SECTION 4.0 ROTATING EQUIPMENT (DRIVEN ITEMS)

This section of the guidance notes covers a selection of the rotating equipment found on a typical offshore installation. These include :-

SECTION 4.1 CENTRIFUGAL GAS COMPRESSOR

CONTENTS

The target duty is the export of produced gas from a medium or large oil / gas field into a common manifold system. The back pressure in the manifold will vary depending on the total gas rate. The gas is a hydrocarbon mixture of variable molecular weight, including inert gases such as Nitrogen, and may contain corrosive/ toxic components such as Hydrogen Sulphide.

Figure 4,1 – 1 Barrel Type Process Gas Compressor

4.1.1 INTRODUCTION

- ***Gas Compressors are used to increase the pressure of a process gas, in order to drive it into a pipeline system to an onshore process plant, to use on the producing well as gas lift, to re-inject gas for reservoir pressure maintenance and for use as a fuel gas.***

- ***Turbo compressors are preferred for high mass flow systems because of their simplicity and reliability compared with screw or reciprocating compressors. In order to achieve the required pressure ratio, several compression stages may be required, in one or more casings. Each compression stage is carried out by a rotor in a matching diffuser.***

- ***This document focuses on the single shaft multi-stage "Barrel" design of compressor typically used for hydrocarbon gas compression in the oil & gas industry. Materials of construction must be mechanically capable, and compatible with process fluids anticipated throughout the field lifetime.***

- ***Mechanically linked compressors, working together with drive and support equipment, may be regarded as a single system for design and safety purposes.***

- ***The major hazards relate to the inventory of flammable gas that can be released if there is an equipment failure. Hazard assessment must relate to the complete package and not just the compressor body. The injury risk from a mechanical failure is relatively low, as the robust casing will retain parts. Hot / moving parts may still cause injury local to the machine. Most compressors have gas seals on moving drive shafts or piston rods. These are safety critical items when handling hazardous materials.***

It is often necessary to increase the pressure of a gas for processing, storage or transport reasons. There are two fundamentally different principles used to compress gases. Dynamic Compressors are continuous flow machines, they use rotating vanes or bladed discs to sequentially accelerate the gas (increasing its energy) then decelerate it (trading kinetic energy for increased pressure). This normally requires a number of stages, often within the same casing. Dynamic compressors always have an open gas route through the machine.

Positive Displacement Compressors are discontinuous flow machines, they induce a fixed volume of gas into a pocket, chamber or cylinder for compression. The size of this pocket is then reduced mechanically, compressing the gas. At the end of the compression cycle the pocket opens, discharging the high-pressure gas. Often only one or two stages of this compression process are required. There is never an open gas passage from delivery to suction (except for leakage through the clearances between moving parts.

Dynamic (as opposed to Positive Displacement) compressors have relatively few moving parts, low vibration levels and thus high intrinsic reliability. Hence they are preferred over other compressor types where they can be used effectively. Compressor selection is a complex and subjective process, with similar duties resulting in quite dis-similar compressors choices.

The materials of construction must be able to take the mechanical loads; in addition those parts in contact with the process gas must be chemically compatible. Non-metallic materials are often used in seals and valves.

It is common practice, for dynamic compressors, to mount multiple compression stages on the same shaft within a common casing. For pressure ratios above perhaps 10 : 1, and for

discharge pressures above perhaps 20 barg, a Barrel Type Multistage Centrifugal Compressor would be a reasonable selection.

Where a high-pressure ratio is required, different sizes of compressor, running at different speeds, may be linked to a single common driver. Gearbox(es) match the various shaft speeds.

To achieve reasonably practical shaft alignment and permit thermal expansion, flexible couplings are used between co-axial shafts.

Compressors require robust base-plates to carry shaft torques and piping loads without excessive distortion. This is particularly true offshore with the baseplate having to provide the necessary stiffness for alignment and dynamic stability on the offshore installation where the structure itself is too mobile.
Compressors require suitable piping, interstage vessels and coolers with associated control systems. Together with baseplate and driver this forms the "Compressor System".

The vast majority of compressors are shaft driven by a separate electric motor, gas turbine or diesel engine. Thus the compressor will require at least one shaft seal, which may have to contain hazardous gas.

The safety of compressors handling hazardous materials is dominated by their shaft sealing systems. These require appropriate design, maintenance and operator attention.

4.1.2 BACKGROUND & HISTORY

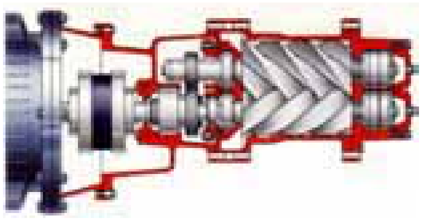
- ***Most early gas compressors were of reciprocating design; more recently even high-pressure applications can be met with high-speed multi stage centrifugal compressors.***
- ***"Barrel" casing design is preferred for high-pressure hazardous applications.***
- ***Other designs of compressor may be selected according to process duty and designer / user preference.***
- ***Typical modern process compressors have shaft speeds in the range 5000 - 10000 rev/minute and are tailor made to the required duty.***

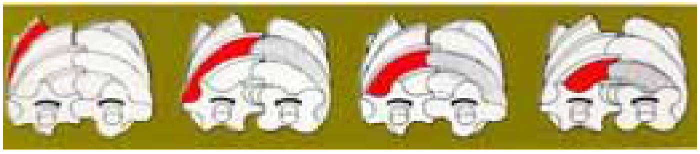
Gas compressors have been in use for well over a hundred years, turbo compressor development however has really only been in the second half of the twentieth century, using improved design and manufacturing methods. Early compressor design had a pressure casing with a horizontal split along the shaft, a split internal stator arrangement and up to about 9 stages on a single rotor shaft. For high pressures, several casings are operated in series, often at different shaft speeds. As system pressures have risen, it has become more and more difficult to build compressors with a reliable horizontal split joint. This is particularly so as discharge temperatures can exceed 200 C.

Recent design of high pressure compressors has favoured "barrel" casing design, where the pressure containment is a single cylindrical housing with end caps, containing a stator and rotor "cartridge". The end caps are often retained with a locking ring system and sealed with "O" rings, this being a much more secure and easily operated system than a long bolted joint. The cartridge is built up and loaded into the barrel, in this way a new cartridge can be fitted relatively quickly. Bearings and seals are built into the end caps.

Screw compressors may be used for lower capacity systems. Screws are a relatively recent design due to the very sophisticated manufacturing required.

Screw Compressor Principle





The type of multi-stage turbo compressor referred to as a "Bullgear" machine consists of several single stage compressors driven by an integral gearbox. The design lends itself to efficient compression, due to use of intercooling. However, the extensive use of coolers make the design less attractive for offshore applications. The design is also not well suited for gas turbine drives.

Typical modern process gas compressors have shaft speeds in the range 5000 – 10,000 rev/min, shaft power 1 - 30 MW per casing. The design and fabrication of the impellers is sophisticated, using state-of-the-art casting, machining and welding techniques. Although built from "standard" components, every machine is tailor made to the duty. For hydrocarbon machines the casings are typically of carbon steel, and the stator and rotor parts from carbon steel, stainless steel or special alloys. Trace elements in the range of process gases expected over the well life will dictate the choice of materials & coatings.

4.1.3 HAZARD ASSESSMENT

- ***The hazards associated with a gas compressor have to be considered over its complete operating/ maintenance cycle, not just full steady load operations. Mal-operation / excursions / drive system failures and emergencies must all be covered. The hazards must be seen in context with the installation as a whole, and be compared with alternative compression strategies. As an example, a single large turbo compressor may offer a much lower risk of gas leakage (fewer and more reliable process gas seals) than 4 smaller reciprocating compressors. It would, however, be much less flexible.***

4.1.3.1 Process Gas Hazards

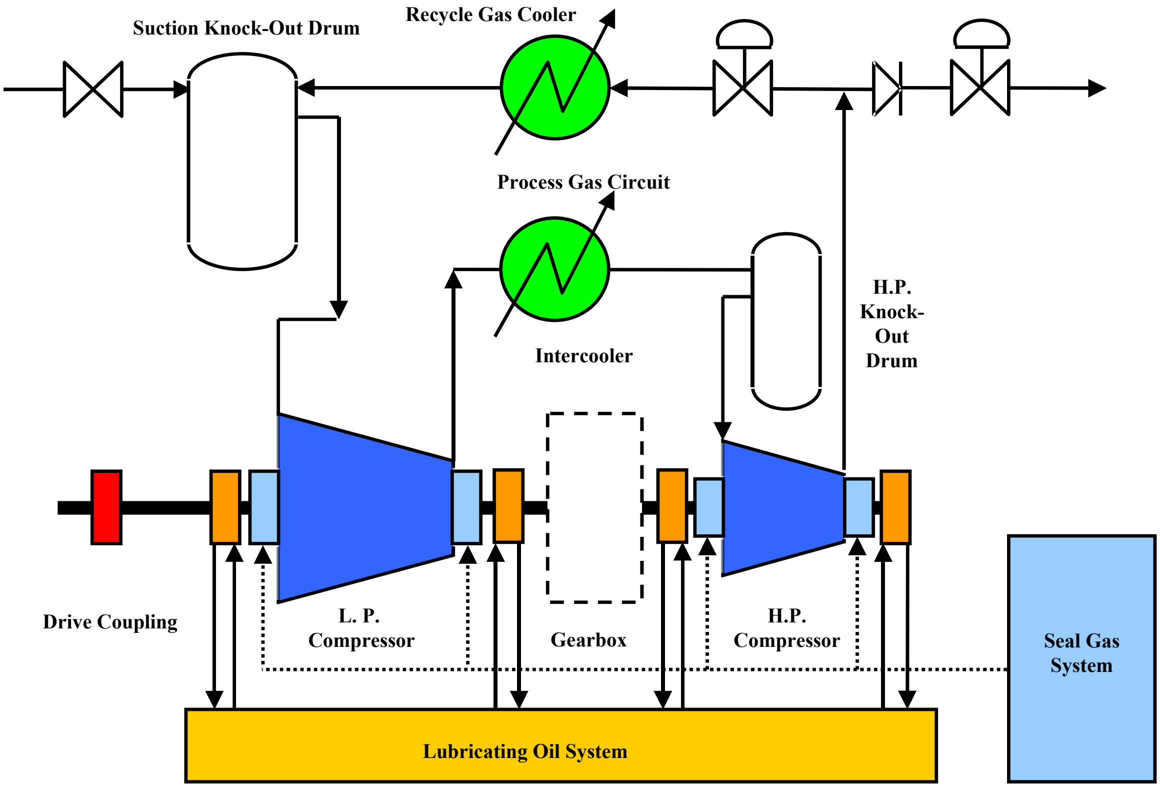


Figure 4,1 – 2 Process Diagram for Two Gas Compressors in Series

On most oil / gas installations the gas being handled will be a mixture of hydrocarbons and some inerts, of relatively low toxicity but posing an asphyxiation risk. Some gases containing hydrogen sulphides may be more toxic. Hence any release of gas which is diluted below the lower flammable limit may still pose a direct safety threat. Ideally, such releases may be detected by gas detectors and/ or by smell, and the fault repaired. Some devices e.g. valve glands, sample points and simple mechanical seals, release small quantities of gas during normal operation.

Toxic gases require care because of the immediate risk to people in the vicinity, who can be protected by good ventilation, and where necessary by the use of breathing apparatus.

Hydrocarbon gases pose a real safety threat if released in quantity / concentration sufficient to permit a fire / explosion. Because of the pressures / inventory involved in oil / gas installations, it has to be accepted that any leak in the pressure containment envelope is likely to lead to a large release. For this reason, designs with the least number of joints and connections are much preferred. All possible joints should be welded. Even small bore joints should be welded or flanged, not screwed. For these reasons the "barrel casing" design of centrifugal compressor is preferred over the horizontal split casing design, and particularly over reciprocating compressors.

In the event of a major release it will not be possible to get near to the machine to close the isolation valves. Thus strategically located emergency shut down valves are installed, to prevent venting of large capacity storage or pipe mains. Such isolation valves should permit closure from the control room, but should also close if their energising supply fails or is burnt through. The closure times of the isolation valves should consider both the requirements for effective isolation and the effects of pressure surge. Control valves should not be used as isolation valves because they do not close sufficiently tightly.

The process gas pipework within the main isolation valves should be treated as part of the machine system, particularly as part of it may well be supplied with the package. It may have been necessary to install bellows in the main process lines because of space constraints. A bellows failure can cause a major gas release. If the bellows are within the remote isolation valves, then exactly the same emergency isolation action will stop the release. Small-bore pipework is weaker than large bore, thus more vulnerable to damage. It is good practice to have robust primary isolation valves, at minimum 1" (25 mm) or 1 1/2" (40 mm) size, at the termination points of small bore harnesses. A failure can then be isolated quickly.

It must not be possible to bypass the main remote isolation valves, except as a planned activity, probably as part of commissioning or testing on non-flammable gas. No modification that bypasses the isolation valves should be accepted, without a clear understanding of the necessity of this arrangement, and the associated risks. There is likely to be a venting system, usually to flare, for purging or de-pressurising the compressor system. The system may hold a significant quantity as gas in casings, lines, interstage vessels and coolers. It is possible under some circumstances for gases from one system to be blown into another via common flare or vent lines. This is particularly the case when gas liquids are being handled, these can run down vent lines or cause blockages by freezing water in vent lines.

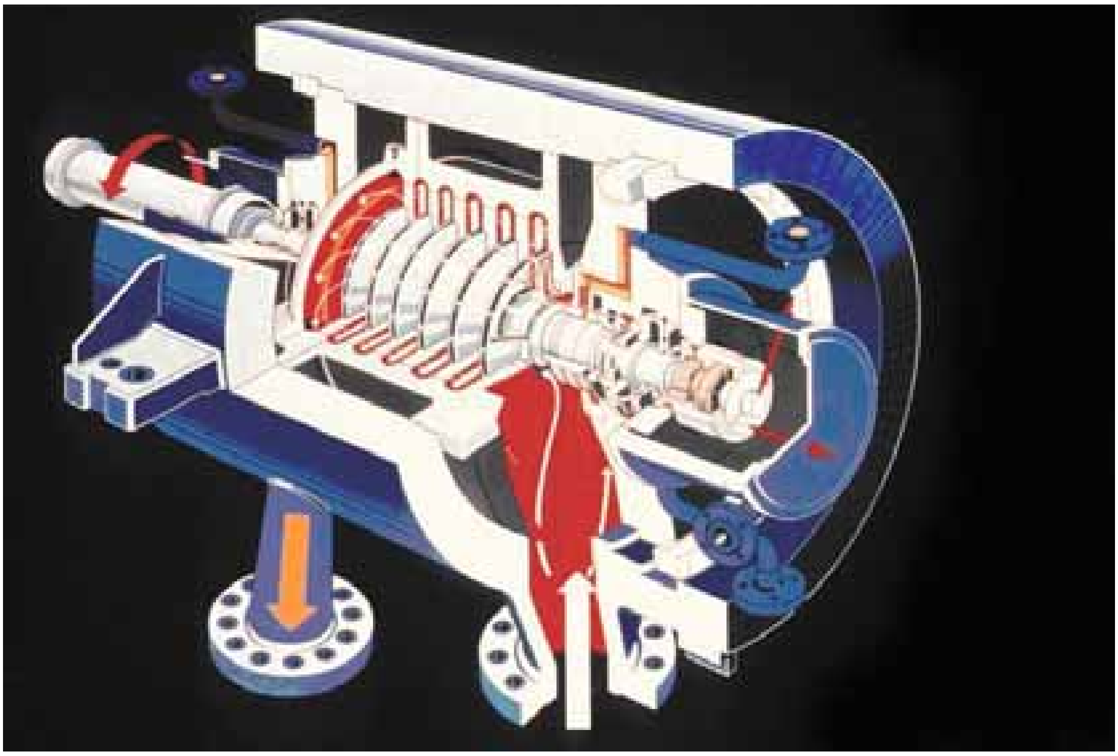


Figure 4,1 – 3 Barrel Compressor Function Diagram

Compressors inherently increase the superheat in the gas being processed. Hence any free moisture in the gas will impinge on the first stages, and be evaporated. Any tars or salts will be deposited on the blades. This will cause fouling. Similarly any solids e.g. dust or catalyst particles will potentially be deposited on the blades (stator or rotor). Where these build up / wash or wear off evenly, they might cause some loss in performance but no mechanical problems. Heavy build-ups that break off unevenly can throw the compressor out of balance. It is vital that the machine then be thoroughly cleaned. Residual unbalance indicates ineffective cleaning rather than a need to re-balance the rotor.

While compressors can tolerate sucking in a mist of clean liquid with no ill effects (this is sometimes used for interstage evaporative cooling), slugs of liquid can cause major damage. If there is any risk at all of liquid, the inlet piping must be designed to avoid liquid slugging. In all cases, the low points of inlet pipes require manual low point drains, for checks after overhaul / cleaning work. The drain valve should be of straight-through design e.g. plug or ball, permitting a wire or even a borescope to be used for a cleanliness check. The worst design is a long horizontal suction line, with a rising bend to the compressor. Liquid can collect in the line at low flow rates; this is swept up into a wave when flow is increased. A suction knockout pot as close as possible to the compressor, with drains, level detection, alarm and trip, is the normal solution. If liquid is rarely found, the drain valve may be blanked off.

4.1.3.2 Mechanical Hazards

The basic concept of a single shaft multistage gas compressor is extremely simple; there is only really one moving part. Hence such machines are inherently very reliable compared to reciprocating machines. The "barrel casing" design, chosen because of its superior pressure containment and thermal behaviour, is difficult to dismantle because rotor and stator parts have to be slotted onto the shaft. For most process duties, it is rarely necessary to dismantle the core

of the machine and it is good maintenance practice to remove a complete "cartridge" for overhaul ashore.

The overhauled cartridge can be quickly installed in the casing, without disturbing process pipework. Certain prescribed tests will be required before process re-start. The mechanical hazards from the compressor core in operation are virtually nil, even a major internal failure may have no external detectable effect. Process connections and compressor casing may be very hot or cold, lagging for personnel protection or heat retention may be required. Damaged or partly removed lagging may pose a personnel hazard or cause problems with differential thermal expansion.

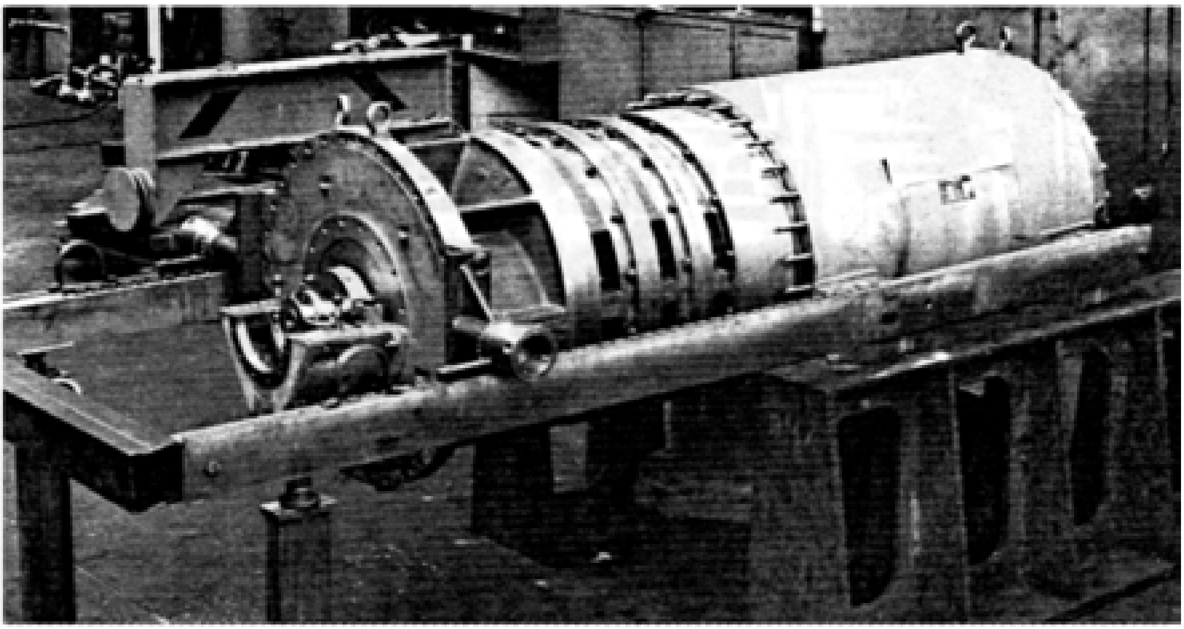


Figure 4,1 – 4   Barrel Compressor Cartridge Removal

Current designs of compressor require mechanical seals at both ends of the cartridge. These will be pressure balanced internally so that each seal is subject to compressor suction pressure (or in special cases an interstage pressure). Seals are dependent on a service fluid, usually a pressurised liquid or gas, this provides a cooling and lubricating film between the seal faces. Maintenance of totally clean service at the correct conditions is vital. Seal service pipes can be at very high pressure (up to 80 barg) and are usually small diameter, often with screwed connections. Protection of these pipes from mechanical load (e.g. being stood or leaned on) and vibration (through good routing and supporting) will reduce the failure risk. See seal details for consequences of loss of seal service. The fluid released from a failed pipe, though less hazardous than the process fluid, also may be toxic (e.g. ethylene glycol solution). Seals also require good shaft alignment and low vibration levels for optimum operation. Seals may operate hot or cold, but normally metal temperatures of 40 - 100 C are preferred, irrespective of the process temperature. There may be a short length of exposed shaft outboard of the seal, and this must be guarded.

Current designs (other than special designs using electro-magnetic bearings) have 2 outboard bearing assemblies. These are normally oil-lubricated, one assembly carries a radial bearing, the other carries radial and thrust. No moving parts are accessible, metal temperatures should not exceed 100 C. Although failed bearings can cause a fire, there is little risk of ejection of parts. Bearing monitoring (vibration, temperature, axial position) should detect a fault before major damage occurs.

Oil feed pipes to bearings is at relatively low pressures (3 - 5 barg) but can drip or spray oil if damaged. The oil may pose personnel risk (toxicity, spray in eyes, or as a slipping hazard) or catch fire from a hot surface. Compressor metal temperatures are unlikely to be high enough, but turbine combustion area or exhaust dust temperatures will be.

Mechanical shaft couplings pose a significant safety risk, particularly if neglected, or if the compressor is subject to serious misalignment or vibration. The potential for damage (and the amount of power wasted) within a coupling increases with the misalignment. A failed coupling can be thrown a very long way, normally at right angles to the shaft. With such robust equipment as Gas Turbine / Process Gas Compressor, shafts are unlikely to be displaced. Coupling guards, provided to avoid personnel contact with moving parts, cannot be expected to retain a thrown coupling. Vulnerable components (e.g. oil flexible pipes, cables, seal lines) ideally should not be located tangential to a major drive coupling. The abrupt loss of load and shaft inertia could provoke a dangerous overspeed event on the driving machine.

For details of Bearings, Seals, Shaft Couplings and related hazards see **Section 5** – Ancillary Systems & Equipment.

Overspeed

Where the compressor is driven by a variable speed device, such as a gas turbine, the speed compressor is must be protected from overspeed by the speed control system of the driver. In the event of coupling failure, this control is lost along with the drive. Any turbo-compressor can reach a dangerous over-speed in reverse if the discharge non-return valve does not close. For this reason, twin non-return valves are often used. It is good practice to use one simple non-return valve (self-closing, not a tight shut-off) in series with a power-operated trip valve (this may be the remote isolation valve). It is important that the volume of gas between the compressor discharge and the non-return valves is small. This minimises the energy available to create reverse flow.

Some gas compressors are fitted with energy recovery turbines (gas expanders). These may be separate machines or mounted on the end of the compressor shaft. In the event of a driver trip, or coupling failure, the recovery turbine could drive the compressor into overspeed. For this reason the recovery turbine should have a separate overspeed trip. These will probably link into the gas turbine overspeed trip, either system will trip the fuel and trip the recovery turbine inlet trip valve.

4.1.3.3 Operational / Consequential Hazards

An abrupt loss of the operation of the compressor may cause disruption of the upstream or downstream systems. This may result in systems being shut down, or load being transferred on to other compressors. The safety studies carried out as part of the safety case must ensure that there are no circumstances where a compressor failure might cause an unsafe condition e.g. over-pressurisation of a pipe header.

If a standby compressor is already connected up and under automatic control, load may be shed to it without operator intervention. This is likely to pose negligible risk. If operators feel obliged to bring a spare machine into service quickly, they may take potentially hazardous shortcuts, for example omitting gas purging. If the status of a machine under overhaul is in doubt, and this machine is brought back into service in a hurry, serious risks are being taken. This was one of the prime causes of the Piper Alpha fire.

A compressor can cause problems without actually failing. Examples are: -

- A fault in the load control system can result in rapid changes in flow or pressure; this disrupts upstream or downstream systems.

- A fault in the control system lets a process parameter drift outside the normal operating area. Trips and alarms normally protect against an individual value being unsatisfactory, but it is much more difficult to protect against a combination of changes that make a system inoperable or less efficient. It is up to the operators to remedy the situation.

- A change in the process gas composition, caused by a process upset or change in feedstock, can rapidly change the compressor discharge temperature or pressure.

- A compressor can run under or over speed, within the mechanically safe range, , the relief / vent system must be able to cope with excursions for conditions normally outside the process envelop and with the increased gas flow generated by the compressor running up to trip speed.

- An internal compressor problem, typically due to wear or fouling, can reduce compressor capacity and increase discharge temperature. This may lead to unpredictable surging at low speed / low flow. Instrument faults can cause similar effects. Centrifugal compressor surges are highly undesirable, are in general not violent enough to cause mechanical damage, provided only 2 or 3 cycles occur. Compressor protective systems are designed to identify the on set of surge conditions and. automatically introduce avoidance actions.

Where the installation is subject to significant motion, for example when under tow or during a storm, the motion may exceed the capabilities of the compressor. The unit may have to be shut down as a precautionary measure; otherwise mechanical damage may be caused. The most sensitive system is likely to be the lubrication oil system; movement or roll angles may interfere with oil distribution & return, or cause spurious level trips.

4.1.3.4 Maintenance / Access Hazards

The turbo-compressor will be located on the end of the gas turbine base frame, but not usually enclosed by the acoustic enclosure. The robust casing, often lagged, limits noise breakout. It is preferable to avoid putting the compressor inside an enclosure, as this would be a potential location for a gas build-up.

Access will be constrained by ancillary components that may have to be removed for maintenance purposes. It is necessary to provide access for specialist tools to remove the compressor bearings, seals and internal cartridge.

Compressor control panel and ancillaries may be located on the same skid, or adjacent, or in a control room.

4.1.4 OPERATING REQUIREMENTS

- ***Turbo-compressors are generally designed for long periods of steady operation, up to perhaps 3 years continuous service. Over-rapid start-ups & shutdowns can cause thermal expansion damage, particularly to seals.***

4.1.4.1 Continuous Duty

When selecting equipment for continuous operation, the buyer is looking for steady, efficient and reliable operation. This is the normal design case for barrel-casing turbo-compressors and will be what the vendor expects. Smooth, relatively slow start-ups and shutdowns will be the norm, ancillaries will normally be spared and can be overhauled with the compressor running. Sophisticated monitoring will give the best information to permit maintenance intervention to be well-planned and of the shortest possible duration. Chemical additives may be used to control fouling. Materials are selected for negligible corrosion in service.

4.1.4.2 Variable / Intermittent Load Duty

Turbo-compressors are tolerant of rapid load changes within the limits of the thermal expansion capabilities of the labyrinth seal system, Beyond these limits, seal damage will occur. Barrel casing machines are much more tolerant to these changes than split-casing machines. It is not permissible to operate beyond the package's design limits, even for a brief period. Turbo-compressors do not have a creep / temperature process, load limits are essentially to the design limits for material stress and bearing capability.

4.1.4.3 Emergency Duty

Turbo-compressors and the process systems they feed into are not normally suitable for being started and put on load in a few seconds. They are however suitable for continuous operation at lower speed / low mass flow pending rapid increase in speed / load to meet demand. This would be managed within the load control system without operator intervention.

4.1.5 MAINTENANCE REQUIREMENTS

- ***Barrel compressors are designed to be maintained by removal of the complete cartridge. Seals and bearings can be removed and replaced as assemblies. Control and isolation valves may be very large, hence requiring heavy lifting gear for maintenance.***

There is no effective access to the impellers or stator sections of a barrel casing compressor in situ. Hence the whole cartridge must be removed. This is a straightforward operation provided that the correct drawing frame is used. The cartridge will then be removed to a correctly equipped workshop for overhaul – probably onshore. There should be well-documented procedures associated with the manual handling / personal injury risk assessments associated with this type of operation. The risks to other personnel / damage to other equipment are probably lower than with a split-casing machine because casing halves and large pipework are not being lifted.

The labyrinth gas seals and mechanical seals can be maintained in situ, after removing bearings and parts of end caps. This is straightforward mechanical maintenance. However, poor quality work will reduce reliability of the seal arrangement. However, the monitoring systems for of internal seal performance will determine future maintenance requirements without compromising process gas sealing.

