detail Engineering, and Layout of Piping Systems**."

It was not the intention of this book to cover all aspects of plant layout and piping system design, which can only be obtained by years of study and experience.

However, for those starting out in the oil and gas, petrochemical, and facilities engineering fields and for those who, such as plant operators and young engineers and designers, want to enhance their knowledge from a practical perspective, this book will help.

The book therefore was an attempt to highlight the major principles and design points, along with some examples, that a piping engineer or designer would need to apply his trade.

There is NO substitute for experience, and the best engineers and designers, for the most part, are the ones who have enhanced the education that they have learned at the University or Technical College level, and added to this many years of in-plant and design office experience working along with their mentors and peers.

I hope this book has addressed a lot of the problems and examples that the engineer and designer will come across in the course of his or her career.

This book thus is a guide and an enhancement of already obtained, and possibly of some new knowledge and the ability to apply this knowledge on engineering projects.

I wish everyone who reads this book success in their careers and remember there is NO substitute for experience and knowledge.

Index

Note: Page numbers followed by *f* indicate figures and *t* indicate tables.

D

R

W

Y

The Engineer's Guide to Plant Layout and Piping Design for the Oil and Gas Industries

Geoff B. Barker IEng. MEI.

Learn how to design and build a process plant and its associated piping that is safe, operable, maintainable and economical

- Delivers practical guide to pipe supports, structures and hangers available in one go-to source
- Includes information on stress analysis basics, quick checks, pipe sizing and pressure drop
- Ensures compliance with the latest piping and plant layout codes and complies with worldwide risk management legislation and HSE

Due to a lack of structured training in academic and technical institutions, engineers and pipe designers today may understand various computer software programs but lack the fundamental understanding and implementation of how to lay out process plants and run piping correctly in the oil and gas industry. ***The Engineer's Guide to the Process Plant Layout and Piping Design for the Oil and Gas Industries*** fills this training void with a complete and practical understanding of the requirements and procedures for producing a safe, economical, operable, and maintainable process facility. Easy to understand for either the beginner or the novice to use as a reference, this guide includes critical standards, newer designs, practical checklists and rules of thumb. Starting with basic terms, codes, and basis for selection, the book focuses on each piece of equipment such as pumps, towers, underground piping, pipe sizes and supports, including selection. Rounding out with piping stress analysis and the daily needed calculations to use on the job, ***The Engineer's Guide to the Process Plant Layout and Piping Design for the Oil and Gas Industries*** gives pipeline engineers and plant managers a critical real-world reference to learn and understand the equipment so that they avoid costly mistakes.

- Parisher and Rhea, ***Pipe Drafting and Design***, 3rd Edition , Oct 2011, 9780123847003
- Moran , ***Process Plant Layout***, 2nd Edition, Nov 2016, 9780128033555
- Sutton, ***Plant Design and Operations***, 2nd Edition, June 2017, 9780128128831

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An imprint of Elsevier
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ISBN 978-0-12-814653-8
9 780128 146538