The bearings can be maintained in situ, and there are no special requirements or safety issues. The monitoring instrumentation will require be re-instating and checking for operation. The proximity sensors mounted within the bearing housings are in a fairly tough location and cannot be changed in service. Hence it may be prudent to change the sensors at an overhaul.

The control and remote isolation valves will be large and very heavy, often posing a difficult lifting problem. It is important that the full operation of these valves be tested before the plant is returned to service. It may be necessary to carry out in-service operating tests on valves to ensure their reliability.

4.1.5.1 Internal Corrosion

Most turbo-compressors operate wholly in the gas phase; thus corrosion is not a problem in service. In many cases the process gas is a superb de-greaser, thus during maintenance the exposed metal surfaces may be subject to rapid rust "blooming". This is unsightly, makes inspection difficult and will contaminate the system on re-commissioning. There is good reason to consider dry air purging and the use of air conditioning to avoid damp conditions.

The worst corrosion occurs if process deposits (salts, oxides) are exposed to damp air under poor ventilation conditions. This may occur if there is a failure that prevents a normal process clean out. The system is then opened for inspection, and left open while parts / resources are obtained. This can be avoided by proper cleaning / venting activities after the inspection, and even by applying corrosion inhibitors.

There is a special case for closed circuit systems e.g. process refrigeration, where the normal internal environment is so benign from the corrosion / wear point of view that opening up the system should be strongly resisted. All possible efforts should be made to monitor satisfactory operation by non-invasive means + oil & gas sampling. Should it be necessary to open up the

system, the least possible number of components should be opened, dry air purging should be used, strenuous efforts will be required to remove residual air and moisture before re-gassing.

4.1.6 CENTRIFUGAL GAS COMPRESSOR MAIN COMPONENTS

4.1.6.1 Barrel Casing

This is a one-piece pressure retaining housing in the form of a cylinder with nozzles for process connections. It will normally be centre-line supported. This gives a very robust design with very predictable stress levels, and can be of fabricated or cast construction. Two end covers, carrying the mechanical seals, complete the containment. Covers may be bolted on, or in some cases retained by proprietary ring joints.

4.1.6.2 Cartridge

The rotor and stator are built up in layers (quite a complex process) and slotted into the barrel. There are no pressure containment issues within the cartridge, it is common for stator parts to be cast but the rotor wheels have a high tip speed and are thus of sophisticated construction, and materials.

4.1.6.3 Mechanical Seals

It is a feature of these compressors that 2 mechanical seals are required, these are normally designed to operate with suction pressure only, to give axial pressure balance. Typically, double seals are used, serviced by nitrogen gas or seal oil to prevent major gas release on the failure or deterioration of the primary seal. For details of Mechanical Seals and related hazards see Sections 5.3.3 & 5.3.4.

4.1.6.4 Bearings

The shaft is supported by a radial bearing at each end and a single thrust bearing, normally at the non-drive end. Tilting pad bearings are common, these requiring a pumped lubricating oil supply. For details of Bearings and related hazards see Section 5.9.

4.1.6.5 Support Systems

Baseplate

This will normally be common with the base frame under the driver (and gearbox if fitted). Rigidity is vital to maintain alignment during temperature and load changes.

Lubrication System

Lubrication oil may be supplied from the driver (if a gas turbine), but the opposite arrangement is more likely. Where the gas generator has a dedicated system, the gas compressor lubrication system supports the second shaft (low-pressure power turbine) bearings, and power gearbox if fitted. The system will be mounted on or adjacent to the compressor baseplate, and designed to cope with start up, normal operation and run-down requirements.

Seal Gas System

Many modern machines have dry gas seals, the seal faces being lubricated and cooled by Nitrogen gas. This has the benefit of being simpler and taking less power than liquid supported

seals, but a continuous supply of gas is required, and seals will be damaged if the gas supply fails.

Seal Oil System

Where liquid supported mechanical seals are used, the seal liquid is usually compatible oil. Pressurised seal oil may be derived from the lubricating oil system, or be a self-contained system.

Suction Knock-out Pots

Depending on the gas being handled, liquid water or light hydrocarbons may condense out. Liquid droplets, or slugs in particular, can damage high-speed compressors. It is good practice to install an appropriately designed knockout pot immediately prior to the inlet of each compressor casing. Level detection and drainage are required.

Inter-cooler / After-cooler

For efficient compression, within limits defined by material properties, it is often necessary to cool the gas within the compressor system. This may cause additional condensation of liquids, with interstage cooling requiring an integral or associated liquid knock out and drainage system.

Recycle Valve

Centrifugal compressors have a limited range of acceptable suction flow. For start-up purposes, and to control capacity, discharge gas is returned to suction through a recycle valve. When a high proportion of the flow is recycled, it is important that the flow route includes a cooler. Either the normal after-cooler or a dedicated recycle cooler may be used.

For further information on Ancillaries and related hazards see Section 5 – Ancillary Systems & Equipment.

4.1.6.6 Control & Management Systems

The main control requirements will be dictated by the function that the compressor must perform. Flow control, suction pressure or discharge pressure control are common. Control may be done within a dedicated PLC or a plant DCS system. Parameters to be managed will include shaft speed, suction (or discharge) throttle valve control, and recycle valve control. Shaft speed control is achieved by a link to the gas turbine control.

Anti-surge control. When the process control calls for the compressor to operate with too low a suction flow, the anti-surge element of the control system will over-ride the process control and progressively open the recycle valve. If, due to fault conditions, this does not happen quickly enough, the compressor will enter "surge". This is characterised by violent oscillation of suction pressure and absorbed power. On detection of surge pulses, the compressor drive will trip and the recycle valve will be driven open rapidly.

Lubrication and seal service system controls. These are normally simple mechanical controls to maintain pressure, flow, and temperature of services. Loss of pressure will normally cause a compressor trip.

Process gas isolations are normally achieved using manual valves. This should be by "double block and bleed" principle, slip or spectacle plates should then be used for positive isolation. Automatic isolation and vent to flare on trip is quite possible. The use of power operated valves for process isolation requires additional care to ensure that the valve has actually closed (not

just the actuator) and that it cannot open again. This may require disconnecting linkages or air supply pipes. Air operated valves can open or close with tremendous force if air pipes are connected or disconnected inadvertently.

4.1.7 INTEGRATION ASPECTS

- ***Gas Compressors are specifically designed for a process duty; unexpected process conditions can cause rapid deterioration. This is unlikely to cause a direct hazard but could make maintenance tricky.***
- ***Mechanical integrity is very high, the weak area, as always, is the shaft seals.***
- ***Good alignment is well worth the effort, alignment errors can produce dynamic instability.***
- ***Relevant condition monitoring can assess the health of the unit and defer expensive and invasive maintenance.***
- ***Protective systems are fitted to prevent machine damage, and, more importantly, prevent a failure resulting in a gas release.***
- ***Modern compressors are fitted with very sophisticated bearings. With built in monitoring probes, a well-managed bearing system should have almost indefinite life.***
- ***The cooling requirement on a gas compressor itself is of the lubricating oil and is quite simple. The gas cooling can be more complex as it has to match process loads.***
- ***Sophisticated sealing systems are used. Continuous steady operation without thermal or pressure surge shocks will give the seals the best chance of a long life.***

4.1.7.1 Process Duties

Since turbo-compressors are designed for a chosen duty, it is important that the vendor be aware of, and understand, the full envelope of the duty. It is also important that any proposed extension of the operating envelope be explored with the vendor. Fortunately, changes in load resulting from changes in molecular weight or inlet pressure, will normally be limited by the normal machine controls. Problems will occur if changes are rapid, or if instruments are designed on the assumption of a fixed gas composition or inlet condition. The safety concerns relate to the possibility of over-pressurising the discharge line, or overloading the bearings.

Liquid ingestion, covered in Section 4.1.3.1 above, can cause damage or fouling. It can also cause increased load because of the increased mass flow. Some compressors can be washed to remove fouling, but this must be done with a carefully limited liquid flow to avoid over-loading. Liquid ingestion may also cause erosion of the first few compression wheels.

Gas recycle is often used for load control, because gas compressors will surge below a certain minimum flow. It is good practice to design such a system for continuous operation at full recycle. It must be recognised that this is a huge waste of energy, which can be reduced by variable speed, suction throttling and inlet guide vanes. It is necessary to remove the heat of

compression from the recycle gas, this may be by use of the normal in-line gas coolers, or by using dedicated recycle cooler(s). Any condensed liquids must be efficiently separated.

Intercoolers are often used to improve compression efficiency and limit discharge temperatures.

If the intercooler is ineffective, operating temperatures in the downstream machine will be excessive, Which could result in mechanical problems, such as seal rubs. The intercooler will usually condense liquid, if this is re-entrained, particularly as slugs, damage to the downstream machine blading could result. If the intercooler tubes leak, the downstream machine could be contaminated with salts from the cooling water.

4.1.7.2 Mechanical Integrity

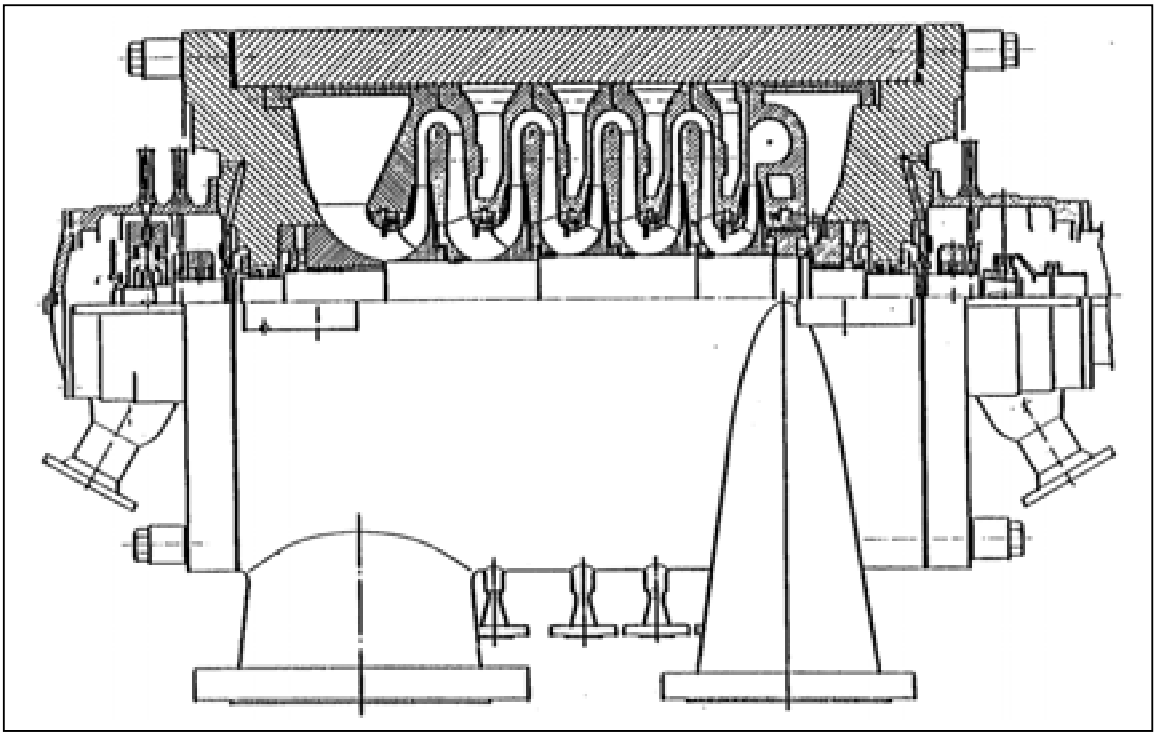


Figure 4,1 – 5 Part Cross Section of Barrel Compressor

The rotor of a single shaft turbo compressor is very simple; each impeller has a slightly different bore diameter to permit a good shrink fit on to matching shaft steps. Impellers are normally keyed to the shaft. Since the shaft is in one piece and is very well constrained, the likelihood of a failed shaft being torn out of the machine can be ignored.

The casing barrel and process connections are a single piece casting or welded fabrication; this is rated to the full design pressure. The only realistic potential for a major failure would be the loss of an end cover. These covers are retained either by a ring of bolts or by proprietary ring locks. In either case a failure could realistically only be caused by gross overpressure or by a common mode materials failure. An example of this might be the use of end cover studs made of poor material with cut rather than rolled threads.

The process pipe connections are flanged to the same standards of integrity as the rest of the process pipework. In some cases a welded –in-casing would be possible.

It has to be accepted that the mechanical seals are the weakest area of any turbo compressor. Double seals will be the norm, with monitoring of the service pressures and leakage (internal and external). Traditional designs of seal require a service pressure which is higher than the gas suction pressure, loss of this pressure causes the inboard seal to open, contaminating the service fluid with process gas. Provided that the outboard seal remains intact, no process gas leakage will occur. A shutdown will be required to remedy the situation. For clean process gases, certain designs of "pusher" seals can now tolerate loss of seal pressure. Note that this tolerance is for a limited time before overheating occurs. Either the service must be restored rapidly or the unit stopped pending repair. Many gas compressors now use dry gas seals, this avoids the use of a liquid service fluid, saving weight and complexity. Gas seals are not tolerant to a loss of gas supply pressure. Many mechanical seals are sensitive to direction of rotation.

4.1.7.3 Alignment

A gas compressor whose shafts are well aligned will run smoothly with minimum bearing loads.

Thermal expansion of the compressor, the driver and the baseplate cause the alignment to change. In addition, thermal and gas pressure loads are applied by the process pipework. The normal design arrangement is for the compressor to be supported at its centre-line, with the pipework supported to achieve flexibility. Provided that the thermal expansions are repeatable, the "cold" alignment is made with offsets for predicted expansion. This is a highly skilled job, preferably using laser alignment tools.

The centre line support is achieved by using support posts from the base frame to the machine casing. The machine is intended to expand radially & axially from its core, ensuring even expansion without bowing. Since the support posts are not exposed to process temperatures, they do not move significantly. To allow for the machine movement without high stresses, a set of sliding keys is normally used, between the support posts and the casing. Jamming of these keys can cause misalignment and seal rubs. Similarly, jamming of any moving pipe supports can cause problems. Some designs use intentionally flexible supports.

Any form of work which could constrain these movements, e.g. the drilling of holes to attach cable tray or fittings, should be assessed with care. The forces involved are huge and can tear out small-bore pipe that gets in the way.

As the shaft expands from the thrust bearing, which is located at one end of the machine, there will be differential expansion between the shaft and the stator. If this exceeds the axial clearance on the labyrinth seals (perhaps 1 mm) then the seals will be damaged. This effect can be controlled by warming up the machine at the specified rate. There is often a line or shoulder on the "free" end of the shaft which can be used as a check.

4.1.7.4 Condition Monitoring

Since turbo compressors are so well contained, their internal health can best be assessed by condition monitoring. The value of the process is usually so high as to justify quite elegant continuous monitoring. However, it is more important that whatever the installed system it works, is understood and is used properly.

Effective condition monitoring requires a benchmark measurement, trending, alert and action levels for each parameter. A single measurement in isolation gives little information.

Assuming that the process system in question is being controlled by a DCS system, the recording and trending of process parameters can provide information on compressor health. For example, efficiency change indicates fouling and discharge temperature may indicate labyrinth seal wear or cooler problems.

"Traditional" condition monitoring measures shaft position, vibration and temperature at bearings. Where this can be trended and compared with compressor duty, a good understanding can be gained of the compressor's health.

4.1.7.5 Protective Systems

Systems providing alarm only action should be subject to periodic testing, however delays to such tests, or known calibration errors, do not cause a direct safety risk and can be managed. Trending of the data prior to an alarm coming in can give valuable pre-warning; intelligent use of combined trends can indicate developing fault conditions. (E.g. drop in active thrust bearing temperature and rise in inactive temperature indicates a reversal of normal thrust loads - may be a blockage or leak in thrust balance gas passages).

The compressor must operate with closely defined parameters (for temperature, flow, pressure, vibration levels), these are measured and protective action automatically initiated when the machine exceeds them. The safety protective systems require tests and, must have a checked return to operation after test. Trip test procedures must be validated and adhered to. Trips may be disabled during machine start - ideally the measured values are recorded at high sample rates during a start, for examination should there be a problem. Also the enabling process must be validated - particularly on a new machine or after software / instrument modifications. Failure of a single trip should not lead to an unsafe condition - a problem is likely to be detected in several different ways, and the machine tripped before a dangerous condition is reached, though there may be some internal damage e.g. to a bearing.

Process Isolation. As referred to in Section 3.1, upstream and downstream process isolation valves should be tripped closed on a machine trip. In addition, there should be a self-acting non-return valve. These valves prevent reverse spinning, and minimise the extent of a process gas release from a damaged machine. Similarly if there is a process system trip, this may require the compressor to be tripped. If the trip is not safety-related, it may be delayed while vent / purge actions are completed.

Use of software trip systems. While it is recognised that the reliability, cost-effectiveness and sophistication of modern digital control systems mandates their use for the management control of complex plant equipment, the risk of common systems failure must be accepted. Key trips (e.g. seal pressure, oil pressure) may justify duplicate hard-wired trips. Changes to software trip sequences require rigorous change control procedures. This is true even of "vendor standard" upgrades, particularly on process systems which have probably been "tailored".

4.1.7.6 Bearings

Figure 4,1 – 6 Tilting Pad Thrust Bearing - Dismantled

The bearings in gas compressors are dependent on a continuous supply of oil for lubrication and, more importantly, cooling. Generally, oil must be pressure-fed prior to machine start, and continue to flow until the machine has fully stopped. This may take many minutes. Hence a selection of oil pumps, driven by AC power, machine shaft. Post-shutdown flow requirements are lower and can be met by a smaller pump, or a header tank. Oil quality in terms of grade, cleanliness, low moisture content,

temperature and adequate flow, are vital. Oil grades, even "equivalents", should not be mixed without draining the complete system.

Radial bearings are normally of the "tilting pad" type, particularly on higher power machines. These give a high load rating and stable shaft support. It is common practice to fit thermocouples in at least 1 pad per bearing - this gives accurate metal temperatures.

Thrust bearings will be double-sided tilting pad bearings. The bearing cannot carry anything like the total axial thrust generated by a compressor. The majority of the thrust is carried by internal gas pressure balance arrangements, normally a combination of impeller geometry and a thrust piston. To avoid instability, residual thrust is always in the same direction. This residual thrust is carried by the "active" thrust bearing, the thermocouples monitoring the thrust bearing pads (usually 2 in the active bearing, 1 in the inactive) should indicate a healthy but not excessive load. This load will change as the compressor duty load changes, but should be repeatable with the load. Excessive temperatures can indicate overload or restricted oil supply. Overload or reverse loading (shown by axial shaft probes and hot ***inactive*** thrust bearing) suggest problems with the gas pressure balance system. As this is fully internal, the compressor must be stripped down.

It is normal practice to fit proximity probes to monitor bearing behaviour. The thrust bearing wear can be monitored by these probes. Expert analysis of the vibration signature can detect rotodynamic, alignment and bearing problems. For details of Bearings and related hazards see **Section 5** – Ancillary Systems & Equipment.

4.1.7.7 Cooling

The main obvious cooling requirement on a gas compressor is the lubricating oil; this can be cooled against air or water. Loss of cooling effect normally results in a controlled trip with no safety implications. A cooler tube failure can be more subtle - air cooled tube failure can spray oil mist causing a fire risk, water tube failure can contaminate the oil causing rapid bearing failure. The cooler design should permit tube inspection / testing, corrosion resistant materials must be used, and gasketed water / oil joints avoided.

Conventional mechanical seals require cooling, usually of the circulating medium. Parts of the seal housings may be cooled to keep the seal temperatures well below the process temperatures.

The process gas coolers (inter, after, recycle) provide a cooling load dependent on process duty requirements. The cooling load may be massive (of the order of the compressor drive power) thus take a considerable part of the plant's available cooling capability. Any limitation in cooling will give higher than intended gas temperatures, reduced compressor efficiency. Provided that gas cooler inlet and outlet temperatures and pressures are available, loss in cooling performance can easily be detected and creates no hazard. Carrying out an energy balance across a cooler is notoriously difficult, cooling water flow measurement is seldom anything like accurate enough. For details of Cooling Systems and related hazards see Section 5 – Ancillary Systems & Equipment.

4.1.7.8 Sealing

Internal gas sealing

This is fairly simple; the use of labyrinth seals throughout is normal. Clearances will be checked and recorded at overhauls. Labyrinth seals are normally designed to have a sacrificial sleeve on the shaft, this is made of a soft & easily abraded alloy. A rubbing seal causes characteristic vibration effects that usually can be detected by the condition monitoring system. These

vibrations are often intermittent, caused during load or speed changes. For details of Labyrinth Seals and related hazards see Section 5.3.2.

External Gas Sealing by Mechanical Seals.

For details of Mechanical Seals and related hazards see Sections 5.3.3 & 5.3.4.

Bearing oil seals

For details of Oil Seals and related hazards see Section 5.3.5.

4.1.8 CONTROL

- ***The process control system will be set up to achieve the required duty at minimum practical energy usage.***
- ***Should effective control fail, the compressor may surge. A separate unit should detect this and trip the machine.***
- ***Support services will be linked by a simple permissive logic system.***
- ***Bearing monitoring will raise alarms first, followed by trip action if conditions worsen.***
- ***Control systems should be subject to a formal change control process.***
- ***A structured trip test programme is part of the appropriate maintenance strategy.***
- ***Significant changes in the process duty may require control system changes.***

The process control of the compressor will be set up to achieve target parameters in the gas flow, e.g. pressure, flow, at the least practical energy usage. This may involve recycle control, speed control (signal to gas turbine) and compressor inlet control. As gas flow through the compressor is reduced, the compressor will approach surge. This will be countered by altering Inlet Guide Vane geometry (where fitted) and by opening the recycle valve.

Should the surge control system fail to prevent surge, the surge pulses will be detected and trip the machine. Normally the recycle or anti-surge valve is rapidly driven open and the driver tripped. Surge conditions cause rapid and severe pressure & flow fluctuations, which can damage items like bellows. There is a form of high frequency surge found in certain systems at extreme off-design low flow conditions. The pulses are smaller and may not cause a trip. The immediate suction duct is subject to high gas temperatures - sufficient to burn paint.

There will be a simple logic control to ensure that services like oil and seal pressure are maintained. These must be established prior to start, and loss in e.g. oil pressure will raise an alarm and bring on a spare pump. Loss of such services will trip the compressor. Operating the compressor with such trips defeated is unsafe.

Bearing vibration, shaft position and bearing temperatures will raise alarms first, may then trip as conditions worsen. Tripping on vibration can be a headache as some bearing & sensor

systems are sensitive and prone to spurious trips. This is more the case for units with plain radial bearings, as the radial loads are well balanced hence the residual bearing loads are small. As a result, the shaft position within the bearing may be unstable, and load changes can cause shaft orbit changes or vibration. "Lobed" or "Lemon Shaped" bearings are a compromise solution that sometimes works, but the modern approach of fitting (more expensive) tilting pad bearings is the most reliable approach.

The trip and alarm facilities should be subject to a formal change control process, with clear definition of which (if any) changes may be made without manufacturer approval. Similarly the manufacturer's (or other) service engineer should not be permitted to change settings or software without formal record.

The operators require a clear understanding of which alarms/ trips are over-ridden during start, and why. Test procedures are required to validate that the important trips are re-enabled at the correct time. Formal testing and recording of alarm / trip tests, at intervals defined by or agreed with the manufacturer, are required. If tests are done with the machine on line, it must be recognised that the trip is disabled during the test, and that a partial test only is possible.

The control system will initially be configured to suit the intended duty of the machine. Should the duty change significantly, the control system may have to be re-configured to achieve effective results. Difficulties in controlling the recycle flow, or surge events, indicate a problem in this area.

4.1.9 ANCILLARIES

- ***Ancillary equipment should not pose any great hazard.***
- ***Twinned items may be serviced on line, with due care and appropriate instructions.***
- ***Lubricating oil backup systems should be tested off-line by simulating a trip.***

The range of ancillary equipment should not pose any great direct hazard, provided normal design, maintenance & inspection procedures are followed. Particularly during machine start / stop, ancillaries may start without warning. Where valve actuators and spindles are readily accessible, it may not be common practice or indeed practical to fully guard them. Consideration needs to be given to the relevant risk of a hand or arm trap while working in a confined space. Some form of shielding may be more appropriate than a full guard.

Where certain ancillaries e.g. filters, oil pumps, are twinned, it is possible to service or remove one unit while the compressor is on line. The operating instructions must cover the attendant risks of operating with one such unit unavailable, and the potential consequences of an incorrect changeover. One example is putting an oil filter on line without priming it, lubricating or control oil supply may be interrupted. Instructions and, if necessary, labels, may be required if changeover valves must be operated in a particular sequence, or can readily be mal-operated.

Some compressor installations have header tanks or pressure accumulators to provide lubricating oil for run-down in the event of complete power failure. These systems only work if the tank/ accumulator is full, the relevant valves are open, and the drive is tripped immediately the main oil supply is lost. The gravity oil flow is not sufficient for full speed / load operation. As live testing of such systems can cause significant machine damage, it is prudent to carry out simulated tests with the compressor stopped. If the oil supply lasts longer than the run-down

time, one can be confident of effective operation. It is very costly to wreck a compressor to prove that the run-down system did not work.

SECTION 4.2 SCREW COMPRESSOR – AIR SERVICE

CONTENTS

The target duty is the production of oil-free air for distribution to instruments and other clean services. While other types of compressors may be used, dry screw compressors are popular for moderate air flow rates.

4.2.1 INTRODUCTION

- ***Compressed Air is used widely as a support service, on and off shore. It is typically used to operate tools, machinery, control and isolation valves.***
- ***Control valves require the cleanest air, referred to as Instrument Air.***
- ***Tools operate on lower quality air, referred to as Service Air.***
- ***Other equipment may operate on either Instrument or Service Air, depending on availability and need.***
- ***Process Air and Combustion Air are usually required in much greater quantity, and are supplied separately.***
- ***Instrument Air can be supplied by several different types of compressor, packaged dry screw compressors are a popular choice.***
- ***Dry Screw Instrument Air compressors pose few hazards.***
- ***One specific hazard to be addressed is the potential for contamination of the air supply by toxic, corrosive or flammable materials.***

Compressed air is commonly used as a support service, on and off shore. It is used for tools, machinery, operation of control and isolation valves. Its particular benefits are :-

- It is relatively safe, compared with electricity, yet can supply quite powerful and compact tools.
- Only one supply pipe is required, making connection and disconnection simple.
- A damaged supply hose does not pose a fire or electrocution risk.
- Pneumatic cylinders provide a low cost means of operating simple machinery.
- Pneumatically powered valves move quickly and precisely to the required position.
- Fully pneumatic equipment can be used safely in the presence of flammable gases.
- Compressed air can be generated and stored on site.

Control valves have very fine nozzles and clearances in the pneumatic control box, thus only the cleanest possible air should be used. This is referred to as Instrument Air and is significantly cleaner than the ambient air in most industrial locations. In particular, the air is filtered, should contain no oil and very little water.

Air operated tools are much cruder and do not require finely filtered, and expensive, Instrument Air. They are supplied with Service Air, which is simply filtered, and may well contain oil and water. Many air tools require a trace of lubricating oil, which is added via a small device in the local air supply.

Figure 4,2 – 1 Packaged Instrument Air Compressor (Ghost Cut-Away View)
The above unit is water-cooled.

Other applications, e.g. pneumatic cylinders, can operate on either Instrument Air or Service Air. The selection is based on need, criticality, experience, local requirements, availability of supply.

Instrument and Service Air supplies are normally compressed locally, with some air receivers to smooth out demand peaks and permit compressor off-loading. Distribution is normally at 0 – 20 C above local ambient, at nominal pressure of between 6 and 12 barg. Interconnections between the two supplies should be controlled very carefully, as oil contamination in Instrument Air supplies is very difficult to remove.

Process Air and Combustion Air are normally completely separate, as these normally have much greater flows, and are at pressures defined by the process requirement.

Instrument Air can be supplied by a range of different compressor types, each with its own characteristics and available machine sizes. Packaged dry screw compressors are a popular choice for moderate size installations.

Dry screw compressors pose few direct safety hazards. They are noisy and have hot surfaces, but both of these issues are thoroughly dealt with in the packaging process. Unexpected loss of Instrument Air supply probably poses the greatest safety threat to an installation.

One specific hazard to be addressed in the system design is the issue of contamination of the air supply by toxic, corrosive or flammable materials. While it is possible for this to occur by ingestion via the compressor, it is more likely to occur via unintended back-flow into the distribution pipework. These risks cannot be assessed by the compressor manufacturer or package vendor, but are the responsibility of the operator. See **Section 2.7.3** for air system design issues.

4.2.2 BACKGROUND & HISTORY

- ***Early air compressors were of reciprocating design and were typically used to supply air to mining tools.***
- ***The developing chemical industry required control valves, these were pneumatically operated via pneumatic control devices.***
- ***These devices had very small moving parts and required exceptionally clean (for their day) air. "Dry" reciprocating compressors were developed to provide oil-free air.***
- ***As screw compressors were developed, oil-free versions were produced for gas and air compression.***
- ***Oil-free turbo compressors are available, but are too big for most instrument air demands.***

Air compressors have been in use for well over a hundred years, early designs were primarily of reciprocating design. Typical early uses were to operate drills in mines. Air quality was not too important, in fact a trace of oil helped to lubricate the drill.

As the chemical industry developed, it became necessary to replace manual operation of control valves with automatic control based on level, temperature etc. Prior to the availability of electronics, measuring instruments used tiny variable orifices to produce an air pressure control signal. Simple pneumatic analogue computers (long before the term was recognised) produced

a pneumatic signal to operate the control valves. These tiny parts required very clean air, without the oil that would otherwise tend to gum up the parts.

Special filters can remove most of the oil but traces eventually tend to get through, so compressor manufacturers developed air compressors which did not use lubricating oil in the cylinders. The machines were more complex and more maintenance-intensive, but supplied the required oil-free air. The term “dry” was used for the design, referring to the lack of oil in the cylinders. It was desirable to also remove all of the free water and most of the water vapour from the air, this is easier if the air is oil-free to start with.

Screw compressors require very special machine tools to produce the complex shapes of the rotors to the required accuracy. Once these tools were available, screw compressors became commonly available as air and gas compressors. They are generally less efficient than reciprocating compressors, but are much easier to install and maintain. Oil flooded and oil-free (“dry”) screw compressors are available to suit the different markets. Service air is normally provided by the cheaper and more rugged oil flooded designs.

Screw compressors have been developed in a range of sizes to suit most Instrument Air demands, particularly as good practice often calls for several compressors working in parallel to provide flexibility and reliability. Turbo compressors are available, giving superb reliability, but these are expensive and too big for most applications.

4.2.3 HAZARD ASSESSMENT

- ***The hazards associated with an air compressor have to be considered over its complete operating/ maintenance cycle, not just full steady load operation. Mal-operation / excursions / drive system failures and emergencies must all be covered. The hazards must be seen in context with the installation as a whole, and be compared with alternative compression strategies.***

4.2.3.1 Process Substance Containment Hazards – Air

Dry screw compressors produce oil-free air, which in itself poses little hazard. There are certain hazards from introducing compressed air into places which should not be pressurised, or which may already contain flammable gases. See **Section 2.7.3.5.1** for air system design issues.

It is possible for an air compressor to ingest flammable gases, and in compressing them produce a flammable mixture. This would then require a source of ignition, which is not normally present. The quantity of fuel involved would also be tiny. The risk associated with a Gas Turbine or a Combustion Air system would be much greater.

Compressed air can enhance combustion by increasing the pressure (e.g. materials which would smoulder in the open air will burn fiercely at 5 barg) or by fanning flames. It should never be confused with Oxygen, which can make normally non-flammable materials ignite, nor with Nitrogen, which kills by asphyxiation.

Oil flooded screw compressors, which are not preferred for Instrument Air compression but are commonly used for Service Air, use lubricating oil as an inherent part of the compression process. The compressor and local oil separator operate with a potentially explosive oil mist atmosphere at compressor discharge pressure. Lubrication failure, or an internal spark, can cause a small explosion and subsequent fire. The fuel is limited to the small oil reservoir. These compressors have special anti-static and temperature trip fittings, which must be maintained in working order and not tampered with.

4.2.3.2 Equipment Hazards

Screw compressors contain a pair of screw shaped rotors in close mesh with each other, or a single rotor with one or more meshing "gate" rotors. These rotating parts are contained within a reasonably robust cast housing. Speeds are modest and there is little potential for missiles. Smaller commercial packages may have belts drive, larger industrial unit typically have a fully enclosed drive housing. Drivers other than an electric motor will require an external drive with appropriate guarding.

Hence there is little mechanical risk from these machines. They produce very little vibration due to the inherent balance of the rotors, and require baseplate or foundations sufficient to carry the weight and maintain drive alignment. They are inherently very noisy, this is normally dealt with by packaging inside an integral acoustic enclosure.

Such mechanical risk as there is probably relates most to the potential for automatic starting, normally based on load. It is possible to safely open certain of the access covers without isolating the machine, but one must be aware of the potential for a start. The power must be isolated (not just switched to manual) prior to invasive maintenance.

4.2.3.3 Operational / Consequential Hazards

An abrupt loss of the operation of the compressor may cause loss of, or reduction in, the instrument air supply. This may result in systems being shut down, or control systems being sluggish. The safety studies carried out as part of the safety case must ensure that there are no circumstances where Instrument Air supply failure or limitation might cause an unsafe condition.

This risk is normally controlled by installing several compressors in parallel, with a load-sharing control system. A common mode failure, e.g. of the control system, could cause loss of the whole system.

Oil lubricated / oil flooded air compressors (normally Service Air) and Oil-free compressors must never be connected to the same pipe network without special precautions.

- Oil-free compressors are not always fitted with high discharge temperature trips. Under fault conditions, hot discharge air could ignite oil deposits laid down by oil-lubricated machines. These risks are higher with reciprocating compressors than screws.

- Clean Instrument Air pipework can be contaminated by oil from the Service Air compressor(s). Emergency cross-connection via oil removal filters might be acceptable. This is not a direct safety issue but is a major instrument reliability issue.

4.2.3.4 Maintenance / Access Hazards

Screw compressors are compact machines, the discharge pipework can run at up to 200 C, prior to the aftercooler. Most maintenance risks relate to sprains and injuries related to lifting in confined spaces. There should be no toxic materials present. The lubrication oil is high quality, and poses a small dermatitis risk.

4.2.4 OPERATING REQUIREMENTS

- ***Screw compressors can operate for long periods without major overhaul, but generally require minor servicing at more frequent intervals***

4.2.4.1 Single Compressor Operation

This is unusual in process plants as stops are required perhaps every 3 months, for servicing. Also there is no backup compressor in the event of a fault. If brief shutdowns are tolerable, this might be practical.

4.2.4.2 Standby Duty Only

Where compressed air is supplied from a central utility, it is sometimes considered appropriate to install a local standby machine. This is generally not an effective policy, since the type of cooling water or electrical power failure which can disrupt a central utility will probably also disrupt the local supply. It is more practical to install local air receivers, which are dedicated to maintaining essential duties only. It is entirely practical to install a temporary local machine to cover for maintenance or modifications to the air distribution system or utility supply.

4.2.4.3 Multiple Compressor Utility System

This is the practical installation, with two or more compatible compressors linked to a common system. To provide a very robust system, two compressor houses, well separated, and a ring main distribution system, will be used. In the event of an incident, control system segregation and automatic isolations will seal off damaged parts of the system, to main essential supplies for as long as possible. A sophisticated control system will switch compressors on and off, and alter their loads, to maintain a smooth supply without over-frequent switching. On shore, the cost of electricity drives users to switch off unwanted compressor capacity.

4.2.5 MAINTENANCE REQUIREMENTS

- ***Screw compressors are serviced in situ. Major overhauls comprise the replacement of compressor stage elements, which may then be refurbished under factory conditions.***

- ***Screw compressor elements are not intended to be rebuilt on site.***

Screw compressor servicing comprises cleaning, inspecting or replacing modular components in situ. The compressor elements themselves are factory-built precision units, while they can be dismantled under workshop conditions, it is unlikely that the skills or special tools required for a successful rebuild will be available on site. Any damage to the rotors normally requires new parts. Hence the normal practice is to fit new or factory refurbished elements after either a specified service life or based on condition monitoring trends.

Such replacement should restore the performance to “as-new” values.

The clearances inside compressor elements are very small, ingestion of dirt or scale can cause major damage, and tramp material can seize the rotors. The correct inlet filters must always be fitted and maintained, although minor scratches and dents can be ground and polished out. Loss in performance due to wear cannot be recovered without fitting new rotors, and possibly a new casing or liner.

Vendors offer various “Service Plans” for servicing (not expensive) and element replacement (expensive) based on hours run and machine condition.

4.2.5.1 Internal Corrosion

Screw compressors are typically made with high quality carbon steel rotors and cast iron housings. Oil flooded machines rely on oil films to prevent corrosion, while dry machines often use PTFE coatings. In-service corrosion tends not to be serious as the heat keeps surfaces dry, and rust particles are worn away immediately.

Compressors which have been out of service for some time, particularly if left open to the weather, can suffer major corrosion damage. Hence standby machines should be regularly be brought into service for a minimum of 24 hours, and machines which are out of service should ideally be sprayed inside with a light coating of lubricating oil, protected from the weather and purged with a small flow of dry air. Note that the compressor must be run to the Service Air manifold, or to atmosphere via a filter, for several hours to remove all the oil, before going back into instrument air service.

Stainless steels are not normally used in screw compressors, primarily because of their significantly greater thermal expansion coefficient and tendency to gall if parts rub. They are also more expensive and more difficult to machine accurately.

4.2.6 SCREW COMPRESSOR – MAIN COMPONENTS

4.2.6.1 Rotor Set

Figure 4,2 – 2 Dry Screw Compressor Element

Instrument air ("dry") screw compressors require 2 screw stages in series to achieve the required pressure. The High Pressure (HP) stage or element will be physically smaller, to suit the increased density. Otherwise the 2 elements are very similar.

A dry screw element comprises a matched pair of helical screw rotors running in mesh. The screw thread profile is special, as it forms a series of air seals between air pockets of increasing pressure. There are several proprietary designs, typical of which is the 4 / 6 design. In this design a 4 lobed "male" rotor with bulbous lobes meshes with a 6 lobed "female" rotor with narrow tapered lobes. The "male" rotor acts as a set of continuous rotary pistons, and the female rotor as matching cylinders. The rotors should not actually touch each other or the casing, rotor timing is by means of timing gears. The "male" rotor is driven by the input shaft and does virtually all the compression work, thus the timing gears carry very little load.

Each rotor runs in two sets of rolling element bearings, one at each end. The bearings are set up and pre-loaded very precisely to maintain shaft position. The timing gears sit outboard of the Non-Drive End bearings. Bearings and timing gears are oil lubricated. Sophisticated labyrinth seals separate the oil from the oil-free air, and minimise the air loss.

As the pair of screws rotate, air is drawn in from a shaped port in one end of the casing, compressed by the meshing screws, and discharged at the other end of the screw set. Since the screws have a fixed throughput volume and a fixed geometry, the capacity and pressure ratio is, in effect, designed in. Some degree of capacity control can be achieved by a combination of suction throttling, internal recycle valve (slide valve) and, more recently, inverter-driven variable speed drive.

Dry screw compressors generate significant temperatures due to the heat of compression, and air leakage friction losses. Hence they must be built with mechanical clearances which permit a substantial back-flow of air. This reduces the capacity of the compressor compared to its displacement, and reduces efficiency.

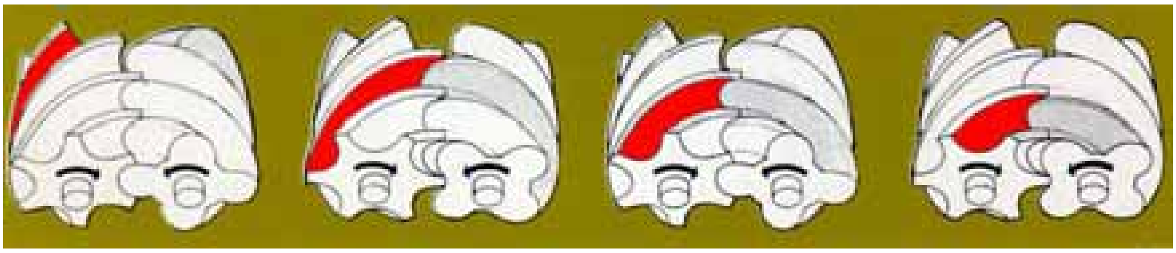


Figure 4,2 – 3 Twin Screw Compression Principle

OIl-flooded screw compressors can have the same basic geometry, but allow oil into the rotor mesh, which now acts as a timing gear. The timing gear is not required, and the seals become much simpler. The exhaust air is saturated with oil (which must be separated later). A radically different compressor design, which achieves exactly the same results, uses a single oil-flooded screw rotor, fitted with slotted "gate" rotors which mesh with the screw and act as seals. The "gate" rotors run at right angles to the main rotor and are made of special non-metallic materials. Oil-flooded compressors run at lower temperatures than dry compressors (the oil acts as a heat sink during compression), the oil also acts to seal up leaks through clearances. Hence these machines are more efficient. They can also produce a higher pressure ratio per stage and can often deliver the required duty with one stage, making them significantly cheaper than dry machines.

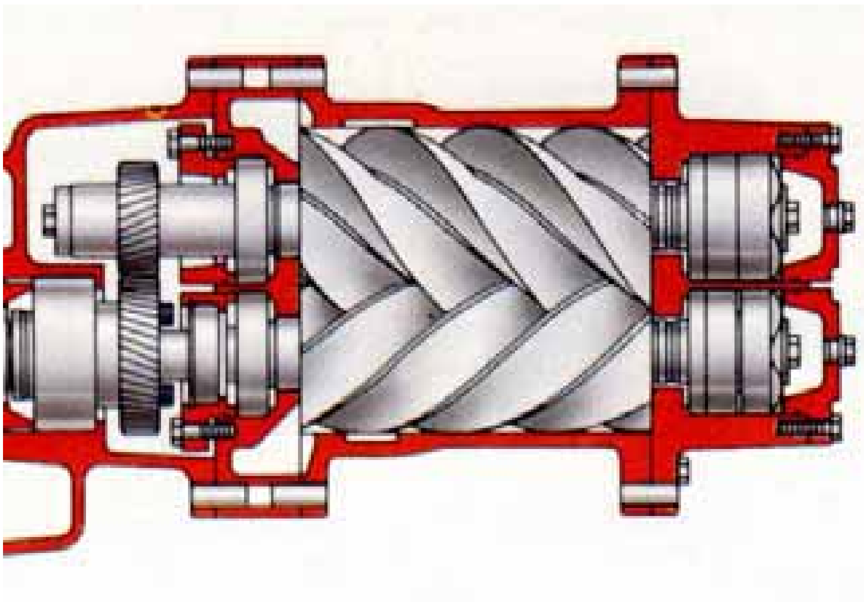


Figure 4,2 – 4 Oil Lubricated Element Design (Simpler than Dry)

4.2.6.2 Element Casing

The element casing consists of one or more matched and machined cast iron housings, enclosing the rotors, housing the bearings and seals, and forming the oil chambers for the bearings. Each casing is a matched and doweled set of parts. On package air machines, the casing is flange mounted to the drive gearbox. The casing has cast-in oil ways and a cast cooling jacket.

4.2.6.3 Gearbox

Package air compressors have an integral speed-increasing gearbox, in the form of a small Bullgear machine. The Bullgear shaft is driven by the electric motor, and the pinion is mounted directly on the end of the driven rotor. Dry compressors normally have two stages thus two driven pinions. The set-up of the gearbox is determined by the element build quality and the spigots & fits of the casings.

Oil-flooded compressors, which may have only one stage, still require the gearbox to drive the compressor element at the appropriate speed.

The gearbox is mounted to the baseframe and forms the structure of the compressor. It may contain or enclose the Intercooler.

4.2.6.4 Intercooler & Aftercooler

Packaged dry screw air compressors normally include an Intercooler and Aftercooler. The Intercooler is integral to the machine as it cools the LP stage discharge air for inlet to the HP stage. If the intercooler were not present or not working, HP discharge temperatures would be excessive and the rotors would rub. The intercooler is normally a proprietary shell and tube design, integrated into the compressor construction. Condensation produced by the intercooler must be drained off by an automatic device, to prevent damage to the HP stage.

The aftercooler is not integral to the operation of the compressor, it may be dispensed with if high temperature (about 150 C) air is required. The main purpose of the aftercooler is to cool the air sufficiently to knock out most of the moisture, prior to entry to an air drier. The aftercooler is typically of shell and tube design, mounted local to the compressor package or inside the housing. The aftercooler and automatic moisture drain must work, or the drier will be overloaded.

Oil-flooded compressors work on a different cooling principle, most of the heat of compression goes into the oil. Hence the large cooling load is the oil cooler. A small aftercooler may be fitted, to reduce outlet air temperatures and permit moisture removal.

4.2.6.5 Seals and Bearings

In a dry screw compressor, the seals are sophisticated labyrinth seals, located between each of the 4 rotor bearings and the compression element. The primary purpose of the seal is to retain lubricating oil in the bearings, and to prevent it from entering the compression air. The secondary purpose is to minimise air leakage to atmosphere. A small amount of air, with traces of oil, is vented from the breather, via a mist filter. Oil is returned to the lubrication system.

The bearings are basically high precision ball bearings, set in groups to achieve rotor support and control pre-load. They are not standard stock bearings, and the set-up requires special tools. Provided that the oil quality is maintained, the bearings fail predictably according to fatigue, this permits elements to be changed out on the basis of time or vibration monitoring. There is always the risk of random bearing failures, good vibration alarms may be able to detect the failure before rotor damage occurs, although the element must be changed.

In oil-flooded machines, the seals are much simpler, their purpose is to control the air flow from the compressor element into the bearing area. There is no direct leakage path to atmosphere.

4.2.6.6 Control Devices

Screw compressors are nominally fixed-ratio and fixed-volume machines. This is set in manufacture and cannot be changed in the field. If the discharge pressure does not match the compressor rating, power is wasted and the compressor also becomes very noisy. Control measures adopted include suction throttling, internal slide valve (internal compression ratio adjustment) and variable speed control. Each manufacturer offers standard and optional control devices, to suit the application. The overall control system is managed by a proprietary PLC controller, running proprietary software. Most vendors are prepared to offer tailored systems but these often then mean non-standard PLC's which give problems to field service engineers.

The suction throttle may be a modulating device, to help match the required load, or simply an on/ off device which works as part of a load/ unload control. The matching part of the load/ unload control is a vent valve that opens the compressor discharge to atmosphere, minimising the motor drive load while permitting instant loading.

Internal slide valves are more usually fitted to oil-flooded compressors, as a more sophisticated load control system. They work by reducing the working length of the screw, thus reducing the internal compression ratio and the absorbed power. They are particularly effective on variable pressure ratio systems e.g. refrigeration compressor duties.

A recent design option, made practical by the availability of robust and cost-effective inverter drives, is variable speed operation. This is mechanically simple, saves power and reduces noise and machine wear. Below a minimum load the compressor must still unload and stop.

4.2.6.7 Silencers

Screw compressors produce very high internal noise levels because of the opening and closing of rotor pockets at the lobe pass frequency. This gives a narrow tone band of the order of 800 Hz. These high frequency tones are very identifiable and annoying, equally they are easily silenced by small inlet and outlet silencers. Noise breakout inside the package enclosure is easily dealt with by foam lined panels, provided that all gaps are closed, and doors are not left open.

4.2.6.8 Water and Oil Separators

Water separators are simple devices located downstream of each inter- and after-cooler unit. They comprise a simple baffle or demister device, a collecting chamber and a drainage device. Traditionally, the drainage device was a float trap as used in steam service, but these are notorious for blocking or jamming. More modern systems tend to use a timed solenoid operated drain, with a liquid sensor to check for correct operation. Oil-free compressors can discharge clean water condensate to open or domestic drains, or to deck. Oil-flooded compressor condensate tends to be an oily emulsion, which must be run to oily water drains for separation.

Oil-flooded compressors have an integral oil separator, this vessel is physically larger than the compressor itself, in order to accommodate the oil separator filter unit. The base of the separator normally acts as the lubricating oil sump. The separator comprises a mechanical separator followed by a fine fibre coalescer filter element. This is designed as a wick to draw oil down to a collector rim which returns the liquid oil to the sump. The air/ oil mixture can generate high static voltages, if not earthed these can produce dangerous sparks. The known risk area is the coalescer filter, this element contains earthing wires or straps which must be in good order. The risk is not present beyond the filter element as there is not enough oil present to either carry the charge or to fuel an explosion. Even so, downstream pipework should be metal and fully earthed, any flexible connections in conducting material fitted with earthing wires.

4.2.6.9 Dryers

Air dryers are frequently installed in conjunction with instrument air compressors. The working principle is normally pressure swing absorption onto silica gel beads, in a pair of pressure vessels. Regeneration is by hot air, or cold dry air. Dryers should be able to achieve a dew point of – 40 to – 60 C (atmospheric), these values are required to prevent liquid water or ice from appearing at solenoid valves, especially on exposed equipment during severe winter conditions. Dryers should always be fitted with a dew-point monitor to confirm that they are actually working properly.

Refrigerated dryers can only work down to a dew point of about + 3 C (pressure) which is not dry enough for instrument air service. It is generally satisfactory for service air.

Dryers can only work effectively if the inlet air has been cooled and has had all liquid water removed. Otherwise this water load will tend to overload the dryer. If a dryer is being used with an oil-flooded compressor, effective coalescer filters are required upstream of the dryer, or oil will coat and destroy the drying media.

4.2.6.10 Control & Management Systems

Control of the compressor will be part of the vendor's proprietary package controls. Typically, the control system will monitor discharge pressure, at the very least the compressor will switch on and off, and load and unload, according to demand. More sophisticated control will attempt to load follow by modulating the compressor capability.

The control system will also monitor oil pressure, temperature, etc., carry out start-up and controlled stopping of the compressor. Many modern systems include action logs and alarm logs, although these often can only be read by the service engineer, not the operator.

Because the control system is proprietary, it will often be very limited in its potential for tailoring or compliance with customer specifications. That leaves the choice between accepting a "standard" system, and insisting on a "special" system with attendant costs and risks.

4.2.7 INTEGRATION ASPECTS

- ***Instrument Air Screw Compressors are near-standard packaged units; oil-free designs are preferred.***
- ***There is little or no scope for mechanical tailoring, any interference with the vendor's design imposes cost and time penalties.***
- ***Compressors are specifically designed for the package unit duty, and are not available as bare-shaft units.***
- ***Relevant condition monitoring can assess the health of the unit and defer expensive and invasive maintenance.***
- ***Protective systems are fitted to prevent machine damage, and, on oil flooded designs, prevent a fire or explosion.***
- ***Cooling can be against air or water.***
- ***See Section 2.7.3 for coverage of a Motor driven Screw Compressor Package***

Since instrument air is a "utility" service, cost-effective packages are available almost on a "ready to run" basis. They do not comply with onerous oil industry or vendor specifications. Dry screw compressors are preferred to ensure oil-free air. Compressors built to industry or vendor specifications would in effect be process gas machines, on a price and delivery to match.

Instrument air screw compressors are designed and built as part of packages, the screw elements are simply not available as bare-shaft units. Although they can be bought as spare parts, they are useless without the mountings, drive and air connections.
Vendors build ranges of compressor capacities and pressure options to suit the market. A limited degree of tailoring can be done but this can severely compromise the practicality of the design. For example, although sets can be "winterised" by adding heating and tracing, the additional fittings and lagging can make internal access very difficult. It is preferable to find the best standard fit to the required duty and environment, then adapt duty and environment to suit.

Modern systems include condition monitoring, either as part of the control system or as a routine part of the maintenance/ service package.

Protective systems are fitted to protect against machine damage through loss of oil pressure, or excessive temperatures. On oil-flooded compressors, high discharge temperature trip is an essential trip and should be subject to mandatory testing. Each screw element should have its own relief valve. Equally, the relief valves must be tested.

Dry screw compressors have cooling jackets around the elements, oil cooler and inter/ after-coolers. It is convenient to use a circulated fluid, normally closed circuit fresh water, as the coolant. Heat can then be exchanged against air or, more compactly, water. Air cooling requires a significant cooling air supply and a significant radiator area as the heat to be lost equates to the compressor motor power.

Oil-flooded screw compressors lose most of their heat directly into the oil, which can then be cooled against air or water.

4.2.8 ANCILLARIES

Lubrication System

The lubrication system of a dry screw compressor is fully self-contained and should not come into significant contact with the compressed air. Hence the oil should stay clean and can be sampled and checked for contamination e.g. from damaged bearings. An oil pump, filter and oil cooler are normally fitted, to supply clean cool oil to the bearings and gears. The oil pump is normally driven by a separate electric motor, to provide a pre-start oil supply. Loss of oil pressure must trip the compressor.

An oil flooded compressor normally does not require a separate oil pump. The oil is driven round the system by the discharge air pressure, which pressurises the oil sump. Pre-start lubrication is provided by small oil reservoirs at bearings and gears. Oil flows are controlled by orifice plates in the supply pipes or drillings. The primary purpose of the oil is to absorb the heat of compression, otherwise the rotors will expand and rub or seize. Loss of lubrication will result in a rapid increase in discharge temperature, since there is no measurable oil pressure as such, the failure trip must be based on discharge temperature. Tests have shown that the trip will be fast enough to precede rotor damage or oil mist ignition.

The lubricating oil will be in intimate contact with the air under compression. The inlet filter should remove the majority of dust or dirt in the intake air, but the remaining very fine dust will be collected in the oil. If the filter fails, the oil may rapidly get very dirty, although offshore the greater concern would be salt getting into the oil and holding moisture. Periodic oil sampling should include checks for dirt and salt content.

For further information on Lubrication Systems see **Section 5.2**

Cooling System

A water-based cooling system is expected to cool the circulating jacket water against sea water. The sea water will be supplied from a utility manifold and returned to open drain. A pump will be required to circulate the jacket water. This pump should be interlocked to the main motor starter.

An air cooling system will require a plentiful supply of clean air from a safe location, this will normally be the same as the air supply for the compressor air intake. A ventilation fan will be included in the compressor package, but additional fan(s) may be required if the air inlet and outlet are restricted by ducts.

SECTION 4.3 SCREW COMPRESSOR – PROCESS GAS

CONTENTS

The target duty is the compression of gas within an oil/ gas processing module. The gas is a hydrocarbon mixture of variable molecular weight, including inert gases such as Nitrogen, and may contain corrosive/ toxic components such as Hydrogen Sulphide. The gas is saturated with condensed liquid and may contain liquid slugs.

4.3.1 INTRODUCTION

- ***Screw compressors are available in two basic designs, "Dry" and "Oil Flooded".***
- ***"Dry" screw compressors may be used for hydrocarbon gas compression, but require sophisticated gas seals.***
- ***They are suitable for moderate pressure / moderate flow duties.***
- ***"Oil Flooded" screw compressors are generally unsuitable for hydrocarbon gas compression, as the oil becomes saturated with the gas.***
- ***There is a special niche for "Oil Flooded" screw compression in closed circuit refrigeration circuits, using non-hydrocarbon fluids.***
- ***Such systems have special sealed lubrication systems and often use special oils.***

Screw compressors are not often used on hydrocarbon gas service.

"Dry" compressors have very narrow internal clearances, and have complex timing gear and seal systems. This makes them relatively expensive, yet poorly suited for low molecular weight gas mixtures. They also are not generally suitable for the variable pressure ratio conditions often found offshore. They are suitable for medium pressure, medium flow duties. Where an appropriate duty exists, they are much more compact than the equivalent reciprocating compressor(s), and easier to control than a centrifugal compressor. Process screw compressors are made to order and are not marketed as proprietary packages. Hence, from a packaging point of view, they should be treated in just the same way as a centrifugal compressor.

Dry screw compressors pose few direct safety hazards. They are noisy and have hot surfaces, but both of these issues are thoroughly dealt with in the packaging process. The main hazard relates to release of the gas being processed.

"Oil Flooded" screw compressors are physically simpler than "dry" machines, having fewer, simpler, shaft seals and no timing gears. They also run at much cooler temperatures as the oil absorbs heat. However, since the oil is intimately mixed with the process gas, at discharge pressure, gas will dissolve in the oil and any trace solids, liquids or fume will be very efficiently scrubbed out. Since the oil is fully recycled, it will be fully saturated with hydrocarbon gas and any scrubbed out materials will accumulate. These effects mean that, in general, "oil flooded" screw compressors are unsuitable for hydrocarbon gas processing.

There is a special niche duty, closed circuit refrigeration, where these compressors have proved to be ideal. Non-hydrocarbon refrigerants e.g. Ammonia, HFC's (HydroFluoroCarbons) are now used, CFC's (ChloroFluoroCarbons) have been phased out and HCFC's (HydroChloroFluoroCarbons) will follow. The lubrication system is specially designed to work with oil saturated in refrigerant, this requires special oils and oil recovery systems. These systems are provided as proprietary packages by specialist manufacturers. Since process refrigeration in the oil/ gas industry, where required, is typically achieved using process gas side-streams, closed circuit refrigeration systems are uncommon and are not discussed further.

4.3.2 BACKGROUND & HISTORY

- ***Screw compressors were originally developed for air compression.***
- ***Process compressor manufacturers developed screw compressors to fit the gap in the market between reciprocating and centrifugal compressors.***
- ***Screw compressors are useful in process industries, where pressures are moderate and flow is steady.***
- ***Special versions were developed by refrigeration compressor manufacturers, who wanted to supply compact, reliable refrigeration systems.***
- ***The major market for screw compressors is by far in air compression.***

Screw compressors became possible due to advances in machining techniques. Initial development was for air compression, where their compact size, relative simplicity, and low maintenance requirements made them popular. With the constant drive for low cost, low weight & simplicity, such machines are unsuitable for process duties, and certainly unsuitable for hydrocarbon gases.

Process compressor manufacturers recognised that the screw compressor fitted a niche for medium flow, medium pressure machines, between reciprocating compressors (complex, wasteful of space) and centrifugal compressors (minimum flow concerns, expensive). Screw compressors became available as tailor-made machines for specific process duties.

It was particularly recognised that refrigeration was an ideal duty for screw compressors. Existing refrigeration compressor manufacturers started offering oil flooded screw compressors instead of reciprocating compressors. These screw compressors require very little maintenance, are compact and easy to install.

The vast majority of screw compressors sold are still air compressors, thus process gas machines remain special, tailor made and quite expensive.

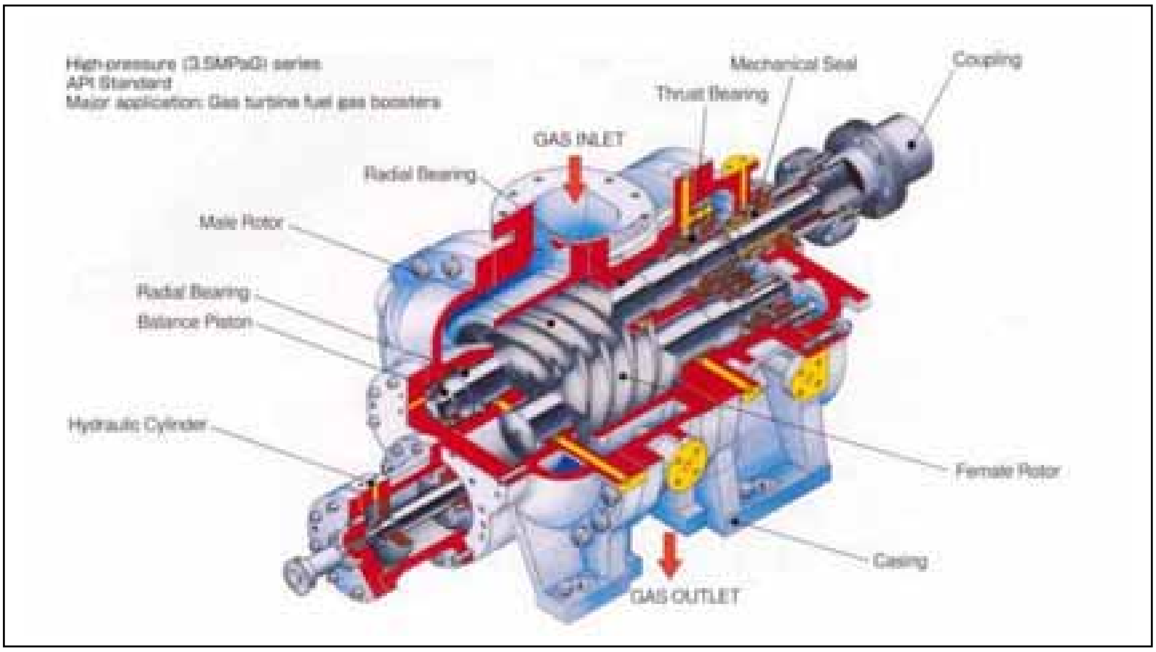


Figure 4,3 – 1 Twin Screw Process Compressor (Cut-away)

4.3.3 HAZARD ASSESSMENT

- ***The hazards associated with a gas compressor have to be considered over its complete operating/ maintenance cycle, not just full steady load operation. Mal-operation / excursions / drive system failures and emergencies must all be covered. The hazards must be seen in context with the installation as a whole, and be compared with alternative compression strategies.***

4.3.3.1 Process Substance Containment Hazards – Hydrocarbon Gases

These hazards are exactly the same as for a centrifugal compressor – See **Section 4.1.3.1.**

4.3.3.2 Equipment Hazards

Operation of Screw compressors on process duty may encounter situations of high suction pressure. The design of these machines has the inherent pressure ratio generated within the machine casing, independent of discharge pressure. The internal pressures generated within the machine can cause major machine damage due to the forces on the rotors caused by the high pressure generated.

(Note the machine imparts a pressure ratio to the compression not a head generation, thus for a typical pressure ratio of 4 within a machine the internal pressure will be 4 bara for an inlet of 1 bara, but 8 bara if the inlet pressure rises to 2 bara.)

Compression of process gas may create limited temperature rise due to a low ratio of specific heats (gamma) – operation of such machines at start up or following purging may required limited suction pressure to avoid overheating on the purge gas (e.g. nitrogen) which can have higher values of gamma.

Other hazards See **Section 4.2.3.2** (Air Service Screw Compressor)

4.3.3.3 Operational / Consequential Hazards

Screw compressors are positive displacement machines, protection from over pressure and temperature are similar to the requirements for a reciprocating compressor – see **Section 4.4.** As a rotating machine other hazards are similar to a centrifugal compressor – see **Section 4.1.3.3.**

4.3.3.4 Maintenance / Access Hazards

Screw compressors are compact machines, the discharge pipework can run at up to 200 C, prior to the aftercooler. Most maintenance risks relate to sprains and injuries related to lifting in confined spaces. There should be no toxic materials present. The lubrication oil is high quality, and poses a small dermatitis risk.

4.3.4 OPERATING REQUIREMENTS

- ***Screw compressors can operate for long periods without major overhaul, but generally require minor servicing at more frequent intervals***

4.3.4.1 Single Compressor Operation – Continuous Duty

If the compressor system has been designed and built to a suitable standard, e.g. API 619, with duplicated filters & oil pumps, then extended single compressor operation is practical.

4.3.4.2 Variable / Intermittent Load Duty

Screw compressors work best at steady loads, they can achieve reduced flow by recycling gas or by speed reduction. The basic pressure ratio (or compression ratio) is built into a screw compressor and cannot generally be changed on-line.

"Oil Flooded" screw compressors have internal slide valves for capacity control, but these designs are not generally suitable for process duties.

4.3.4.3 Emergency Duty

Screw compressors can be started and brought on load quickly, provided that lubricating oil is kept warm, etc., Screw compressors are not tolerant of liquid ingestion, which can be a particular risk on emergency duties.

4.3.5 MAINTENANCE REQUIREMENTS

- ***Screw compressors are serviced in situ. Major overhauls comprise the replacement of compressor stage elements, which may then be refurbished under factory conditions.***
- ***Screw compressor elements are not intended to be rebuilt on site.***

See **Section 4.2.5** (Air Service Screw Compressor).

4.3.5.1 Internal Corrosion

Screw compressors are typically made with high quality carbon steel rotors and cast iron housings. There is little risk of in-service corrosion as oxygen is not generally present.

Compressors which have been out of service for some time, particularly if left open to the weather, can suffer major corrosion damage.

Stainless steels are not normally used in screw compressors, primarily because of their significantly greater thermal expansion coefficient and tendency to gall if parts rub. They are also more expensive and more difficult to machine accurately.

4.3.6 SCREW COMPRESSOR – MAIN COMPONENTS

4.3.6.1 Rotor Set

Process screw compressors may achieve the duty with one screw set, or require two in series. In either case the mechanical design is similar to a "dry" air compressor, the single stage unit being simpler. See **Section 4.2.6.1** for air compressor description.

4.3.6.2 Element Casing

The element casing consists of one or more matched and machined cast iron housings, enclosing the rotors, housing the bearings and seals, and forming the oil chambers for the bearings. Each casing is a matched and doweled set of parts. The casing may be free standing or flange mounted to the drive gearbox. The casing has cast-in oil ways and a cast cooling jacket.

4.3.6.3 Gearbox

A gearbox, typically built by the gearbox manufacturer to the compressor manufacturer's special requirements, is often required.

4.3.6.4 Intercooler & Aftercooler

If required, these will be sourced by the package builder. These should be process quality units built to recognised codes.

4.3.6.5 Seals and Bearings

In a dry screw compressor, the seals are sophisticated gas seals, located between each of the 4 rotor bearings and the compression element. The primary purpose of the seal is to contain the process gas, the secondary purpose to retain lubricating oil in the bearings. There will be a vent or vents to prevent oil contamination by vented gas.

The bearings are basically high precision ball bearings, set in groups to achieve rotor support and control pre-load. They are not standard stock bearings, and the set-up requires special tools. Provided that the oil quality is maintained, the bearings should fail predictably according to fatigue, this permits elements to be changed out on the basis of time or vibration monitoring. There is always the risk of random bearing failures, good vibration alarms may be able to detect the failure before rotor damage occurs, although the element must be changed.

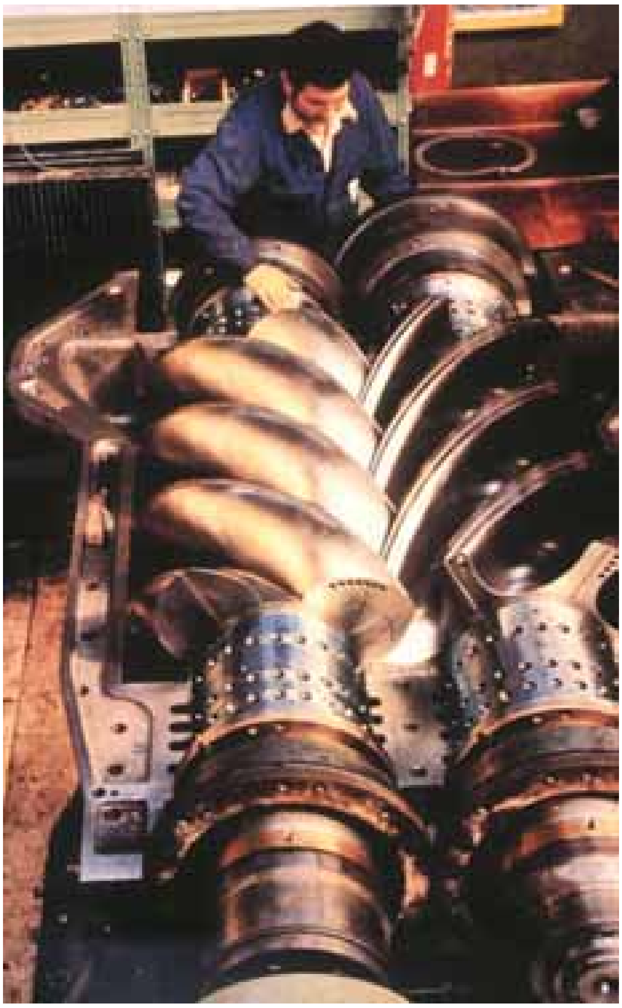


Figure 4,3 – 2 Twin Screw Process Compressor in Workshop

4.3.6.6 Control Devices

Screw compressors are nominally fixed-ratio and fixed-volume machines. This is set in manufacture and cannot be changed in the field. If the discharge pressure does not match the compressor rating, power is wasted and the compressor also becomes very noisy. Control measures adopted include suction throttling, internal slide valve (internal compression ratio adjustment) and variable speed control. Each manufacturer offers standard and optional control devices, to suit the application. The overall control system is managed by a PLC controller, running proprietary software. Most vendors are prepared to offer tailored systems, but these often then mean non-standard PLC's, which give problems to field service engineers.

The suction throttle, if fitted, is a modulating device, to help match the required load. This normally works in conjunction with a recycle valve (and cooler) to achieve the required turn-down.

Internal slide valves are more usually fitted to oil-flooded compressors, as a more sophisticated load control system. They work by reducing the working length of the screw, thus reducing the internal compression ratio and the absorbed power. They are particularly effective on variable pressure ratio systems e.g. refrigeration compressor duties.

A recent design option, made practical by the availability of robust and cost-effective inverter drives, is variable speed operation. This is mechanically simple, saves power and reduces noise and machine wear.

4.3.6.7 Silencers

Screw compressors produce very high internal noise levels because of the opening and closing of rotor pockets at the lobe pass frequency. This gives a narrow tone band of the order of 800 Hz. These high frequency tones are very identifiable and annoying, equally they are easily silenced by small inlet and outlet silencers. Noise breakout inside the package enclosure is easily dealt with by foam lined panels, provided that all gaps are closed, and doors are not left open.

4.3.6.8 Separators

Dry screw compressors are sensitive to liquid ingestion, so it is good practice to install a suitable suction separator as close to the compressor suction as practical.

Inter or after-coolers will often condense liquid out of the condensed gas stream. This liquid should be removed, certainly before the gas enters another compression or heating stage.

Separators are simple devices located downstream of each inter- and after-cooler unit. They comprise a simple baffle or demister device, a collecting chamber and a drainage device.

The collected condensate should be returned to appropriate liquid receivers.

4.3.6.9 Control & Management Systems

The main control requirements will be dictated by the function that the compressor must perform. Flow control, suction pressure or discharge pressure control are common. Control may be done within a dedicated PLC or a plant DCS system. Parameters to be managed may include shaft speed, suction throttle valve control, and recycle valve control.

Lubrication and seal service system controls. These are normally simple mechanical controls to maintain pressure, flow, and temperature of services. Loss of pressure will normally cause a compressor trip.

Process gas isolations are normally achieved using manual valves. This should be by "double block and bleed" principle, slip or spectacle plates should then be used for positive isolation. Automatic isolation and vent to flare on trip is quite possible. The use of power operated valves for process isolation requires additional care to ensure that the valve has actually closed (not just the actuator) and that it cannot open again. This may require disconnecting linkages or air supply pipes. Air operated valves can open or close with tremendous force if air pipes are connected or disconnected inadvertently.

4.3.7 INTEGRATION ASPECTS

Process gas screw compressors are very similar in this respect to centrifugal compressors. See **Section 4.1.7** for relevant comments.

4.3.8 ANCILLARIES

See **Section 4.1.9** for relevant comments.

SECTION 4.4 RECIPROCATING PROCESS COMPRESSOR

CONTENTS

The target duty is the export of produced gas from a small oil / gas field into a common manifold system. The back pressure in the manifold will vary depending on the total gas rate. The gas is a hydrocarbon mixture of variable molecular weight, including inert gases such as Nitrogen, and may contain corrosive/ toxic components such as Hydrogen Sulphide.

4.4.1 INTRODUCTION

- ***Gas Compressors are used to increase the pressure of a process gas, in order to drive it into a pipeline system to an onshore process plant, to use on the producing well as gas lift, to re-inject gas for reservoir pressure maintenance and for use as a fuel gas.***

- ***Reciprocating compressors are used for High Pressure / Low Flow applications, where screw and centrifugal compressors cannot meet the duty.***

- ***This document covers high pressure reciprocating compressors of Horizontal and Vertical types on process duties. Materials of construction must be mechanically capable, and compatible with process fluids anticipated throughout the field lifetime.***

- ***The major hazards relate to the inventory of flammable gas that can be released if there is an equipment failure. Hazard assessment must relate to the complete package and not just the compressor itself. There is an injury risk from a mechanical failure, heavy parts can be ejected at moderate speeds. Compressors have gas seals on moving drive shafts and piston rods. These are safety critical items when handling hazardous materials.***

- ***Reciprocating compressors can, under fault conditions, suffer internal explosions. The design must address prevention / containment / relief of such events.***

Reciprocating gas compressors compress the process gas in a series of discontinuous steps by inducing a fixed volume of gas into a pocket, chamber or cylinder for compression. The size of this pocket or chamber is then reduced mechanically, compressing the gas. At the end of the compression cycle the pocket opens, discharging the high-pressure gas. The compression process causes an increase in the temperature of the process gas. In order to limit the temperature and loads on the compression cylinder, separate stages of compression may be used with intercooling of the gas between compression steps. Often only one or two stages of this compression process are required. In this type of compressor there is never an open gas passage from delivery to suction, though back flow is possible by leakage through the clearances between moving parts.

Figure 4,4 – 1 Reciprocating Process Gas Compressor

Reciprocating compressors can achieve high pressure ratios per stage at low volume flows. They are used for smaller flows than screw and centrifugal compressors, and offer greater flexibility of duty than, in particular, centrifugal compressors. They are mechanically significantly more complicated than centrifugal compressors. Compressor selection is a complex and subjective process, with similar duties resulting in quite dis-similar compressor choices.

The materials of construction must be able to take the mechanical loads; in addition those parts in contact with the process gas must be chemically compatible. Non-metallic materials are often used in seals and valves.

Reciprocating compressors comprise sets of one or more compression cylinders, each with a matching piston. Process compressors are designated as Horizontal or Vertical design according to the orientation of the cylinder centre-lines. Service compressors (typically on instrument air duty) may have different orientations referred to as V, W, L, but these complex options are not used on process units.

Hydrocarbon compressors are typically of horizontal design with opposed pairs of cylinders. This is the most practical way to meet the mechanical balance and gas sealing requirements. Such machines are thus very wide and require significant plot area.

To achieve reasonably practical shaft alignment and permit thermal expansion, flexible couplings are used between co-axial shafts.

Horizontal reciprocating compressors require particularly robust base-frames as the cylinders are supported separately from the crankcase. This is particularly true offshore with the baseplate having to provide the necessary stiffness for alignment and dynamic stability on the offshore installation where the structure itself is too mobile.

Compressors require suitable piping, interstage vessels and coolers with associated control systems. Together with baseplate and driver this forms the "Compressor System".

The vast majority of compressors are shaft driven by a separate electric motor, gas turbine or diesel engine. A drive gearbox may be required to match the compressor and driver speeds. Reciprocating compressors are not normally variable speed as there are a number of ways to modify the output from such machines including :- reducing cylinder efficiency using clearance pockets, control on suction valve opening, and offloading cylinders.

The safety of reciprocating compressors handling hazardous materials is dominated by their piston rod sealing systems. These require appropriate design, maintenance and operator attention.

4.4.2 BACKGROUND & HISTORY

- ***Most early gas compressors were of reciprocating design; more recently even high-pressure applications can be met with high-speed multi stage centrifugal compressors.***
- ***Early compressors leaked gas from piston rod seals, modern compressors have much improved seals with vent systems.***
- ***Early process compressors were often direct driven at low speed by multi-pole electric motors. Modern machines have a faster running speed, driven by a standard motor, possibly with a gearbox.***
- ***Typical modern process reciprocating compressors have shaft speeds in the range 500 - 1000 rev/minute and are tailor made to the required duty.***

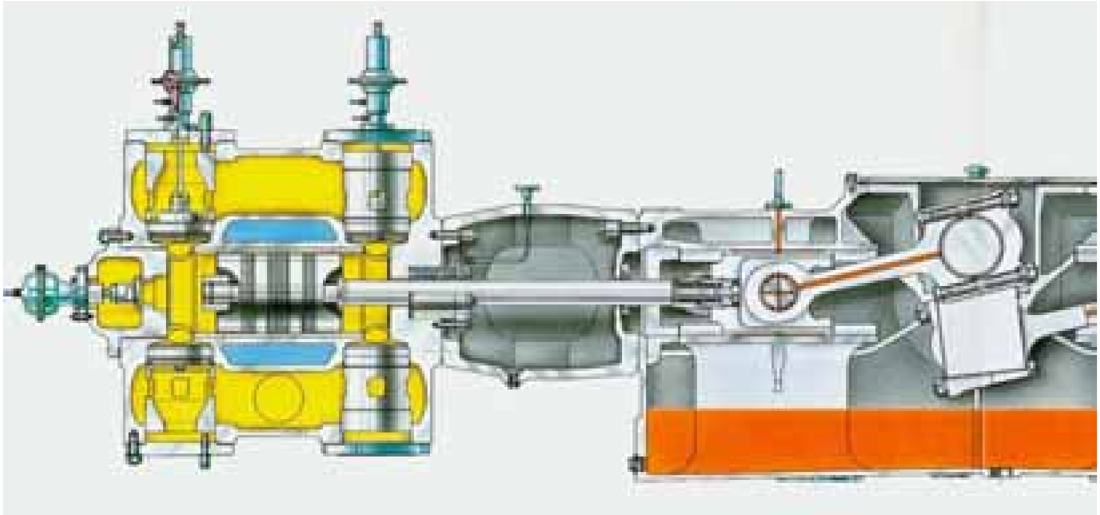


Figure 4,4 – 2 Part Section of Reciprocating Gas Compressor

Gas compressors have been in use for well over a hundred years, early designs were primarily of reciprocating design. The basic design has changed little, but improvements in materials, seals and design principles have significantly improved the service life and reliability. Although centrifugal compressors can now reach the high pressures that previously required reciprocating compressors, low flow and flexible duties often require reciprocating compressors.

Reciprocating compressors consist of a rotating crankshaft, linked to a number of piston rods by connecting rods. Each piston rod passes through a set of packed rod seals, into the compression cylinder. The rod carries the piston, which moves in the cylinder bore in a reciprocating manner. Pistons are normally double acting (compression on out and return strokes) Gas inlet and exhaust is via plate, ring or poppet type valves.

The crankshaft runs inside an enclosed crankcase, in multiple bearings. The crankshaft end of the piston rod is also inside the crankcase, this is supported by a sliding "cross-head bearing". These bearings are oil lubricated, pressure fed by a pump. The crankcase atmosphere is air or, preferably, nitrogen to reduce fire risk.

The trend for design of hydrocarbon compressors has been to a horizontal layout (to accommodate the long piston rod seal systems) with opposed pairs of cylinders (to optimise mechanical balance). Non-hydrocarbon compressors may be of vertical design, which has a much smaller footprint. A special type of vertical compressor is the "labyrinth piston" design, which has non-contacting piston seals.

Improvements in materials of construction and seal design have permitted higher pressure and higher speed operation with reduced emissions. Typically, carbon steel and cast iron components are used for hydrocarbon duties, with non-metallic materials in seals and valves.

Early machines were often direct driven at low speed by multi-pole electric motors. Sometimes the motor was directly mounted on the compressor shaft. These motors were very large, expensive, and not suitable for hazardous areas. Accordingly, modern compressors run faster, driven by standard motors of up to perhaps 8 poles. A drive gearbox is used, where necessary, to match speeds.

Typical shaft speeds are in the range 500 – 1000 rev/min. Compressors may have up to 8 cylinders, in pairs, and are tailor made for the specific duty. Reciprocating compressors have the benefit that the cylinder bore can be changed relatively easily, permitting duty changes.

4.4.3 HAZARD ASSESSMENT

- ***The hazards associated with a gas compressor have to be considered over its complete operating/ maintenance cycle, not just full steady load operations. Mal-operation / excursions / drive system failures and emergencies must all be covered. The hazards must be seen in context with the installation as a whole, and be compared with alternative compression strategies.***

4.4.3.1 Process Substance Containment

On most oil / gas installations the gas being handled will be a mixture of hydrocarbons and some inerts, of relatively low toxicity but posing an asphyxiation risk. Some gases containing hydrogen sulphides may be more toxic. Any release of gas, though diluted below the lower flammable limit, may still pose a direct safety threat. Ideally, such releases should be detected by gas detectors and/ or by smell, and the fault repaired. Some devices such as valve glands, sample points and simple mechanical seals, release small quantities of gas during normal operation.

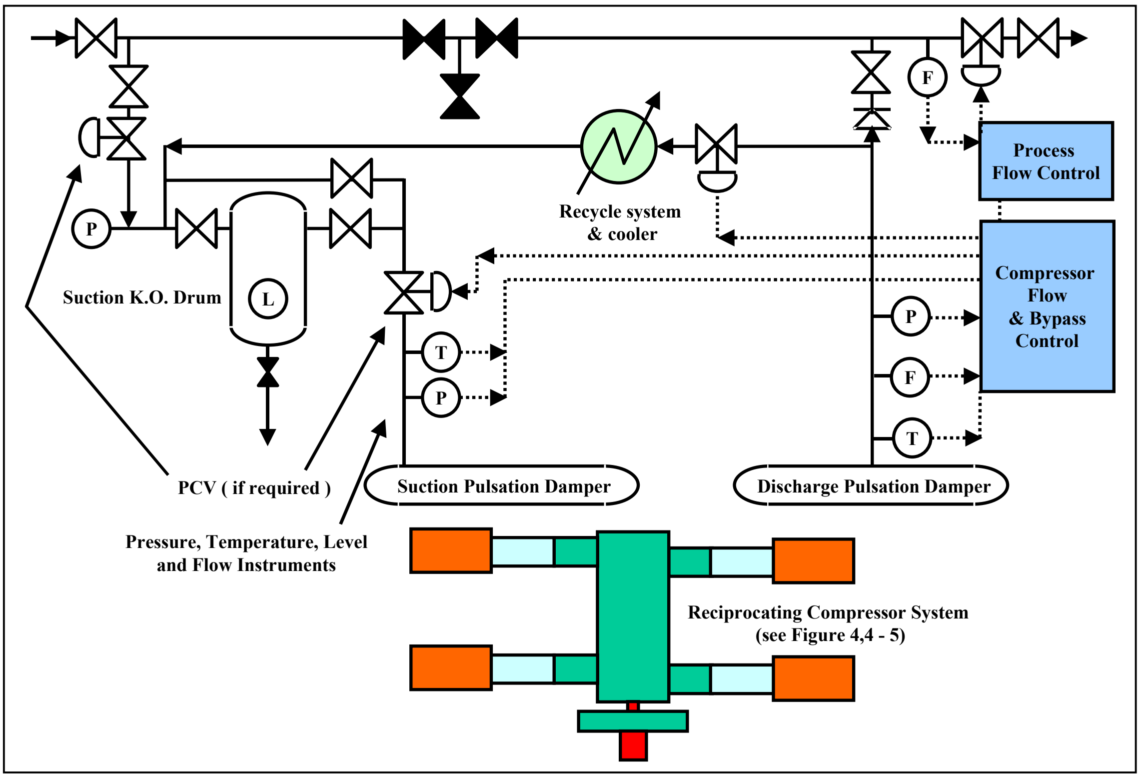


Figure 4,4 – 3 Process Diagram for Reciprocating Gas Compressor

Toxic gases require care because of the immediate risk to people in the vicinity, who can be protected by good ventilation, and where necessary by the use of breathing apparatus. Reciprocating compressors require piped vents to flare or safe area, as the seals continuously release a small flow of gas at low pressure. This gas cannot be recovered as it may contain air.

Hydrocarbon gases pose a real safety threat if released in quantity / concentration sufficient to permit a fire / explosion. Because of the pressures / inventory involved in oil / gas installations, it must be accepted that any leak in the pressure containment envelope is likely to lead to a large release. Designs with the least number of joints and connections are much preferred, and all possible joints should be welded or permanently bonded. Even on small bore lines screw connections should be avoided. Due to the large number of mechanical joints e.g. valve covers, small gas leaks must be anticipated and detection devices installed.

In the event of a major release it may not be possible to get near to the machine to close the isolation valves. Strategically located emergency shut down valves are installed, to prevent venting of large capacity storage or pipe mains. Such isolation valves should permit closure from the control room, but should also close if their energising supply fails or is burnt through. The closure times of the isolation valves should consider both the requirements for effective isolation and the effects of pressure surge. Control valves should not be used as isolation valves because they do not close sufficiently tightly. Closing of the isolation valves should also cause the compressor to stop. A non-return valve in the discharge pipework (as distinct from the compressor discharge valve) will, if it works, prevent the venting of the high pressure gas manifold as part of the release. Operation of isolation valves to safeguard the machine must be designed to avoid introducing their own hazards, machines should be shut down by the action of valve closure, and the design must still allow re-circulation of gas from the compressor discharge to suction or through a pressure relief device.

The process gas pipework within the main isolation valves should be treated as part of the machine system, particularly as part of it may well be supplied with the package. It may have been necessary to install bellows in the main process lines because of space constraints. A bellows failure can cause a major gas release. If the bellows are within the remote isolation valves, then exactly the same emergency isolation action will stop the release. Small bore pipework is weaker than large bore, thus more vulnerable to damage. It is good practice to have robust primary isolation valves, at minimum 1" (25 mm) or 1 1/2" (40 mm) size, at the termination points of small bore harnesses. A failure can then be isolated quickly. Included in all pipework design should be considerations of mechanical resonance, excited by either pressure fluctuations or machine vibrations. Vibrations of pipework and fittings can lead to fatigue stresses being introduced to components, which if not corrected can lead to failure and loss of process gas containment.

It must not be possible to bypass the main remote isolation valves, except as a planned activity, probably as part of commissioning or testing on non-flammable gas. No modification that bypasses the isolation valves should be accepted, without a clear understanding of the necessity of this arrangement, and the associated risks. There is likely to be a venting system, usually to flare, for purging or de-pressurising the compressor system. The system may hold a significant quantity as gas in casings, lines, interstage vessels and coolers. It is possible under some circumstances for gases from one system to be blown into another via common flare or vent lines. This is particularly the case when gas liquids are being handled, these can run down vent lines or cause blockages by freezing water in vent lines.

Compressors inherently increase the superheat in the gas being processed. Hence any free moisture in the gas will evaporate. Any tars or salts will be deposited on internal surfaces, particularly on valves. This will cause fouling. Similarly any solids e.g. dust or catalyst particles will potentially be deposited. These can cause loss of performance by restricting the valves or jamming piston rings, increase leakage by damaging piston rod seals, and in extreme cases cause mechanical damage by limiting piston travel thus overloading bearings.

Reciprocating compressors are in general intolerant of the ingestion of liquid. Slugs of liquid can cause major damage and a major gas release. If there is any risk at all of liquid, the inlet piping

must be designed to avoid liquid ingestion. In all cases, the low points of inlet pipes require manual low point drains, for checks after overhaul / cleaning work. The drain valve should be of straight-through design e.g. plug or ball, permitting a wire or even an optical probe (borescope) to be used for a cleanliness check. The worst design is a long horizontal suction line, with a rising bend to the compressor. Liquid can collect in the line at low flow rates; this is swept up into a wave when flow is increased. A suction knockout pot as close as possible to the compressor, with drains, level detection, alarm and trip, is the normal solution. If liquid is rarely found, the drain valve may be blanked off. While some compressors can tolerate sucking in a mist of clean liquid with no ill effects (in some cases this is used for inter-stage evaporative cooling) accumulation of liquid must be avoided. Operating practices must ensure that all pipework is fully drained of liquid prior to restart the machines, and the machine itself does not contain liquid from process or internal leakage.

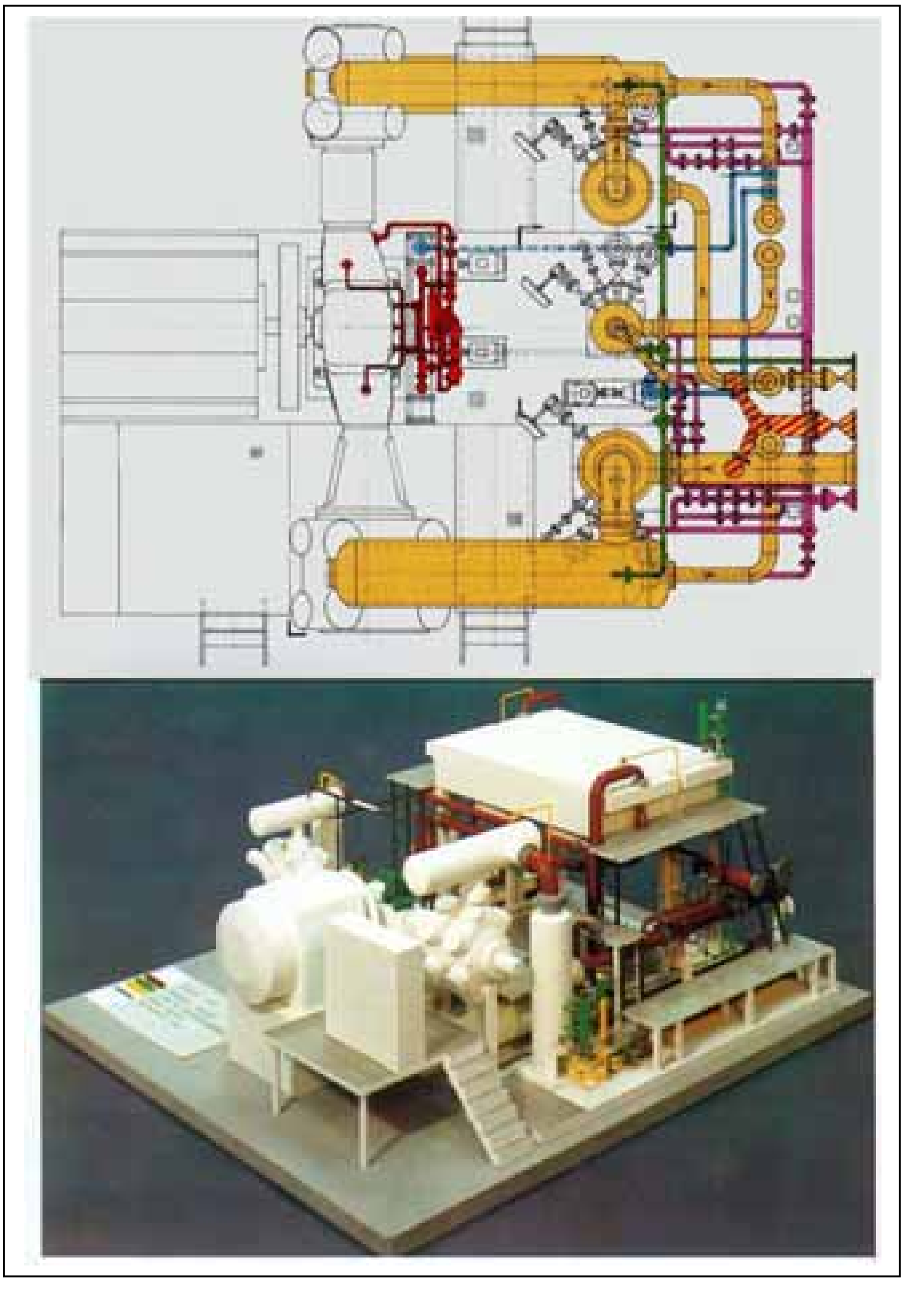


Figure 4,4 – 4 Gas Compressor Schematic and Model

Sealing of process gas within the cylinders is achieved by a series of close fitting packing rings (**Section 4.4.6.5**), leakage from the seal is normally monitored at different positions on the packing box, allowing a progressive view on the rate of deterioration of the seal. Though some leakage can be attributed to bedding in of the packing rings it is unlikely that prolonged or increasing leakage will correct itself and such leakage is in general a sign that seal maintenance is required. The sealing system is highly intolerant to defects and seal wear out can happen rapidly even with a "new" seal. Complex maintenance is required to change and overhaul the seal gland boxes with the highest standards of care required to avoid intolerable defects.

The cooling system can be complex, being required to cool compressor cylinders, sealing glands, gas coolers, and oil coolers. The operational establishment of cooling to a compressor must ensure that all requirements have been met with the appropriate balance of flows to each cooling element. The potential for leakage of cooling water into the machine during normal operations is normally low, however during machine shut downs the risk significantly increases. Any liquid ingress into the machine may result in the machine becoming liquid locked with catastrophic results. Operator activity is required to prove the machine clear prior to any re-establishment, and it is good practice to isolate drain down cooling systems during any extended off line period.

4.4.3.2 Equipment Hazards

The reciprocating action of the motion works imposes a variable torque on the crankshaft, the total effect is that most parts of a reciprocating compressor are subject to fatigue conditions at 1 or 2 cycles per revolution. A failure of the crankshaft, connecting rod or cross-head has the potential to breach the crankcase and eject major parts. This will release a quantity of lubricating oil and may directly breach hydrocarbon containment. Failure or partial failure of the crankcase could displace cylinders leading to very high vibration levels which can rupture hydrocarbon pipework, flanged connections, and foundation bolting.

Within the cylinder, loosening or failure of the piston nut or cross-head nut can cause the piston to be driven against the end of the cylinder, breaking the cylinder end or bending the piston rod. A bent or unsupported piston rod could then wreck the piston rod seals. Failure of a valve cover or valve retainer could cause ejection of a valve complete with cover. Any of these failures open a large diameter hole from the process side to atmosphere, this will cause a major release until remote isolation valves are closed. Stopping the compressor will not stop the leak. Ejected parts may be expelled with a degree of force dependant on the gas energy stored within the machine. A rigorous maintenance and inspection regime is required to mitigate the risks of these hazards.

Figure 4,4 – 5 Four Cylinder Gas Compressor in Workshop Assembly

Reciprocating compressors are particularly vulnerable to damage from liquid slugs, these can instantly cause any of the above failures. As noted earlier it is paramount to prevent ingestion of any liquid, it is particularly important to ensure that all liquid is removed before starting a compressor. Some compressors require cylinder and gland lubrication, in such cases it is important that operation of the lubricating system is inhibited with the machine offline to avoid a build up of oil.

Oil feed pipes to bearings are at relatively low pressures (3 - 5 barg) but can drip or spray oil if damaged. The oil may pose personnel risk (toxicity, spray in eyes, or as a slipping hazard) or catch fire from a hot surface. Compressor metal temperatures are unlikely to be high enough, except as a result of ongoing bearing failure. A failed or failing crankshaft bearing can generate sufficient heat to ignite oil. The benefit of a nitrogen atmosphere in the crankcase is that such fires should be prevented. Opening a crankcase cover can let air contact hot, oily, metal, provoking a fire or explosion, procedures should allow cooling of the machine so that by the time the equipment has been isolated and covers removed the hazard is no longer present. Sets should not be run with crankcase covers loose or partly bolted, as this could let air in.

Mechanical shaft couplings pose a significant safety risk, particularly if neglected, or if the compressor is subject to serious misalignment or vibration. The potential for damage (and the amount of power wasted) within a coupling increases with the misalignment. Reciprocating compressors run relatively slowly, thus a failed coupling is unlikely to be thrown far. Vulnerable components (e.g. oil flexible pipes, cables, seal lines) ideally should not be located tangential to a major drive coupling. The abrupt loss of load and shaft inertia could provoke a dangerous overspeed event on the driving machine.

The consequence of machine failures can be rapidly amplified by the very high vibration levels possible once the balance of internal forces is lost. This can lead to loosening of all connection and containment bolting. Prompt action is necessary to avoid the escalation of any event.

For details of Bearings, Seals, Shaft Couplings and related hazards see **Section 5** – Ancillary Systems & Equipment.

Overspeed and Reverse Rotation

Where the compressor is driven by a variable speed device, such as a gas turbine, the compressor must be protected from overspeed by the speed control system of the driver. In the event of coupling failure, this control is lost along with the drive. Reciprocating compressors have self-acting valves, and thus cannot be forced to spin backwards by the gas pressure. If both delivery and suction valves are jammed partly or fully open, gas will vent back into the suction line. Significant valve faults are normally detected quickly in operation, as the effectiveness of the compressor is compromised.

A gas compressor can be driven backwards e.g. by incorrect electrical connections to the motor. The compressor will run and will compress gas, but the bearings and lubrication system are not intended for reverse running and will be damaged. The shaft driven oil pump, if fitted, may well not work if run backwards.

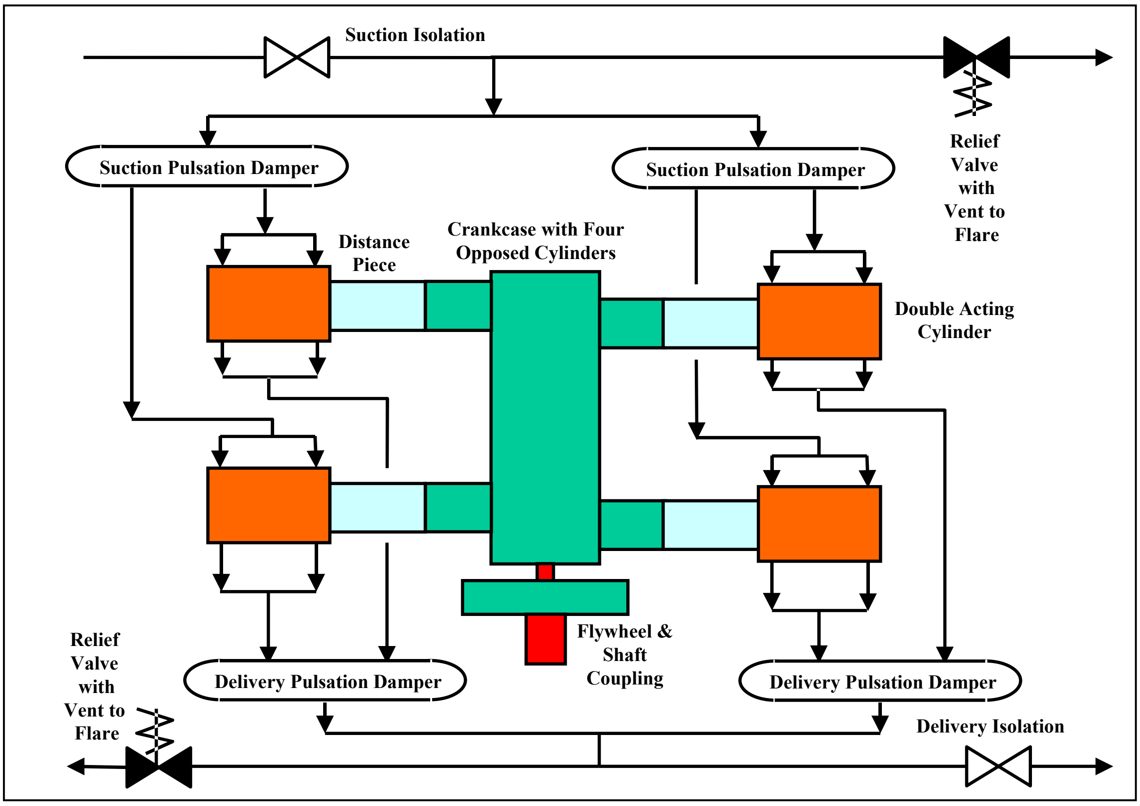


Figure 4,4 – 6 Suction and Delivery Pipework – Reciprocating Compressor

4.4.3.3 Operational / Consequential Hazards

An abrupt loss of the operation of the compressor may cause disruption of the upstream or downstream systems. This may result in systems being shut down, or load being transferred on to other compressors. The safety studies carried out as part of the safety case must ensure that there are no circumstances where a compressor failure might cause an unsafe condition e.g. over-pressurisation of a pipe header.
A compressor can cause problems without actually failing. Examples are: -

- A fault in the load control system can result in rapid changes in flow or pressure; this disrupts upstream or downstream systems.
- A fault in the control system lets a process parameter drift outside the normal operating area. Trips and alarms normally protect against an individual value being unsatisfactory, but it is much more difficult to protect against a combination of changes that make a system inoperable or less efficient. It is up to the operators to remedy the situation.
- A change in the process gas composition, caused by a process upset or change in feedstock, can rapidly change the compressor discharge temperature or pressure. Reciprocating compressors are relatively tolerant to composition changes.
- Failure or partial failure of the machine valves will result in gas recycling within the machine. This can cause high temperatures within the machine, the balance of forces within the machine to be disturbed sufficient to cause bearing overload, interstage pressures to be to

high, thus lifting interstage relief valves, and the potential for larger back-flow through the machine once shutdown.

- A variable speed compressor can run under or over speed, within the mechanically safe range; the relief / vent system must be able to cope with excursions for conditions normally outside the process envelop and with the increased gas flow generated by the compressor running up to trip speed.

- Reciprocating compressors generate significant pulsations in both suction and discharge lines. These pulsations can be greatly reduced by good pipework design and by fitting tuned pulsation dampers. Note that these dampers are not the same as pump pulsation dampers, they are simpler and do not contain moving parts.

- Reduction in the capacity of the machine can be achieved by offloading one or more cylinders. Though this can be designed as a normal operating mode, the faciltiy can be available for use during transient operations (start up / shut down). Such options in the machine operation can cause an imbalance of forces, in this case the configuration may only be suitable for short term activity and extending the activity can lead to machine failure.

If a standby compressor is already connected up and under automatic control, load may be shed to it without operator intervention. This is likely to pose negligible risk. If operators feel obliged to bring a spare machine into service quickly, they may take potentially hazardous shortcuts, for example omitting gas purging. If the status of a machine under overhaul is in doubt, and this machine is brought back into service in a hurry, serious risks are being taken. This was one of the prime causes of the Piper Alpha fire.

Where the installation is subject to significant motion, for example when under tow or during a storm, the motion may exceed the capabilities of the compressor. The unit may have to be shut down as a precautionary measure; otherwise mechanical damage may be caused. The most sensitive system is likely to be the lubrication oil system; movement or roll angles may interfere with oil distribution & return, or cause spurious level trips.

4.4.3.4 Maintenance / Access Hazards

The standards of maintenance for reciprocating compressor must be maintained at the highest level. Reciprocating compressors are vulnerable to incorrect mechanical standards, these can lead to rapid deterioration and failure of components leading to potential for disruption of the machine and loss of containment of the process gas. Examples of this are -:

- Correct assembly and fitting of the self actuating machine valves is crucial to machine operation. Though such valves are normally designed to be unique to a particular position and duty on the machine it may still be possible to confuse the installation. In such cases this can cause the machine to be gas locked with catastrophic results. Machines returning from external maintenance may require preservative actions to be reversed and the removal of dessicant bags from valve ports is also vital.
- Incorrect bearing clearances – on crankshaft this has led to failure of the crankshaft and major machine disruption.
- Incorrect set up for piston rod connections either for cylinder or crosshead can cause complete failure of piston rod.
- Wrong maintenance standards applied to recover wear on piston rods have caused rod failure and loss of containment through the seal.
- Wrong maintenance standards applied to recover wear on crankshafts has resulted in failure of crankshaft, disruption of the crankcase and loss of process gas containment.
- Incorrect installation of the process gas valves can block in the gas pressure causing the cylinder to be over-pressurised, although relief valves should provide protection.

Horizontal reciprocating compressors are wide, low machines, so most parts are readily accessible. Access may be restricted by pipework and fittings, with consequent trip and head injury hazards. Valves and seal assemblies may require handling or lifting devices to reduce the risk of hand injuries and muscle strains. Vertical compressors can easily exceed 4 m high, requiring platforms or scaffolding for access. The valves, which require the most frequent attention, are mounted high on the machine.

Seal housings and crankcases may have nitrogen purges, these purges must be isolated and enclosed areas ventilated and checked for safe access – even if for head access only.

These compressors are maintained in situ, requiring effective lifting facilities and laydown areas.

Compressor control panel and ancillaries may be located on the same skid, or adjacent, or in a control room.

4.4.4 OPERATING REQUIREMENTS

- ***Reciprocating compressors are generally designed for long periods of steady operation, up to perhaps 3 years service without major overhaul. Valves and seals require service at perhaps 6 or 12 monthly intervals.***

4.4.4.1 Continuous Duty

Selecting equipment for continuous operation, requires steady, efficient and reliable operation. Reciprocating compressors cannot run continuously for more than a maximum of about 12 months before valve and seal wear becomes unacceptable, and the motion work may only be able to run for up to 3 years between major overhauls. Sophisticated monitoring will give the best information to permit maintenance intervention to be well-planned and of the shortest possible duration. Chemical additives may be used to control fouling. Materials are selected for negligible corrosion in service.

4.4.4.2 Variable / Intermittent Load Duty

Reciprocating compressors are tolerant of duty changes, but, being positive displacement machines, recycle control is normally used to manage flow changes. Some machines are fitted with unloading systems, these can be complex and may cause local high temperatures. Reciprocating compressors can be started up very quickly, provided that detailed checks are carried out and, above all, no liquid is present in the compressor or suction system.

4.4.4.3 Emergency Duty

Reciprocating compressors are not ideal for emergency duty as they require operator checks and attention during starts. It is practical to have a set running on full recycle at low power and perhaps reduced speed, ready to pick up load in a few seconds. Again, the potential presence of liquid in the suction line would pose a major hazard.

4.4.5 MAINTENANCE REQUIREMENTS

- ***Reciprocating compressors are designed to be maintained in situ. Seals and valves can be removed and replaced as assemblies. Major parts e.g. cylinders, crankshaft, require heavy lifting facilities. Control and isolation valves may be very large, hence also requiring heavy lifting gear.***

Maintenance requirements for reciprocating compressors are a combination of preventative maintenance of the motion work and major components and essential predictive maintenance based on measured performance such as valve temperatures, rod drop, vibration.

Valves, gas seals, bearings can be accessed by removal of local covers. Removal / maintenance of seals and bearings requires lifting equipment to support and position motion work as required. The pistons and rod are normally removed as an assembly by unscrewing the cross-head nut. Only then can the gas seal, and the piston rings, be inspected and changed. Reciprocating compressors are thus relatively maintenance-intensive, reducing the availability compared to centrifugal units.

The alignment and levelling of cylinders to crankcase should be checked periodically, particularly after any cylinders have been disturbed. Any misalignment or movement will result in increased fatigue loads on cylinder supports and fasteners. Movement is often shown up by "panting" of the oil film in mechanical joints.

Special fasteners permit the tension or stretch of fasteners to be checked in service. Hydraulically tensioned fasteners are often fitted to ensure accurate tightening in confined spaces.

The motion works bearings will be white metal, possibly of shell construction that would simplify maintenance. A high level of fitting skill is required to work on these machines.

The piston rod and gland arrangements are precisely engineered to avoid gas leakage, assembly and installation of these components requires some of the highest levels of quality engineering and attention to detail to provide reliable operation.

The control and remote isolation valves will be large and very heavy, often posing a difficult lifting problem. It is important that the full operation of these valves be tested before the plant is returned to service. It may be necessary to carry out in-service operating tests on valves to ensure their reliability.

4.4.5.1 Internal Corrosion

Reciprocating compressors are relatively thermodynamically efficient, not heating the process gas as much as centrifugal compressors. They also often have inter-coolers and water cooled cylinder jackets. Hence liquid may well be condensed inside the compressor. Some process compressors are of a "lubricated" design, where a process-compatible lubricating oil is injected in small quantities into the cylinder. This oil lubricates the piston rings and gas seals. The oil provides a significant degree of corrosion protection. The main corrosion potential is if the lubricating oil supply stops, while condensation continues. This might occur when a set was stopped, but not isolated and purged with dry gas. Light hydrocarbon condensate will wash off the oil film, leaving surfaces exposed to trace corrosive elements in the gas.

The worst corrosion occurs if process deposits (salts, oxides) are exposed to damp air under poor ventilation conditions. This may occur if there is a failure that prevents a normal process clean out. The system is then opened for inspection, and left open while parts / resources are obtained. This can be avoided by proper cleaning / venting activities after the inspection, and even by applying corrosion inhibitors.

The crankcase and cross-head areas should be completely separate from the process, with clean lubricating oil in a dry gas (ideally Nitrogen) atmosphere. There should be no potential for corrosion here, although it is very wise to periodically test the oil for water, chlorides and light hydrocarbons.

4.4.6 HORIZONTAL RECIPROCATING GAS COMPRESSOR MAIN COMPONENTS

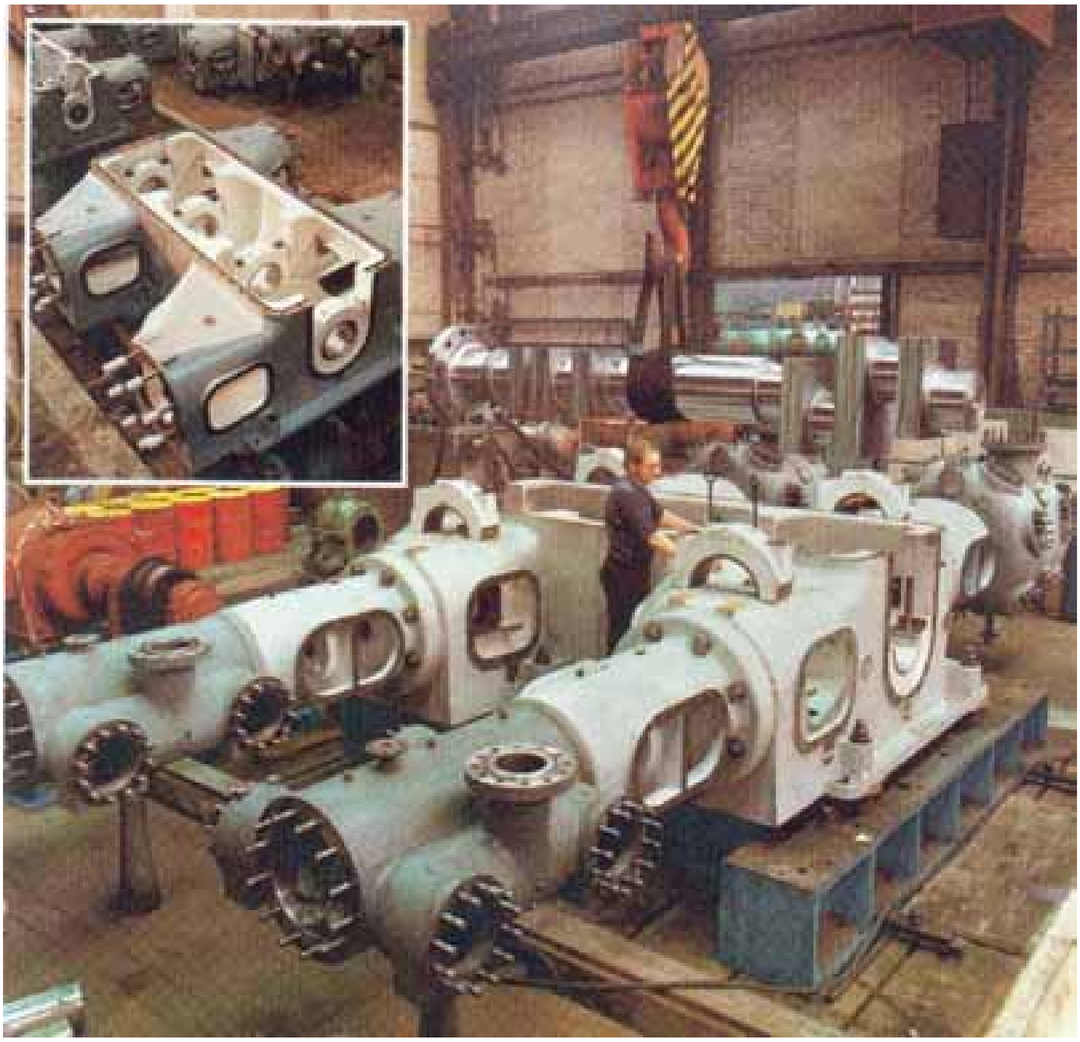


Figure 4,4 – 7 Static Parts Assembly with Crankcase Shown Inset. Crankshaft on Crane

4.4.6.1 Crankcase or Frame

The crankcase or frame is a cast or fabricated box, fully enclosed, containing the crankshaft and connecting rods. It provides a mechanical location and support for the inboard end of the cylinders. It needs to be gas and oil-tight, as it forms the "wet" or "dry" sump for the oil system.

The crankcase must be very stiff, as it carries all of the motion work loadings. For horizontal compressors, the crankcase access will normally by via bolted top covers, internal access will be restricted by stiffening webs and bars. The main crankshaft bearings (normally 2 per cylinder pair) are set into the crankcase.

Vertical compressors have a very tall crankcase with side access covers. The bottom of the crankcase is removed to access the crankshaft.

4.4.6.2 Crankshaft and Connecting Rods

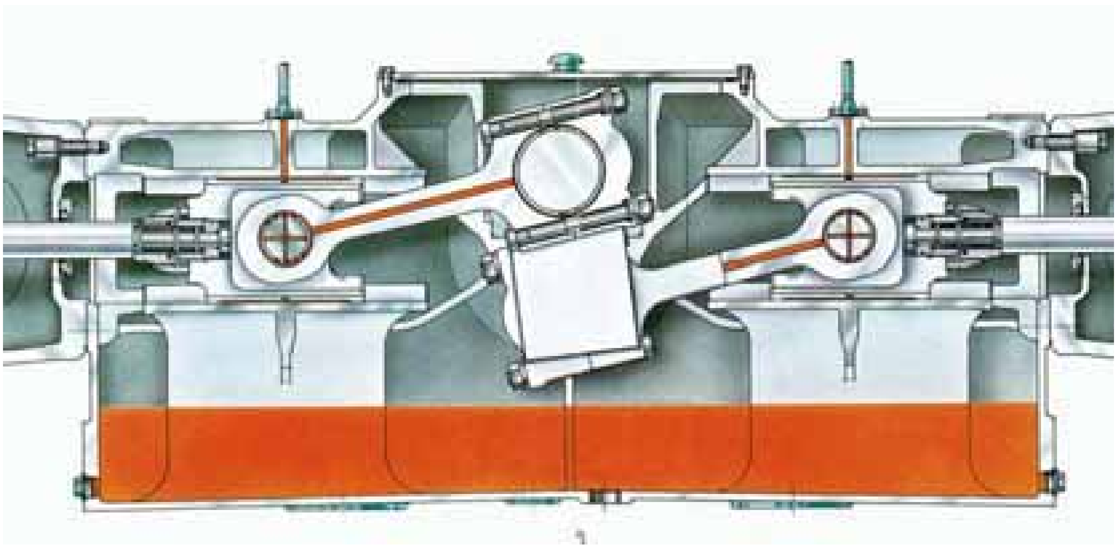


Figure 4,4 – 8 Crankshaft Throws, Connecting Rods, Crossheads on Typical Opposed Cylinder Machine

The crankshaft is a one-piece forged and machined steel component of significant weight and precision engineered to exact dimensions. It has wide journals to match the main bearings, and narrower ones to carry the “big end” bearings. A typical 4 cylinder horizontally opposed process gas compressor has a crankshaft with 4 “throws”, each to drive one piston. The “throws” are in pairs, each pair very close together but 180 degrees opposed. The two pairs, wide apart, will then be offset by 90 degrees. This permits each pair of “throws” to push opposing pistons out together and in together. This makes each pair of pistons, as near as possible, dynamically balanced. By setting the pairs of “throws” at 90 degrees, this produces 4 torque pulsations at 90 degree intervals, rather than 2 double size pulsations at 180 degrees. Even so, the torque pulsations are very significant and must be allowed for in the drive design.

Vertical compressors, and horizontal compressors other than the "opposed pair" design, cannot be fully dynamically balanced, large out of balance forces must be carried into the foundations. These designs are less likely to be selected for large offshore applications.

The crankshaft has a forged flange on one end to carry the flywheel and drive coupling. Belt drive to the flywheel periphery may be used in smaller machines, this is not preferred for damp conditions.

The connecting rods are short, dumbbell shaped forged steel bars, linking the crankshaft “throw” to the crosshead. The connecting rod has a “big end” bearing at one end, which fits around the

crankshaft “big end” journal, and a “little end” bearing at the other end, which drives the crosshead.

Passages are drilled in the crankshaft and connecting rods to provide continuous pressure fed lubricating oil to all the bearings.

4.4.6.3 Crosshead

Contrary to the design of automobile engines, and some designs of refrigeration compressor, the connecting rod is not fitted directly to the piston, but to the end of a piston rod. This is to enable sliding seals to be fitted to the piston rod, to control gas leakage. The crosshead is the sliding block on the end of the piston rod, which links the piston rod and the “little end” bearing on the connecting rod. The crosshead supports the end of the piston rod, carrying the weight of the rod, and, more importantly, carrying the side loads imposed by the crank mechanism. The crosshead carries a flat white metal bearing, this runs on a bearing track set into an extension piece on the side of the crankcase. The crosshead bearing must be set up correctly if the piston rod and gas packing are to achieve reasonable running lives. Access is normally via bolted covers, restricted by surrounding pipework and often by the short distance to an adjacent crosshead.

4.4.6.4 Cylinder, Piston and Piston Rod

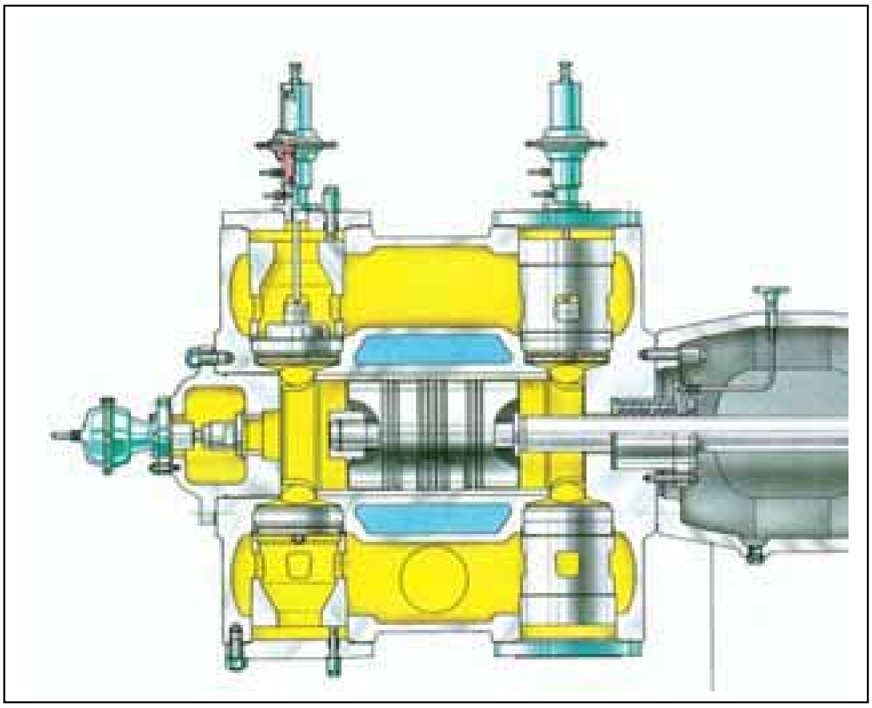


Figure 4,4 – 9 Normal Cylinder and Piston Assembly with Valves.

The cylinder is a forged, or cast, and internally machined tube, which carries the piston and valves. It is mounted to the end of the crankcase extension via, typically, a cylindrical distance piece. This distance piece provides room to accommodate and access the seals on the piston rod. The reciprocating loads generated by the piston compressing the gas are transmitted axially through the cylinder and distance piece to the crankcase, hence these components are subject to fatigue conditions. The inner end of the cylinder is fitted with a gas seal for the piston rod, this seal is normally of cartridge format as the working space is very difficult. The outer end of the cylinder is fitted with a bolted cap, to permit the piston to be removed and re-fitted. The cylinder is often fitted with a removable liner, of wear-resistant or coated material. It is then

possible to re-line a cylinder, rather than manufacture a new one. The space between the liner and the cylinder wall is often used as a water cooling jacket. This poses a known risk of leakage of gas into cooling water and vice versa. Cylinders which have been subject to freezing from frost or process upset should be checked for liner leakage.

The cylinder (or liner) bore is very accurately machined round and straight, it is then honed to a specified finish. Smoothness and lack of ridges or scores is more important than actual dimension. The surface is not polished, as a certain controlled roughness helps to retain the lubricating oil film.

The piston is usually of hollow cast construction, but designs vary. In all cases the piston is smaller in bore than the cylinder, and should not make contact. The piston is then fitted with a series of specially shaped rings, called piston rings. These are normally of split construction and are designed to spring open to suit the cylinder bore. In this way the piston rings ride on the oil film while coping with their own thermal expansion, and that of the cylinder and piston. Note that the cylinder and piston may be at very different temperatures, particularly in the minutes after start-up. Some piston rings are shaped to resist gas leakage, and are called pressure rings. Other rings, normally in the middle of the piston, are shaped to create an oil wedge, and are called bearer bands. Rings may be fitted by pulling them open and sliding them over a solid piston, or by having a built-up piston, which dismantles. The piston is fitted to a step on the end of the piston, and retained by the piston nut. This is a very critical fastening, a number of proprietary designs are used. These usually require special tools and techniques. Use of made up tools or the wrong technique gives a real risk of the piston coming off, and a gas release or personnel injury.

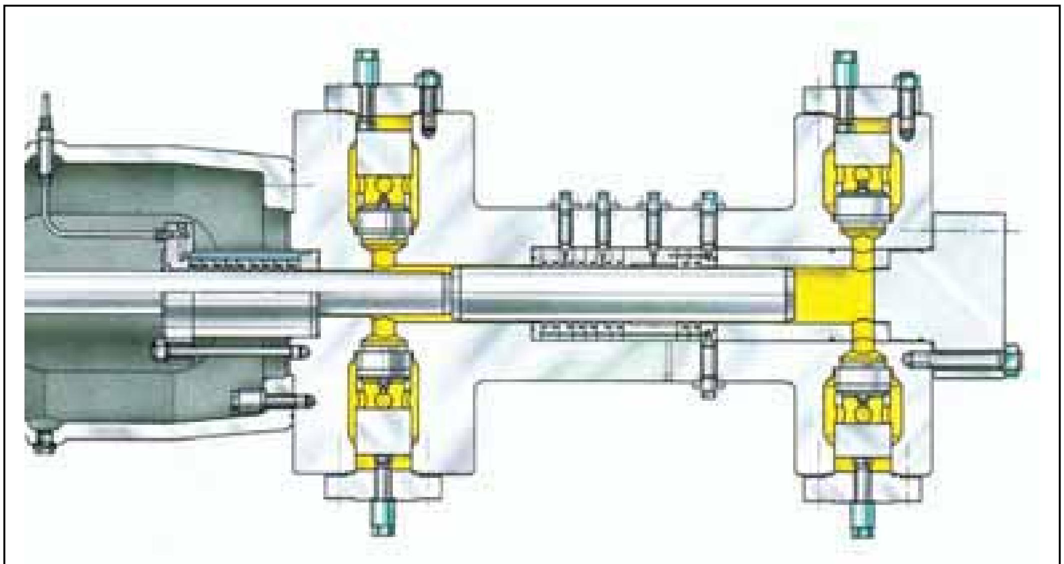


Figure 4,4 – 10 High Pressure Cylinder Arrangement (Plunger Piston)

The piston rod is a long, hard, tough, straight steel rod, often with special coatings. It has been machined, ground and honed, and has special screw thread fasteners at both ends. It is a heavy, awkward, expensive and easily damaged component used on a task which is generally intolerant of any damage or incorrect dimension. It should be handled as if made of glass, indeed some of the coatings are very nearly glass. The piston rod is screwed at one end to the piston, at the other to the cross-head. It is designed to carry the compression forces, for a large diameter, low pressure piston the piston rod will look too small, for a small diameter, high pressure piston the piston rod will look disproportionately large.
Some high pressure compressors have a double-ended piston rod and two sets of gas seals. This design balances the inward and outward compression strokes, making the two strokes

compress equal amounts of gas and reducing the piston rod load. This design is not preferred as it results in a very long piston rod and two sets of gas seals. It is very difficult to align such a piston / cylinder system correctly.

Certain designs of vertical compressor have a special arrangement where the piston and piston rod have non-contacting labyrinth seals. This "labyrinth piston" design is used where neither oil injection nor PTFE seal rings are desirable. It has the potential for long service life on hot dry gases. It does result in a very tall compressor design.

4.4.6.5 Gas Seals or Rod Packing

Gas Seals or Rod Packing. This is the system of seals on each piston rod. There are normally 2 seals, each with its own function.

The first seal or “Gas Packing” serves to minimise the leakage of process gas along the moving piston rod as it passes out of the cylinder. The normal arrangement is a sequential set of pressure-activated split rider-type seals, each of which settles itself to produce a very close fit to the rod and thus forms a close labyrinth seal. Each seal consists of flat sections lapped to each other with a required accuracy down to a few wavelengths of light, these slide to create a near-gas-tight package. There will always be some leakage across such seals. The seals are typically made of bronze alloys, for relative softness, toughness and thermal conductivity. Other materials are PTFE, carbon, iron, cast iron. Sintered or cast materials are often chosen for machineability and lubricant retention. The seals are stacked in nested disc-shaped carriers, bolted together to from a top hat shaped assembly. Normally, dry nitrogen gas under pressure is blown in part way along the stack, with a process gas / nitrogen mix being vented to flare. If the seal is working correctly, what emerges from the crosshead end of the seal is nitrogen gas only, at low pressure and flow. There will also be a drain for cylinder lubricating oil / condensate wiped off the rod.

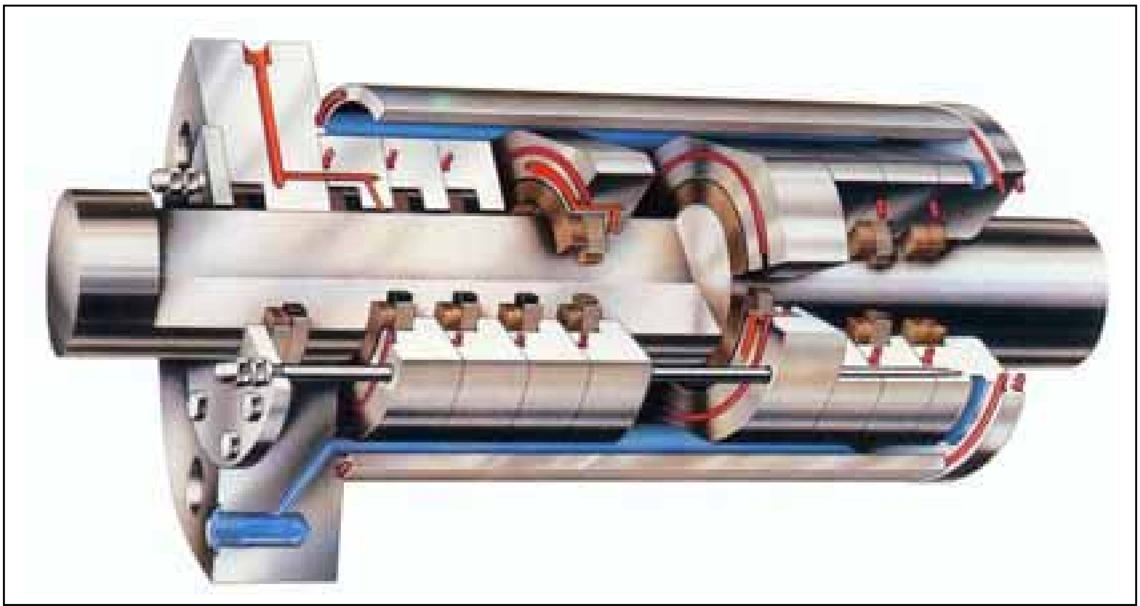


Figure 4,4 – 11 Piston Rod Gas Packing Cut-Away.

Physically, the first seal is located inside the distance piece, which is a cylinder with access covers. The seal is normally pre-assembled on a mandrel, which is a dummy piece of piston rod. The mandrel is loaded into position and screwed onto the end of the piston rod. The seal can then be eased into position in the cylinder end and the piston rod should slide through, replacing the mandrel. The mandrel can then be unscrewed, the seal aligned, tightened up and

tested. Earlier compressors had non-cartridge seals but working conditions inside the spacer are so bad that it was common for 6 hours' work to be spoiled by a single displaced seal ring. Cartridge designs, which can be built up and even static tested in workshop conditions, are far superior.

If the gas is toxic, particularly soluble in lubricating oil, or known to be difficult to seal, a backup gas seal may be installed, in a partition in the distance piece. This arrangement, known as a double distance piece, prevents any gas leaking from the first seal from contacting lubricating oil. Thus the crankcase remains uncontaminated.

The second type of seal is the oil wiper seal, this serves to retain crankcase lubricating oil. The intent is that no part of the piston rod sees both crankcase oil and cylinder oil. The primary purpose of the oil wiper seal is to scrape off crankcase oil and return it to the sump. A secondary purpose is to act as a backup gas seal. In the event that that main gas seal fails, process gas will enter the first spacer. This space will be vented, but will still reach some pressure. To minimise the amount of process gas entering the crankcase and contaminating the oil or possibly causing an explosion, the oil wiper seal also contains gas seal ring(s). The oil wiper seal is fitted in the same way as the gas seal.

The oil wiper seal is fitted in the bulkhead between the distance piece and the crankcase extension, which contains the crosshead and crosshead bearing.

4.4.6.6 Valves

Reciprocating compressors require suction and delivery valves at each working end of each cylinder. Machines often have multiple valves. Each valve is a set of discs held together, normally, by a through-bolt. The valves are self-actuated (opened by differential pressure, closed by a combination of differential pressure and spring force) with multiple gas passages closed by lightweight valve elements for rapid operation. The moving valve elements may take the form, typically, of slotted discs, shaped rings, or poppets. Springs may be slotted discs, or coil springs.

Valves fit into shaped seats in the cylinder end, with a very close clearance to the moving piston. Suction and delivery valves are different shapes, they must be designed not to fit into the wrong seat (e.g. by being different diameters) as mechanical impact with the piston can eject the valve. Similarly, the valve retaining nut is designed to be outside the cylinder, a failed nut can jam the piston and cause major damage.
In some modern machines a common valve is used for both suction and delivery duty, though in theory they fulfil the requirement to avoid incorrect fitting extreme care is needed to understand the required installation and position of such valves.

Each valve is retained in place by a ported cylindrical retainer or "lantern", this in turn is held in by a bolted cover. The bolted cover has to contain the relevant gas pressure and carry mechanical loads from the valve.

Valves can fail closed (by coking up or collecting sticky deposits) or, more usually, fully or partly open (by breakage of valve elements of jamming in of debris). Failed valves immediately affect the process operation, and typically cause increased gas temperatures, but do not pose a direct safety risk.

The more significant safety risk relates to the failure of the valve retainer and cover, failure of the cover opens a large diameter hole to atmosphere, there is a significant possibility of also ejecting the valve and retainer. Although the cover is a robust component, it and its fasteners should be subject to rigorous inspection and fitting practice. Fasteners should only have rolled threads, be bought from approved sources, and should never have threads re-cut. Tapped holes must be inspected for wear and checked with thread gauges if there is any doubt.

The cylinder and valve layout should, if at all possible, promote liquid drainage and prevent the transport of liquid slugs into the compressor.

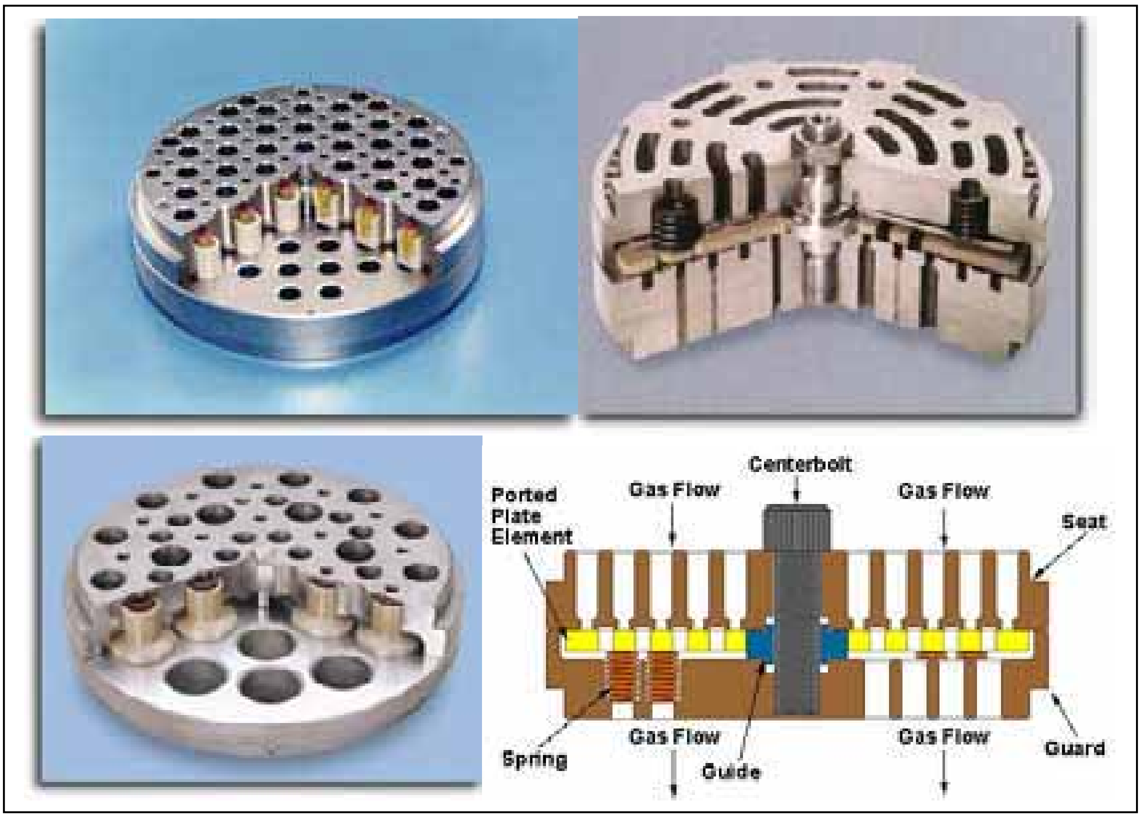


Figure 4,4 – 12 Modern Valve Design Options.

4.4.6.7 Pulsation Dampers

The suction and delivery lines are subject to gas pulsations as valves open and close. The most effective way to minimise these pulsations is to fit expansion vessels as close as possible to the compressor valves. On multi-cylinder compressors, the pulsation dampers may take the form of transverse vessels acting as suction and delivery manifolds. Pulsation dampers do not contain moving parts or elastomer bags, but they often contain baffles or restrictor orifice discs.

On clean duties the pulsation dampers should not require attention, but an increase in pulsation levels may be the result of baffle failure or the build up of chemical deposits. In lubricated air compressors, the discharge pulsation damper(s) are a prime place for coke to build up. This coke is a potential spontaneous ignition point, annual inspections should check for and remove any coke.

Poor pipework design, fabrication, or supporting can result in fatigue cracking on pipework and support welds. This is also true for pulsation dampers, which are relatively heavy and can act as tuned masses, particularly with variable speed machines.

4.4.6.8 Flywheel

A flywheel is normally required to even out the torsional fluctuations imposed by the reciprocating pistons. The more cylinders on the compressor, the less significant this is. The flywheel is a massive cast or fabricated disc attached to the crankshaft end flange. The flywheel mass is concentrated in the rim where it gives the most benefit. Torsional fluctuations can significantly affect the driving machine, and the electrical distribution network on electric motor

drives. The combination of a flywheel and a torsionally soft shaft coupling, is chosen to reduce the fluctations to an acceptable level.

The massive weight of the flywheel requires appropriate design of the crankshaft bearings, and dynamic balancing of the crankshaft and flywheel. This balancing is distinct from the balancing of the motion works, which is a static process.

The bolted connection of the flywheel to the crankshaft is critical, poor fitting or damaged fasteners can cause the flywheel to move relative to the crankshaft, causing mechanical deterioration.

4.4.6.9 Support Systems

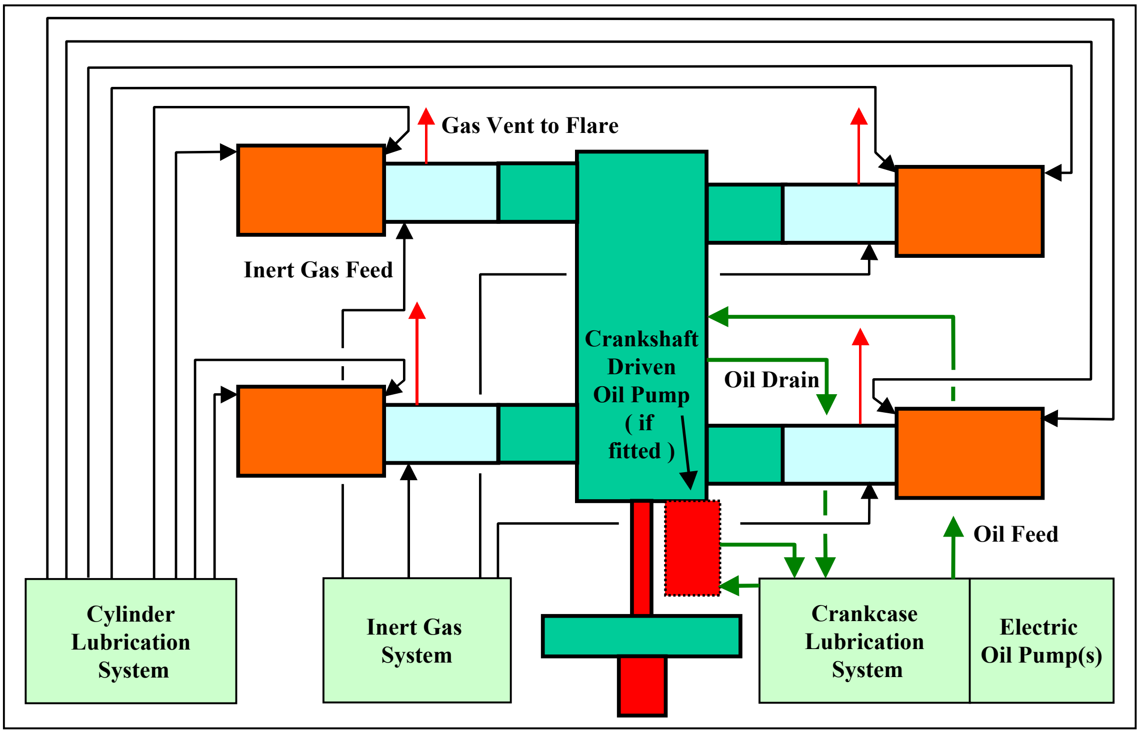


Figure 4,4 – 13 Lubrication and Purge Gas Diagram

Baseframe

This will normally be common with the base frame under the driver (and gearbox if fitted). Rigidity is vital to maintain alignment during temperature and load changes. The baseframe may well have a deep slot to accommodate the flywheel.

Lubrication System

Crankcase lubrication oil may be supplied from the driver (if a gas turbine), but the opposite arrangement is more likely. The system will be mounted on or adjacent to the compressor baseplate, and designed to cope with start up, normal operation and run-down requirements.

Some reciprocating process gas compressors have lubricated cylinders. This lubrication system is completely separate from the crankcase system, and continuously injects very small

quantities of oil into each cylinder, to lubricate the piston and piston rod. The oil is not re-used and mostly goes out with the process gas. Drainage oil, if any, is disposed of and not re-used.

For non-hydrocarbon duties, lubricating oil may not be acceptable, for example because it will poison a reaction catalyst or contaminate a final product. Non-lubricated or "dry" compressors do not put oil into the cylinders, instead they use self-lubricating piston rings and rod packings. Typically, PTFE and PTFE-loaded materials are used. These materials wear significantly in service and generally have shorter lives than in lubricated machines.

"Dry" compressor lubrication relies on the transfer of solid particles from the plastic component to the opposing metal or coated surface. The presence of liquids, particularly oil or water, can disrupt this process and lead to rapid wear of the plastic component. Hence the requirement for design, operation and maintenance practices to keep surfaces clean and dry. Here the "labyrinth piston" vertical design comes into its own, as plastic wear surfaces are not required.

Seal Gas System

The rod packings require a bleed of dry inert gas to keep the distance piece atmosphere free of hydrocarbon if possible, and certainly non-flammable.

Suction Knock-out Pots

Depending on the gas being handled, liquid water or light hydrocarbons may condense out. Liquid droplets, or slugs in particular, can seriously damage reciprocating compressors. It is good practice to install an appropriately designed knockout pot immediately prior to the suction manifold. Level detection and drainage are required.

Inter-cooler / After-cooler

Reciprocating compressors often achieve the required compression ratio in one stage, the hot discharge gas is then often cooled to drop out gas liquids which will otherwise condense out in the discharge pipework. Where two or more stages of compression are required, an intercooler may be installed, requiring associated liquid knock-out arrangements.

Recycle Valve & Capacity Control Options

Fixed speed reciprocating compressors have a fixed suction volume flow. For start-up purposes, and to control capacity, discharge gas is often returned to suction through a recycle valve. When a high proportion of the flow is recycled, it is important that the flow route includes a cooler. Either the normal after-cooler or a dedicated recycle cooler may be used.

Recycle control achieves good controllability but is expensive, as the power consumption is not reduced. Three other control options are used on reciprocating compressors :-

Suction valve unloaders are mechanical devices that force selected suction valves open, thus unloading one or more cylinders. This removes most of the load from that cylinder, reducing the power consumption. The unloading mechanism adds complexity and can reduce the service life of the suction valves. Unloading systems must be designed and maintained with care as they can alter the gas loadings on the motion works and cause bearing damage.

Clearance pockets are mechanical devices that alter selected cylinder clearances, changing the volumetric efficiency and thus the throughput. This reduces the power consumption of the compressor but can increase the gas temperature and again can cause bearing damage if wrongly applied.

Finally, variable speed is an excellent way of achieving capacity control, with a reasonably linear reduction of capacity and power with speed, over a reasonable speed range. Torque remains

essentially constant with speed, which may limit the use of standard variable speed electric motors. One potential disadvantage of variable speed is the generation of pulsations at varying frequencies, it is likely that one or more speeds will excite mechanical or pipework natural frequencies.

Barring Gear

Manual barring of reciprocating compressors is normally carried out for maintenance purposes, though in some cases this is also required for process operations. Where manual barring is required the task should be covered by the appropriate isolation requirements for work. Some machines are equipped with an interlock switch on the barring gear access cover, though it is not good practice to rely solely on such interlocks for an activity which involves the operator in contact with the machine.

Where it is required to be able to rotate a reciprocating compressor very slowly, so that it can be stopped in the correct position for maintenance or inspection, this can be done mechanically. This equipment is referred to a "Barring Gear". Normally some form of mechanical or hydraulic drive is required. It must be recognised that operation of barring gear is often done with the machine isolated and partly opened up, within the Permit to Work, and can pose major injury risks despite the very low speeds involved. It is best if this equipment is fully disconnected from the compressor motion works, (usually the crankshaft) and guards fully replaced, prior to attempting a normal machine start. Because of the high gearing or leverage ratios involved, any barring gear engaging at normal speeds may be violently ejected from the machine, together with supports / casings.

For further information on Ancillaries and related hazards see **Section 5** – Ancillary Systems & Equipment.

4.4.6.10 Control & Management Systems

The main control requirements will be dictated by the function that the compressor must perform. Flow control, suction pressure or discharge pressure control are common. Control may be done within a dedicated PLC or a plant DCS system. Parameters to be managed may include shaft speed, suction (or discharge) throttle valve control, and recycle valve control. Shaft speed control is achieved by a link to the driver control. Unloading systems will operate as sub-functions as they tend to have a step-wise action. Where compressor loads do not change significantly, the unloading can be done manually, making the control system much simpler.

Reciprocating compressors do not suffer from surge. Instead they often have limitations on maximum and minimum cylinder pressures and balance of pressures across each cylinder, otherwise the motion works and bearings are overloaded. Similarly there is an effect called "rod reversal" which is required to ensure bearing lubrication. These pressure limitations should be input into the control system and used to ensure satisfactory operation while minimising power consumption as far as possible.

Lubrication and seal service system controls. These are normally simple mechanical controls to maintain pressure, flow, and temperature of services. Loss of pressure will normally cause a compressor trip.

Process gas isolations are normally achieved using manual valves. This should be by "double block and bleed" principle, slip or spectacle plates should then be used for positive isolation. Automatic isolation and vent to flare on trip is quite possible. The use of power operated valves for process isolation requires additional care to ensure that the valve has actually closed (not just the actuator) and that it cannot open again. This may require disconnecting linkages or air supply pipes. Air operated valves can open or close with tremendous force if air pipes are connected or disconnected inadvertently.

4.4.7 INTEGRATION ASPECTS

- ***Gas Compressors are specifically designed for a process duty; unexpected process conditions can cause rapid deterioration. If this overloads or disrupts the motion works it can cause a direct hazard.***

- ***Reciprocating compressors cause pressure and torsional pulsations at multiples of running speed. These pulsations can affect other associated equipment.***

- ***Good alignment is well worth the effort, alignment errors can increase wear and fatigue effects.***

- ***Relevant condition monitoring can assess the health of the unit and defer expensive and invasive maintenance.***

- ***Protective systems are fitted to prevent machine damage, and, more importantly, prevent a failure resulting in a gas release.***

- ***Modern compressors are fitted with sophisticated bearings. With good crankcase lubrication and periodic inspections, the bearing system should have a very long service life.***

- ***The cooling requirement on a gas compressor itself is of the lubricating oil and cylinder walls and is quite simple. The gas cooling can be more complex as it has to match process loads.***

- ***Sophisticated gas sealing systems are used. High quality maintenance using appropriate tools and techniques are required to achieve good service lives.***

4.4.7.1 Process Duties

Since process gas compressors are designed for a chosen duty, it is important that the vendor be aware of, and understand, the full envelope of the duty. It is also important that any proposed extension of the operating envelope be explored with the vendor. Fortunately, changes in load resulting from changes in molecular weight or inlet pressure, will normally be limited by the machine controls. Problems will occur if changes are rapid, or if instruments are designed on the assumption of a fixed gas composition or inlet condition. The safety concerns relate to the possibility of ingesting liquid, or overloading the motion works.

Liquid ingestion, covered in **Section 4.4.3.1** above, can cause damage or fouling. Liquid slugs must be avoided, as they can cause major damage.

Gas recycle is often used for load control, because reciprocating gas compressors are essentially constant suction volume machines. It is good practice to design such a system for continuous operation at full recycle. It must be recognised that this is a huge waste of energy, which can be reduced by variable speed, suction throttling and unloading systems. It is necessary to remove the heat of compression from the recycle gas, this may be by use of the normal in-line gas coolers, or by using dedicated recycle cooler(s). Any condensed liquids must be efficiently separated.

Intercoolers may be used on multi-stage compressors to improve compression efficiency and limit discharge temperatures. If the intercooler is ineffective, operating temperatures in the

downstream stage will be excessive, which could result in mechanical problems, such as valve or piston ring jamming. The intercooler will often condense liquid, if this is re-entrained, particularly as slugs, damage to the downstream stage could result. If the intercooler tubes leak, the downstream stage could be contaminated with salts from the cooling water.

4.4.7.2 Mechanical Integrity

Reciprocating compressors are large, complex machines with many mechanical joints in the pressure-containing envelope. The individual components are quite robust but the overall machine is vulnerable to damage and leakage particularly if subject to excess vibration or mechanical loads as a result of poor operating or maintenance practice. There are a number of critical fasteners, some of which are internal thus inaccessible in service. Failure of internal fasteners can in general lead to failures of the motion works, with a chance of sufficient consequent damage to rupture the containment. Failure of external fasteners will generally loosen or release access covers, those over the valves will permit a large gas release, those on the crankcase will leak oil but should not cause a serious hazard.

All connections, including motion work connections, major machine components – valve covers, cylinder head etc., and all structural and foundation bolting, within a reciprocating compressor are subject to vibration. Maintenance standards and practices must ensure that none of these connections loosen in service, and re-inspection intervals and checks need to be carried out to confirm the standards are achieved and maintained.

Reciprocating machines are built up around a central crankcase housing the main motion works with the process gas contained within a series of cylinders mounted either directly or indirectly on the crankcase. Maintenance inspections of this assembly are equally as vital to the reliability and integrity of the machine as with any of the pressure containing parts.

The pipework and (heavy) pulsation dampers will be subject to mechanical vibrations, which can strain bolted connections and supports. On complex systems, the piping will require stress analysis to confirm that thermal expansion will not over-stress the pipework and fasteners. The pipework may require to be set up with some pre-loading ("cold pull") to anticipate this expansion.

Fasteners should be subject to periodic inspection, replacement by programme or inspection-based, all new and replacement fasteners to be of vendor original or approved material and manufacture. Where critical fasteners are in blind holes, procedures must ensure that the threads are inspected, and that the correct lengths of fasteners are used (too short, fastener could pull out under load; too long, fastener bottoms and does not fully close the joint).

Internal clearances are often very small, the critical ones are those at either end of the piston travel. If the clearances are wrong, the piston can hit the cylinder end in service, causing major mechanical damage.

4.4.7.3 Alignment

A gas compressor whose motion works are well-aligned will run smoothly with minimum bearing loads.

Thermal expansion of the compressor, the driver and the baseplate cause the alignment to change. In addition, thermal and gas pressure loads are applied by the process pipework. The normal design arrangement is for the crankcase to be supported at its base, cylinders to be supported on stools, and with the pipework supported to achieve flexibility. Provided that the thermal expansions are repeatable, the "cold" alignment is made with offsets for predicted expansion. This is a highly skilled job, preferably using laser alignment tools.

4.4.7.4 Condition Monitoring

Reciprocating compressors benefit from condition monitoring to trend the health of internal components. The value of the process is usually so high as to justify quite elegant continuous monitoring. However, it is more important that whatever the installed system it works, is understood and is used properly.

The major health check on a reciprocating compressor is on the valve temperature measurement and trending. As this cannot be done in isolation of the process conditions this needs to form part of operational monitoring.

Vibration level monitoring on reciprocating compressors is difficult to interpret and as a form of effective condition monitoring requires a benchmark measurement, trending, alert and action levels for each parameter. A single measurement in isolation gives little information.

Assuming that the process system in question is being controlled by a DCS system, the recording and trending of process parameters can provide information on compressor health. For example, capacity change usually indicates wear or valve damage and discharge temperature points to valve or cooling problems.

"Traditional" condition monitoring measures cylinder vibration, rod drop and vibration and temperature at bearings. Crankcase oil should be sampled on a routine basis. Where this can be trended and compared with compressor duty, a good understanding can be gained of the compressor's health. Infra-red scanning with a camera can often identify valve problems; skill and practice are required. A set of “as new” photographs is very valuable as even new machines will not have identical temperatures on all cylinders.

4.4.7.5 Protective Systems

Systems providing alarm only action should be subject to periodic testing, however delays to such tests, or known calibration errors, do not cause a direct safety risk and can be managed. Trending of the data prior to an alarm coming in can give valuable pre-warning; intelligent use of combined trends can indicate developing fault conditions.

The compressor must operate with closely defined parameters, the protection provided will be designed to suit a particular installation, a typical installation may include :-

- Low suction pressure
- High suction pressure
- High interstage pressures
- High discharge pressure
- High differential temperature
- High suction temperature
- High discharge and interstage temperatures
- Gland leakage detection
- Vibration levels for each cylinder
- Motion works lubrication oil pressure
- Lubrication flow to gland and cylinder
- Bearing temperature protection

These are measured and protective action automatically initiated when the machine exceeds defined levels. The safety protective systems require tests and, must have a checked return to operation after test. Trip test procedures must be validated and adhered to. Trips may be disabled during machine start - ideally the measured values are recorded at high sample rates during a start, for examination should there be a problem. Also the enabling process must be

validated - particularly on a new machine or after software / instrument modifications. Failure of a single trip should not lead to an unsafe condition - a problem is likely to be detected in several different ways, and the machine tripped before a dangerous condition is reached, though there may be some internal damage e.g. to a bearing.

Process Isolations

As referred to in **Section 4.4.3.1**, upstream and downstream process isolation valves should be tripped closed on a machine trip. In addition, there should be a self-acting non-return valve. These valves prevent reverse spinning, and minimise the extent of a process gas release from a damaged machine. Similarly if there is a process system trip, this may require the compressor to be tripped. If the trip is not safety-related, it may be delayed while vent / purge actions are completed.

Use of Software Trip Systems

While it is recognised that the reliability, cost-effectiveness and sophistication of modern digital control systems mandates their use for the management control of complex plant equipment, the risk of common systems failure must be accepted. Key trips (e.g. seal pressure, oil pressure) may justify duplicate hard-wired trips. Software trip sequences require rigorous change control procedures. This is true even of "vendor standard" upgrades, particularly on process systems which have probably been "tailored".

The three most critical protective systems on reciprocating compressors are :-

Low Suction Pressure Trip. This can prevent excessive differential pressures, which can overload the piston rods, also unintended sub-atmospheric operation can draw air in through vents or valve glands, potentially creating an explosive or corrosive mixture.

Discharge Relief Valve(s). Positive displacement compressors can create dangerously high discharge pressures, particularly if the suction pressure is allowed to rise higher than normal (e.g. blocked discharge, low flow, gas source continues to supply, suction pressure rises, discharge pressure rises to dangerous levels). The compressor should have a discharge pressure trip which acts first, but the relief valve(s) is the ultimate protection. There should be a system to alert the operator when the valve lifts.

Low Lubricating Oil Pressure. Lack of oil to the motion works will lead to major bearing damage. One or more oil pressure switches, located remote from the pump, should bring in standby oil pump(s), finally trip the compressor. Loss of oil pressure may be the first indication of major compressor damage.

4.4.7.6 Bearings

The bearings in gas compressors are dependent on a continuous supply of oil for lubrication and, more importantly, cooling. Generally, oil must be pressure-fed prior to machine start, and continue to flow until the machine has fully stopped. Reciprocating compressors stop very quickly, but it is good practice, on a normal stop, to leave the oil pump running for a few minutes to cool the bearings. Hence possibly a selection of oil pumps, driven by AC power, machine shaft. Oil quality in terms of grade, cleanliness, low moisture content, temperature and adequate flow are vital. Oil grades, even "equivalents", should not be mixed without draining the complete system.

Radial bearings are large plain white metal type, to suit low speed and high loads. Temperature sensors should measure bearing metal temperature, not the oil.

There should be no thrust loading on the crankshaft, simple thrust rings will be fitted to one of the main bearings to limit axial travel to perhaps 0.5 mm.

The “little end” bearing, linking the connecting rod to the crosshead, is special as it has a reciprocating loading with very little rotation. If the loading does not reverse with every stroke, the oil film will fail and the bearing will wear rapidly. This reversal will be established as part of the design process, unloading systems must work correctly as designed or the reversal effect can be lost.

For details of Bearings and related hazards see **Section 5.9** – Ancillary Systems & Equipment.

4.4.7.7 Cooling

The main obvious cooling requirement on a gas compressor is the lubricating oil; this can be cooled against air or water. Loss of cooling effect normally results in a controlled trip with no safety implications. A cooler tube failure can be more subtle - air cooled tube failure can spray oil mist causing a fire risk, water tube failure can contaminate the oil causing rapid bearing failure. The cooler design should permit tube inspection / testing, corrosion resistant materials must be used, and gasketed water / oil joints avoided.

Cylinder walls and piston rod packings are cooled to remove frictional heat. This cooling should be established just before start-up, but not left on when the compressor is stopped, as it can cause condensation.

The process gas coolers (inter, after, recycle) provide a cooling load dependent on process duty requirements. The cooling load may be massive (of the order of the compressor drive power) thus taking a considerable part of the plant's available cooling capability. Any limitation in cooling will give higher than intended gas temperatures, reduced compressor efficiency. Provided that gas cooler inlet and outlet temperatures and pressures are available, loss in cooling performance can easily be detected and creates no hazard. Carrying out an energy balance across a cooler is notoriously difficult, cooling water flow measurement is seldom anything like accurate enough. For details of Cooling Systems and related hazards see **Section 5.11** – Ancillary Systems & Equipment.

4.4.7.8 Sealing

Piston Sealing

Piston seals are split ring seals, sprung against the cylinder or liner wall. Faults with the seals will lead to loss of performance but no hazard. Broken parts of piston rings will probably jam in the discharge valves.

Piston Rod Seals

These seals control the leakage of process gas to vent / flare, normally aided by an inert gas buffer. Multiple seals are used failure of one element will have little effect. General failure, possibly caused by piston rod coating failure, or crystalline gas deposits, will increase the loss rate beyond the vent capacity. This will pressurise the distance piece and eventually the crankcase. All covers should be rated to withstand any realistic back pressure, and the compressor should be tripped as soon as the pressure starts to rise. The seals are precisely engineered items normally supplied in a cartridge format, requiring skill in assembly and fitting.

Failure of seals may be progressive with designs allowing for detection of deterioration by measuring leakage rate at different positions along the seal. Action should be initiated, once the seal has started to deteriorate, to carry out planned maintenance; significant leakage can occur if the early warnings are not observed and acted on.

The seal design relies on a series of rings acting in concert to reduce the pressure of the process gas over a series of stages. These are normally supplied as a cartridge assembly to be

carefully fitted into the machine. In some cases, possibly as a result of a series of early failures, in situ maintenance can cause a rapid worsening of the problem. In particular failure of the joint between the seal cartridge and the machine cylinder, which should normally be replaced at each seal removal requiring removal and refitting of the piston rod, can occur if the joint is poorly fitted or is reused. As this joint sees the full discharge pressure of the cylinder it can give rise to significant leakage.

Static Seals.

All covers should be sealed by O rings or fully retained gaskets. Cover fasteners must be tightened evenly and progressively to the correct torque, special fasteners are not normally used here. Seals / gaskets should be renewed, not re-used.

Crankshaft Oil Seals

For details of Oil Seals and related hazards see **Section 5.3.5**.

4.4.8 CONTROL

- ***The process control system will be set up to achieve the required duty at minimum practical energy usage.***
- ***Should effective control fail, the compressor may be overloaded. Pressure sensors should detect this and trip the machine.***
- ***Support services will be linked by a simple permissive logic system.***
- ***Bearing monitoring will raise alarms first, followed by trip action if conditions worsen.***
- ***Control systems should be subject to a formal change control process.***
- ***A structured trip test programme is part of the appropriate maintenance strategy.***
- ***Significant changes in the process duty may require control system changes.***

The process control of the compressor will be set up to achieve target parameters in the gas flow, e.g. pressure, flow, at the least practical energy usage. This may involve recycle control, speed control (signal to driver) and compressor unloading control.

There will be a simple logic control to ensure that services like oil and seal pressure are maintained. These must be established prior to start, and reduction in e.g. oil pressure will raise an alarm and bring on a spare pump. Loss of such services will trip the compressor. Operating the compressor with such trips defeated is unsafe.

Process gas temperatures, cylinder vibration and bearing temperatures will raise alarms first, may then trip as conditions worsen. Tripping on vibration can be a headache as some bearing & sensor systems are sensitive and prone to spurious trips.
The trip and alarm facilities should be subject to a formal change control process, with clear definition of which (if any) changes may be made without manufacturer approval. Similarly the

manufacturer's (or other) service engineer should not be permitted to change settings or software without formal record.

The operators require a clear understanding of which alarms/ trips are over-ridden during start, and why. Test procedures are required to validate that the important trips are re-enabled at the correct time. Formal testing and recording of alarm / trip tests, at intervals defined by or agreed with the manufacturer, are required. If tests are done with the machine on line, it must be recognised that the trip is disabled during the test, and that a partial test only is possible.

The control system will initially be configured to suit the intended duty of the machine. Should the duty change significantly, the control system may have to be re-configured to achieve effective results. Difficulties in controlling the recycle flow, or relief events, indicate a problem in this area.

4.4.9 ANCILLARIES

- ***Ancillary equipment should not pose any great hazard.***
- ***Twinned items may be serviced on line, with due care and appropriate instructions.***
- ***Lubricating oil backup systems should be tested off-line by simulating a trip.***

The range of ancillary equipment should not pose any great direct hazard, provided normal design, maintenance & inspection procedures are followed. Particularly during machine start / stop, ancillaries may start without warning. Where valve actuators and spindles are readily accessible, it may not be common practice or indeed practical to fully guard them. Consideration needs to be given to the relevant risk of a hand or arm trap while working in a confined space. Some form of shielding may be more appropriate than fitting a full guard.

Where certain ancillaries e.g. filters, oil pumps, are twinned, it is possible to service or remove one unit while the compressor is on line. The operating instructions must cover the attendant risks of operating with one such unit unavailable, and the potential consequences of an incorrect changeover. One example is putting an oil filter on line without priming it, the lubricating or control oil supply may be interrupted. Instructions and, if necessary, labels, may be required if changeover valves must be operated in a particular sequence, or can readily be mal-operated.

It is normally ill advised to run with ancillary oil pumps out of service, as failure of the operating oil pump may lead to major machine damage to bearings. Reciprocating compressors have high bearing loads and the bearing surfaces are an integral part of major components such as the crankshaft and cross head; damage to these components can be costly and require extensive maintenance activities to repair.
Some compressor installations have header tanks or pressure accumulators to provide lubricating oil for run-down in the event of complete power failure. These systems only work if the tank/ accumulator is full, the relevant valves are open, and the drive is tripped immediately the main oil supply is lost. The gravity oil flow is not sufficient for full speed / load operation. As live testing of such systems can cause significant machine damage, it is prudent to carry out simulated tests with the compressor stopped. If the oil supply lasts longer than the run-down time, one can be confident of effective operation. It is very costly to wreck a compressor to prove that the run-down system did not work.

SECTION 4.5

RECIPROCATING COMPRESSOR (AIR SERVICE)

CONTENTS

The target duty is the production of oil-free air for distribution to instruments and other clean services. Reciprocating compressors are commonly used for small to moderate air flow rates.

4.5.1 INTRODUCTION

See **Section 4.2.1** for a general introduction to Instrument Air Compression.

Additionally :-

Reciprocating compressors can achieve high pressure ratios per stage at low volume flows. They are used for smaller flows than screw and centrifugal compressors, and offer greater flexibility of duty than, in particular, centrifugal compressors. They are mechanically significantly more complicated than centrifugal compressors.

Reciprocating compressors comprise sets of one or more compression cylinders, each with a matching piston. Process compressors are designated as Horizontal or Vertical design according to the orientation of the cylinder centre-lines. Service compressors (typically on instrument air duty) may have different orientations referred to as V, W, L, but these complex options are not used on process units.

Compressors require suitable piping, interstage vessels and coolers with associated control systems. Together with baseplate and driver this forms the "Compressor System".

The vast majority of compressors are shaft driven by a separate electric motor, gas turbine or diesel engine. A drive gearbox may be required to match the compressor and driver speeds. Reciprocating compressors are not normally variable speed as there are a number of ways to modify the output from such machines including :- reducing cylinder efficiency using clearance pockets, control on suction valve opening, and offloading cylinders.

4.5.2 BACKGROUND & HISTORY

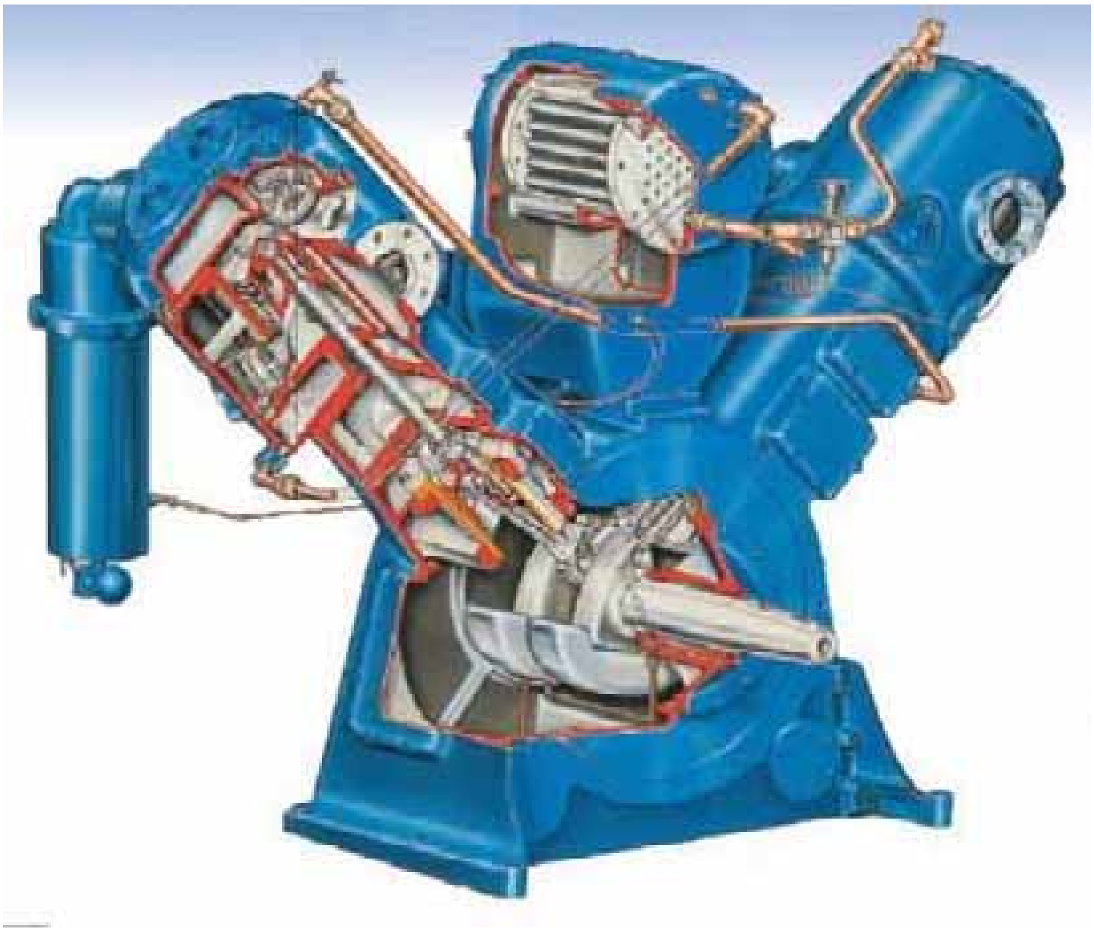


Figure 4,5 – 1 Two Stage Reciprocating Air Compressor (Cut-away)

- ***Most early air compressors were of reciprocating design, more recently screw compressors have become popular for many applications. Reciprocating compressors are still used for small demands.***
- ***Early compressors had oil lubricated cylinders. More recently, instrument air compressors have "dry" cylinders.***
- ***Air compressors are usually vertical or "Vee" configuration, often with a belt drive.***
- ***Typical reciprocating air compressors have shaft speeds in the range 500 - 1000 rev/minute and are supplied as packaged units.***

Air compressors have been in use for well over a hundred years, early designs were primarily of reciprocating design. The basic design has changed little, but improvements in materials, seals and design principles have significantly improved the service life and reliability. Although screw and centrifugal compressors are now available, low flow duties still suit reciprocating compressors.

Reciprocating compressors consist of a rotating crankshaft, linked to a number of piston rods by connecting rods. Each piston rod passes through a set of packed rod seals, into the compression cylinder. The rod carries the piston, which moves in the cylinder bore in a reciprocating manner. Pistons are normally double acting (compression on out and return strokes) Gas inlet and exhaust is via plate, ring or poppet type valves.

The crankshaft runs inside an enclosed crankcase, in multiple bearings. The crankshaft end of the piston rod is also inside the crankcase, this is supported by a sliding "cross-head bearing". These bearings are oil lubricated, pressure fed by a pump.

Early compressors has oil lubricated cylinders thus, inevitably, oil in the air. Even with good filtration, there will always be traces of oil. For many years now, "dry" designs have been available which use carbon and/ or PTFE as a solid lubricant within the cylinder and rod packing. These produce oil-free air.

Air compressors may be of vertical design, but one particularly popular design is of "Vee" configuration. This gives a small footprint and simple installation.

Typical shaft speeds are in the range 500 – 1000 rev/min. Drive may be by a close-coupled motor, although vee-belt drives are common.

4.5.3 HAZARD ASSESSMENT

- ***The hazards associated with a compressor have to be considered over its complete operating/ maintenance cycle, not just full steady load operations. Mal-operation / excursions / drive system failures and emergencies must all be covered. The hazards must be seen in context with the installation as a whole, and be compared with alternative compression strategies.***

4.5.3.1 Process Substance Containment Hazards – Air

See **Section 4.2.3.1**, which is equally applicable to reciprocating compressors.

4.5.3.2 Equipment Hazards

The reciprocating action of the motion works imposes a variable torque on the crankshaft, the total effect is that most parts of a reciprocating compressor are subject to fatigue conditions at 1 or 2 cycles per revolution. A failure of the crankshaft, connecting rod or cross-head has the potential to breach the crankcase and eject major parts. This will release a quantity of lubricating oil and may permit back-flow of compressed air from the delivery manifold. Failure or partial failure of the crankcase could displace cylinders leading to very high vibration levels which can rupture pipework, flanged connections, and foundation bolting.

Within the cylinder, loosening or failure of the piston nut or cross-head nut can cause the piston to be driven against the end of the cylinder, breaking the cylinder end or bending the piston rod. A bent or unsupported piston rod could then wreck the piston rod seals. Failure of a valve cover or valve retainer could cause ejection of a valve complete with cover.

Oil feed pipes to bearings are at relatively low pressures (3 - 5 barg) but can drip or spray oil if damaged. The oil may pose personnel risk (toxicity, spray in eyes, or as a slipping hazard) or catch fire from a hot surface. Compressor metal temperatures are unlikely to be high enough, except as a result of ongoing bearing failure. A failed or failing crankshaft bearing can generate sufficient heat to ignite oil. Opening a crankcase cover can let fresh air contact hot, oily, metal, provoking a fire or explosion, procedures should allow cooling of the machine so that by the time the equipment has been isolated and covers removed the hazard is no longer present. Sets should not be run with crankcase covers loose or partly bolted, as these could be blown off. It is good practice to fit crankcase explosion relief valves.

A compressor can be driven backwards e.g. by incorrect electrical connections to the motor. The compressor will run and will compress air, but the bearings and lubrication system are not intended for reverse running and will be damaged. The shaft driven oil pump, if fitted, may well not work if run backwards.

4.5.3.3 Operational / Consequential Hazards

Reciprocating compressor with oil lubricated cylinders either by direct injection of oil to the piston or lubrication from crankcase have a particular hazard associated with oil air explosions. The hazard is present when a combination of carbon contamination and the oil air mixture becomes too hot initiating an explosion in the machine or discharge system (pipes and vessels). Stringent procedures to limit compression temperatures (normally less than 160 C), correct choice of oil (low carbon formation), and inspections for carbon build up are needed to avoid such events.

For dry (non lubricated) compressors See **Section 4.2.3.3**.

4.5.3.4 Maintenance / Access Hazards

The standards of maintenance for reciprocating compressor must be maintained at the highest level. Reciprocating compressors are vulnerable to incorrect mechanical standards, these can lead to rapid deterioration and failure of components leading to potential for disruption of the machine. Examples of this are -:

- Correct assembly and fitting of the self actuating machine valves is crucial to machine operation. Though such valves are normally designed to be unique to a particular position and duty on the machine it may still be possible to confuse the installation. In such cases this can cause the machine to be gas locked with catastrophic results. Machines returning from external maintenance may require preservative actions to be reversed and the removal of dessicant bags from valve ports is also vital.
- Incorrect bearing clearances – on crankshaft this has led to failure of the crankshaft and major machine disruption.
- Incorrect set up for piston rod connections either for cylinder or crosshead can cause complete failure of piston rod.
- Wrong maintenance standards applied to recover wear on piston rods have caused rod failure.
- Wrong maintenance standards applied to recover wear on crankshafts has resulted in failure of crankshaft.

These compressors are maintained in situ, requiring effective lifting facilities and laydown areas.

Compressor control panel and ancillaries may be located on the same skid, or adjacent, or in a control room.

4.5.4 OPERATING REQUIREMENTS

- ***Reciprocating air compressors are generally designed for periods of steady operation, typically with an annual overhaul. Valves and seals require service at perhaps 3 or 6 monthly intervals.***

Generally, see **Section 4.2.4**.

4.5.5 MAINTENANCE REQUIREMENTS

- ***Reciprocating compressors are designed to be maintained in situ. Seals and valves can be removed and replaced as assemblies. Major parts e.g. cylinders, crankshaft, require lifting facilities.***

Maintenance requirements for reciprocating compressors are a combination of preventative maintenance of the motion work and major components and essential predictive maintenance based on measured performance such as valve temperatures, rod drop, vibration.

Valves, rod seals, bearings can be accessed by removal of local covers. Removal / maintenance of seals and bearings requires lifting equipment to support and position motion work as required. The pistons and rod are normally removed as an assembly by unscrewing the cross-head nut. Only then can the rod seal, and the piston rings, be inspected and changed. Reciprocating compressors are thus relatively maintenance-intensive, reducing the availability compared to screw compressors.

4.5.5.1 Internal Corrosion

Compressors which have been out of service for some time, particularly if left open to the weather, can suffer major corrosion damage. Hence standby machines should be regularly be brought into service for a minimum of 24 hours, and machines which are out of service should ideally be sprayed inside with a light coating of lubricating oil, protected from the weather and purged with a small flow of dry air. Note that the compressor must be run to the Service Air manifold, or to atmosphere via a filter, for several hours to remove all the oil, before going back into instrument air service. The crankcase and cross-head areas will be reasonably well protected by the lubricating oil, particularly if the unit is test run on a regular basis.

Figure 4,5 – 2 Reciprocating Air Compressor Second Stage Cylinder. Note protection over hot discharge pipe.

4.5.6 RECIPROCATING AIR COMPRESSOR MAIN COMPONENTS

Reciprocating air compressors are similar to process gas compressors, see **Section 4.4.6**, but are somewhat simpler. Specifically :-

- Piston rod seals are simpler as only air is vented.
- There is only a simple distance piece to carry the rod seal & oil seal.
- The crankcase atmosphere is air.
- "Dry" compressors use carbon/ PTFE seal rings, piston rings and piston rider bands, so there is no cylinder lubrication system and no oil drains.
- There is no recycle valve, instead excess air is vented (via a silencer).
- Unloader control is common, using mechanical devices to force open selected inlet valves.
- Intercooler and lubrication system tend to be integral to the compressor.

See **Section 4.2.6.9** for Air Dryers. See **Section 4.2.6.10** for Control & Management Systems.

4.5.7 INTEGRATION ASPECTS

- ***Instrument Air Compressors are near-standard packaged units; oil-free designs are preferred.***
- ***There is little scope for mechanical tailoring, any interference with the vendor's design imposes cost and time penalties.***
- ***Relevant condition monitoring can assess the health of the unit and defer expensive and invasive maintenance.***
- ***Reciprocating air compressors are normally water cooled.***
- ***Relevant condition monitoring can assess the health of the unit and defer expensive and invasive maintenance.***

Since instrument air is a "utility" service, cost-effective packages are available almost on a "ready to run" basis. They do not comply with onerous oil industry or vendor specifications. Dry compressors are preferred to ensure oil-free air. Compressors built to industry or vendor specifications would in effect be process gas machines, on a price and delivery to match.

Vendors build ranges of compressor capacities and pressure options to suit the market. A limited degree of tailoring can be done. Air compressors are generally installed in weatherproof buildings with some degree of heating or at least frost protection. Condition monitoring should be done as a routine part of the maintenance/ service package.

Protective systems are fitted to protect against machine damage through loss of oil pressure, or excessive temperatures. Each compressor stage should have its own relief valve. Equally, the relief valves must be tested.

Reciprocating air compressors have cooling jackets around the cylinders, an oil cooler and inter/ after-coolers. It is convenient to use a circulated fluid, normally closed circuit fresh water, as the coolant. Heat can then be exchanged against air or, more compactly, water. Air cooling requires a significant cooling air supply and a significant radiator area as the heat to be lost equates to the compressor motor power.

Oil-flooded screw compressors lose most of their heat directly into the oil, which can then be cooled against air or water.

4.5.8 ANCILLARIES

Lubrication System

The lubrication system of a dry reciprocating compressor is fully self-contained and should not come into significant contact with the compressed air. Hence the oil should stay clean and can be sampled and checked for contamination e.g. from damaged bearings. An oil pump, filter and oil cooler are normally fitted, to supply clean cool oil to the bearings and crosshead. The main oil pump is often shaft driven, for simplicity. A small motor driven pre-lubrication pump may be fitted. Loss of oil pressure must trip the compressor.

For further information on Lubrication Systems see **Section 5.2**

Cooling System

A water-based cooling system is expected to cool the circulating jacket water against sea water. The sea water will be supplied from a utility manifold and returned to open drain. A pump will be required to circulate the jacket water. This pump should be interlocked to the main motor starter.

An air cooling system will require a plentiful supply of clean air from a safe location, this will normally be the same as the air supply for the compressor air intake. A ventilation fan will be included in the compressor package, but additional fan(s) may be required if the air inlet and outlet are restricted by ducts.

SECTION 4.6

PUMP – GENERIC

CONTENTS

This report section describes Dynamic and Positive Displacement pumping principles and the application of these principles to generic pump types. The information applies to common centrifugal pump types and is referred to from other sections, to avoid duplication.

4.6.1 INTRODUCTION TO PUMPING PRINCIPLES

- ***Pumps are used to transfer, or increase the pressure of, liquids.***
- ***Dynamic pumps work by sequential acceleration and deceleration of the working fluid.***
- ***Positive Displacement pumps work by transferring measured quantities of fluid from pump suction to delivery, against a pressure differential.***
- ***Centrifugal pumps are the most commonly used type of Dynamic pumps, using one or more stages in series.***
- ***Single stage pumps are simple robust pieces of equipment and can run for extended periods without problems. Mechanical seals remain the most vulnerable area.***
- ***Multi-stage pumps are more complex and require higher standards of design and build for extended operation.***

4.6.1.1 Working Principles of Dynamic and Positive Displacement Pumps

There are two fundamentally different principles used to pump liquids.

Positive Displacement Pumps :- devices which move packages of liquid through the pump, transferring discontinuous packages from a lower pressure source to a higher pressure receiver.

Dynamic Pumps :- devices which add energy (normally in the form of velocity) to the pumped fluid and which subsequently allow this energy to translate to pressure / liquid flow in a continuous process.

Positive Displacement pumps are discontinuous flow machines, they induce a fixed volume of fluid into a pocket, chamber or cylinder for pumping, by increasing the pocket volume mechanically. The pocket is then closed to suction & opened to discharge. The pocket volume is then reduced mechanically, forcing the fluid to be discharged from the pump at the pressure of the receiving system, normally at higher pressure. Only one stage of this mechanical displacement process is normally required, though to increase capacity, balance flows and compression forces there can be a series of pumping stages acting in parallel, but out of phase. There is never an open flow passage from delivery to suction (except for leakage through the clearances between moving parts).

Typical machines are :-

Piston pumps
Screw pumps
Gear pumps
Lobe Pumps
Diaphragm pumps
Progressive cavity pumps.

Piston, Diaphragm, or Plunger pumps use one or more reciprocating pistons in cylinders to pump fluid from a low pressure to a higher pressure. Self-acting suction and delivery valves permit forward flow and prevent back flow through the pump. The moving piston is sealed to the cylinder by specialised gland packing systems. The reciprocating motion is normally driven by a crankshaft, but can be operated directly by a pneumatic or hydraulic cylinder. A single reciprocating cylinder inevitably introduces pulsation, some capacity regulation systems make this worse by physically stopping the piston at a part stroke position. Triplex pumps have 3 cylinders with crankshaft driven pistons phased at 120 degree intervals. This minimises pulsation. Otherwise "pulsation dampers" can be fitted. These contain an elastomer bladder pre-charged with compressed gas, and absorb pulsations by further compressing the gas. Pulsation dampers are notorious for creeping deterioration in performance.

Screw and progressive cavity pumps use one or more helical screw shafts, these rotate continuously, drawing fluid up as the screw turns. To prevent back-flow, matched sets of screws seal each other, or a single screw runs in a soft moulded rubber stator. The clearances between screws and between screw and stator are critical, any wear here causes permanent loss of performance. Most screw pumps require the use of an inherently lubricating fluid to minimise wear. Certain special designs, which are more complex, can handle non-lubricating fluids and fine solids in suspension.

Gear pumps transport liquid in packages using simple meshing gear sets in close fitting casings to seal against back flow whilst the gear teeth transfer normally relatively viscous fluids, typically lubricating and heavy oils, around the gear periphery.

Lobe pumps use meshing pairs of lobed rotors, these are similar to gears but only have two or three lobes or "teeth" per rotor. To prevent lobe-to-lobe contact, they have an integral timing gear set. Lobe pumps can pump viscous non-lubricating fluids.

Peristaltic Pumps are an unusual and non-typical Positive Displacement pump design. They work by squeezing a soft rubber hose to create a seal, then moving the squeeze forward, mimicking the peristaltic pumping action of the human gut. In process pumps, the hose is curled into a pump casing and the squeeze is driven by cams or rollers mounted on a central rotor. These pumps are used for low-flow pumping of shear-sensitive fluids.

Dynamic Pumps are continuous flow machines, they use rotating impellers or propellers to sequentially accelerate the liquid (increasing its velocity) then decelerate it (trading kinetic energy for increased pressure). This may require a number of stages (maximum about 10), often within the same casing. Dynamic pumps always have an open flow route through the machine.

Typical machines are :-

Centrifugal Pumps
Axial Flow Pumps
Hybrid (Mixed Flow) designs also exist.

Centrifugal Pumps are by far the most commonly used dynamic pumps.

Centrifugal pumps work by spinning an impeller submerged in a bath of fluid. Vanes on the impeller impart rotary motion to the fluid, centrifugal effects push the liquid towards the outer edge of the impeller. This displaced liquid leaves the impeller and is collected by the shaped volute, which decelerates the fluid, converting kinetic energy to potential energy. This potential energy is expressed as increased pressure. The liquid being displaced from the impeller creates a partial vacuum at the centre of the impeller, permitting more liquid to enter from the pump suction. The impeller is a close fit in the casing to reduce the amount of back-flow which will by-pass the impeller. Centrifugal pumps may include several stages in series, each comprising one impeller, stage casing and volute.

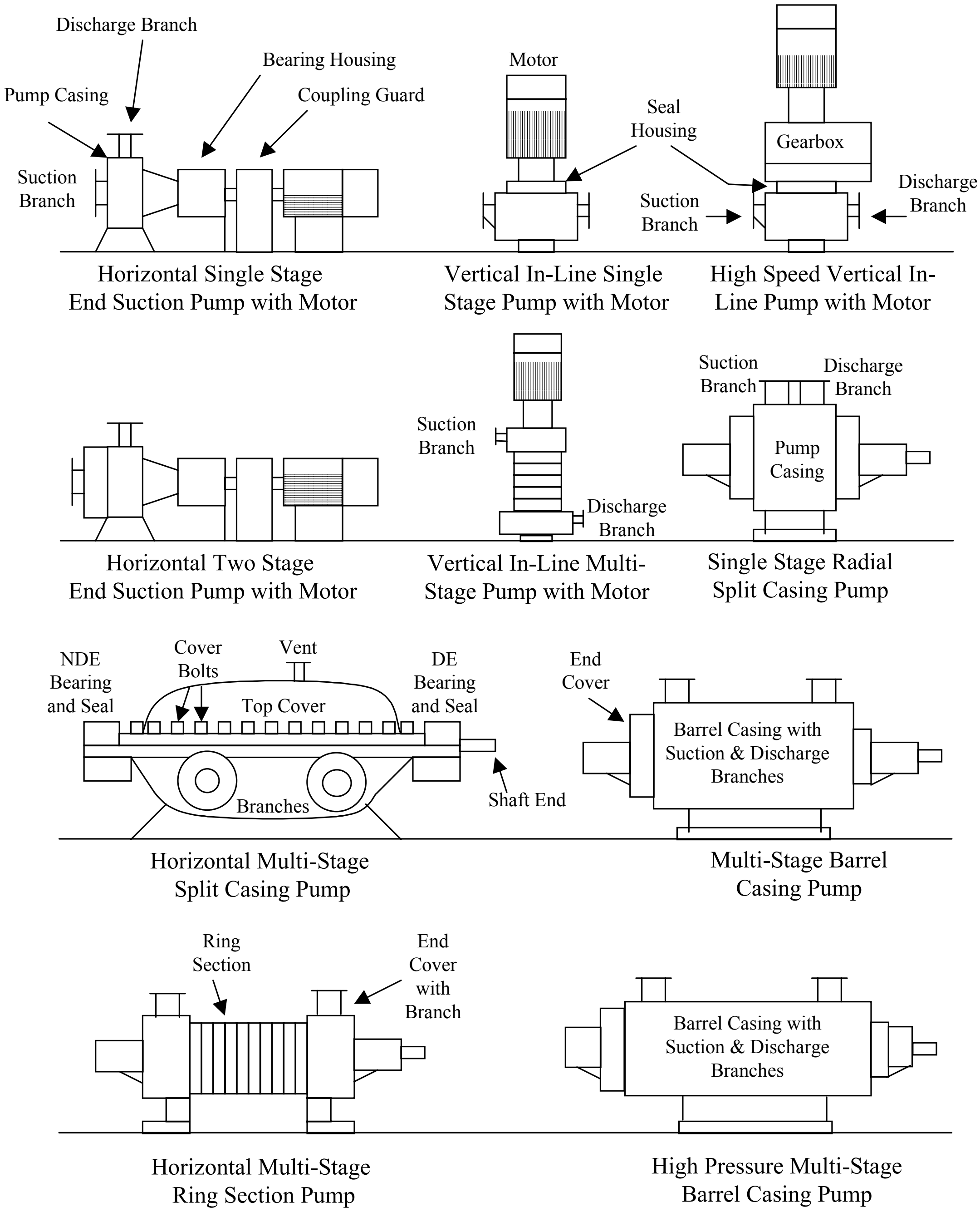
Axial pumps are simply liquid propellers in pipes. Only a single stage is used as the downstream turbulence would greatly reduce the benefit of further stages.

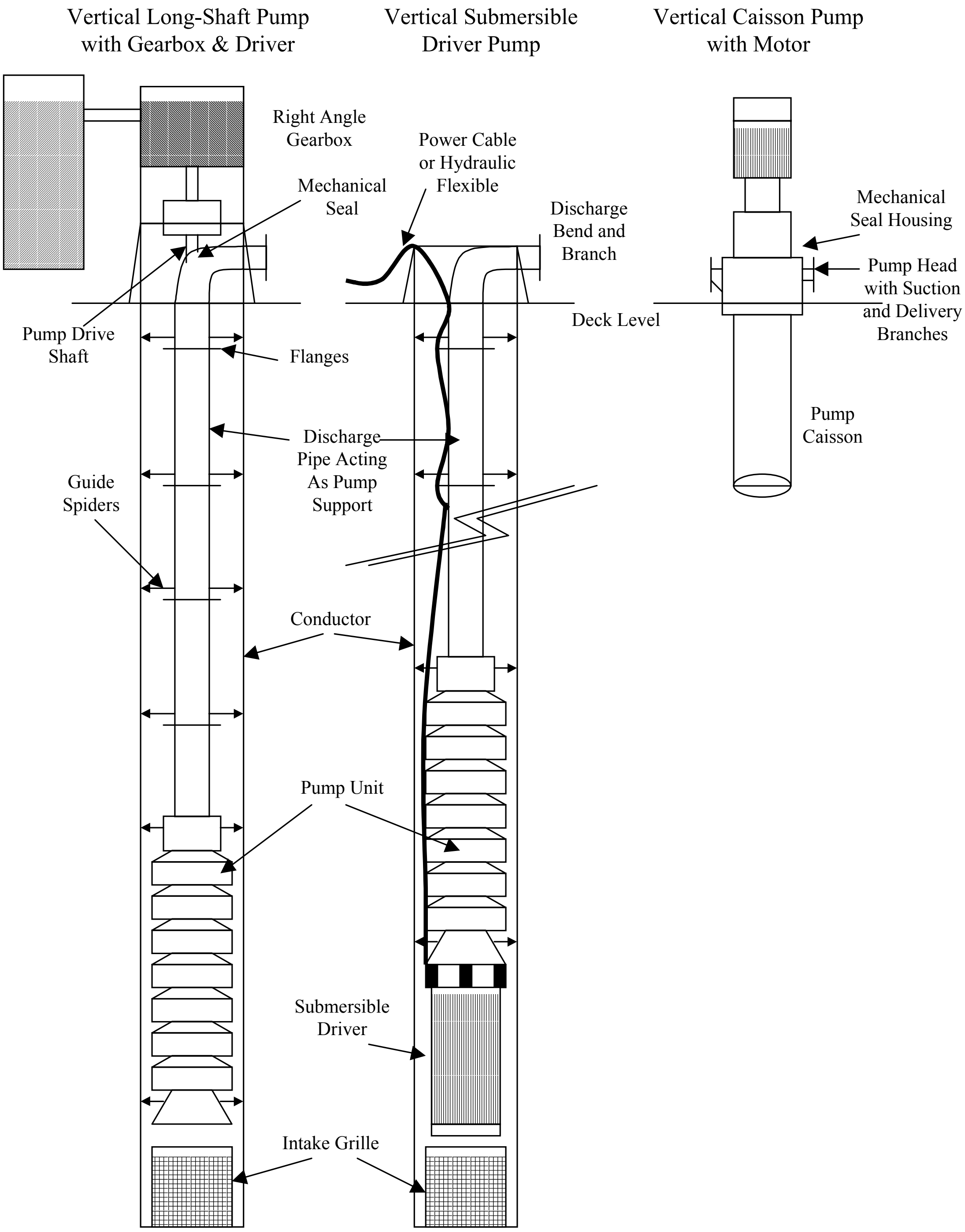
Dynamic pumps have relatively few moving or contacting parts, low vibration levels and thus high intrinsic reliability. Hence they are preferred over other pump types where they can be used effectively. Pump selection needs clear statement of the intended duty and all temporary or transient duties to ensure capability over the complete operating range. Issues may arise if the pump is used for operation on higher density fluids when pressure containment capability can be exceeded when the developed head is translated into fluid pressure – typical situations arise when a hydrocarbon pump is used to pump water which can be 50% denser.

The materials of construction must be able to take the intended mechanical, thermal, and pressure loads and therefore are generally metallic; in addition those parts in contact with the process must be chemically compatible. Non-metallic materials are often used in seals.

CHART 4,6 - 1

Centrifugal Pump Application Chart (with legends)




Vertical Long-Shaft Pump
with Gearbox & Driver
Vertical Submersible
Driver Pump
Vertical Caisson Pump
with Motor
Right Angle
Gearbox
Power Cable
or Hydraulic
Flexible
Mechanical
Seal
Discharge
Bend and
Branch
Mechanical
Seal Housing
Pump Head
with Suction
and Delivery
Branches
Pump Drive
Shaft
Deck Level
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Caisson
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As Pump
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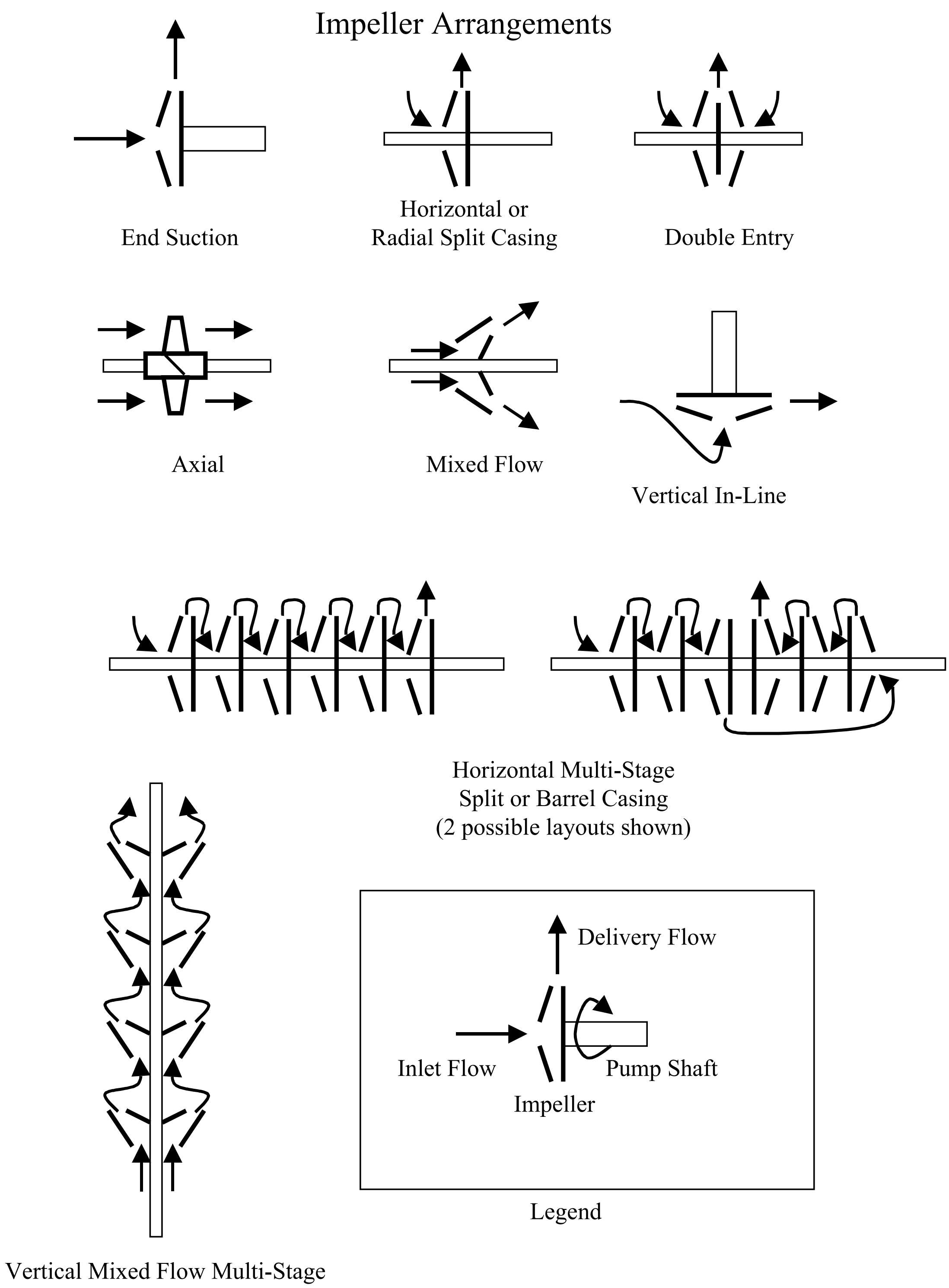
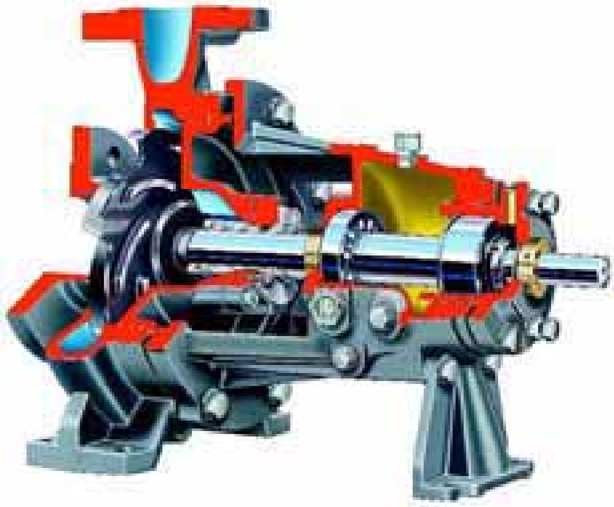
Pump Unit
Submersible
Driver
Intake Grille


Impeller Arrangements
End Suction
Horizontal or
Radial Split Casing
Double Entry
Axial
Mixed Flow
Vertical In-Line
Horizontal Multi-Stage
Split or Barrel Casing
(2 possible layouts shown)
Delivery Flow
Inlet Flow
Pump Shaft
Impeller
Legend
Vertical Mixed Flow Multi-Stage



Centrifugal Pump Types.

Top Left - Canned

Top Right - Mag-drive

Left - Single Stage End Suction with Mechanical Seal

Below - Multistage Horizontal Split to API 610

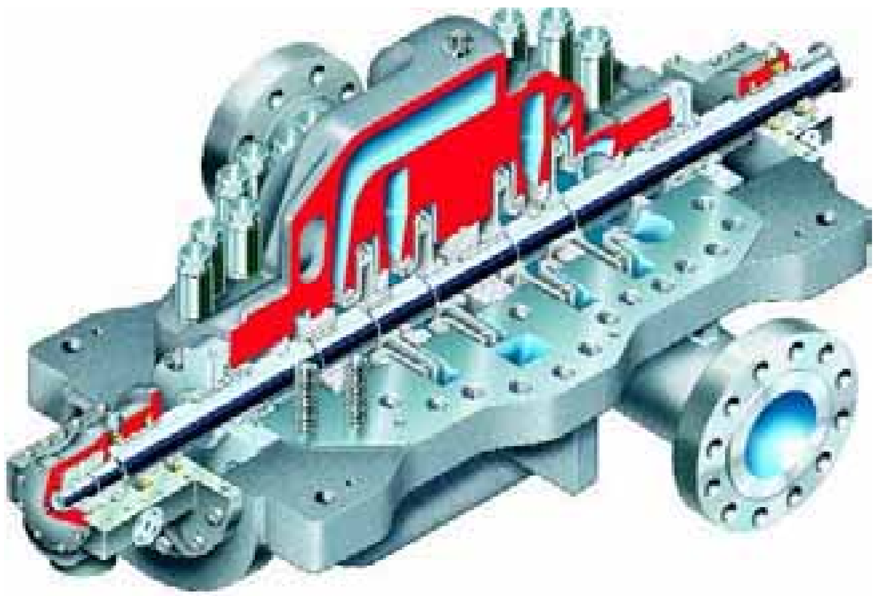
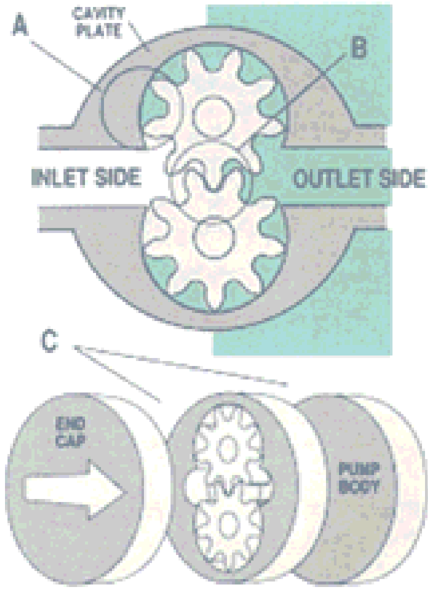


Figure 4,6 – 1 Centrifugal Pumps



Rotary Pump Types.

Above - Gear Pump Picture and Working Principle

Below - Twin Screw Pump (Cutaway). Note 4 mechanical seals.

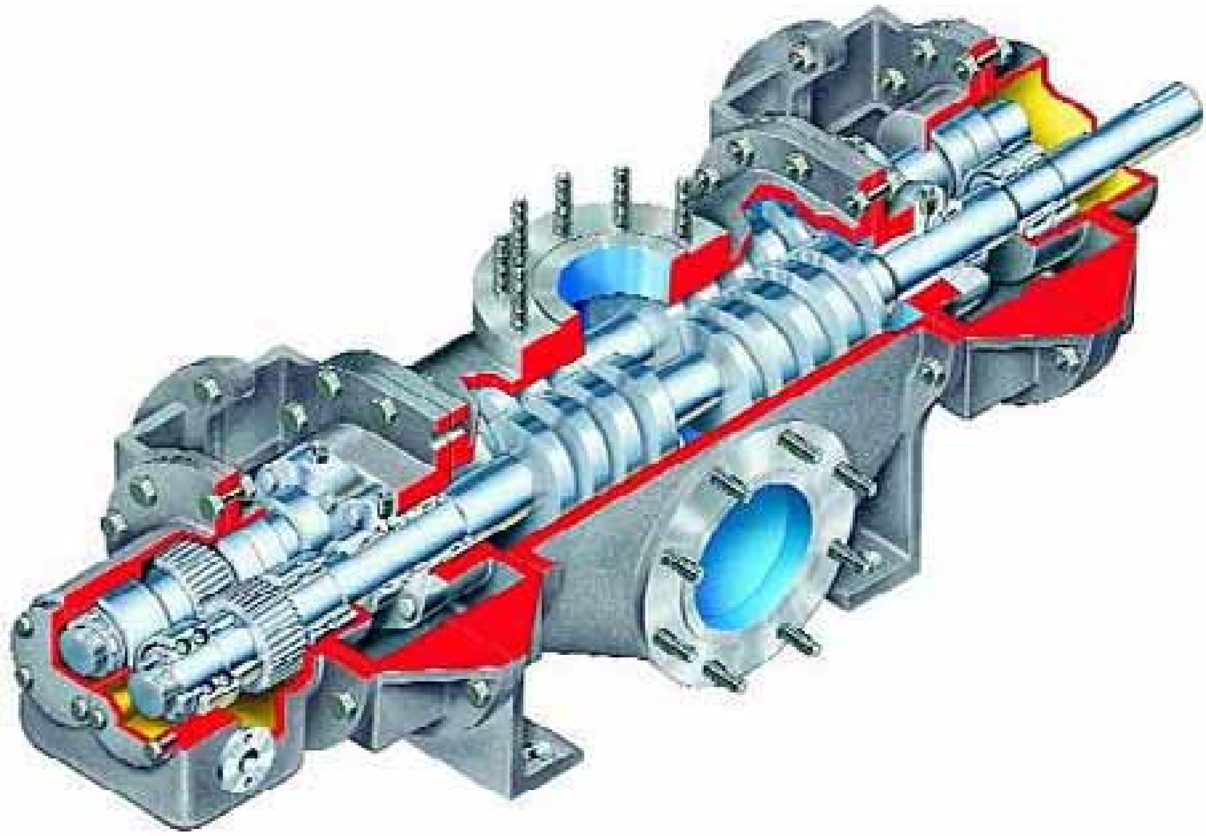


Figure 4,6 – 2 Rotary Pumps

4.6.1.2 Centrifugal Pump Design Options

Single or two stage centrifugal pumps are usually supplied to an international Standard such as API 610 (see references in **Section 5.15**) a typical form is an **End-Suction** design with a radial discharge. Very large pumps have a **Radial Split Casing**, with radial suction and delivery branches. (see **Section 4.7**).

An alternative choice for small or large pumps is the **Axial Split-Casing** design. This is often referred to as the Horizontal Split Casing design, but can also be mounted vertically. These pumps have a casing that is split along the shaft into top and bottom casing "halves" although the bottom casing "half" is physically bigger and carries suction & delivery branches, bearing and seal housings and mounting feet. The top casing "half", though heavy, is simple to lift off as it is basically just a cap. Removal of the top casing allows the rotor to be lifted out complete. The shaft has two mechanical seal systems and two externally mounted bearing housings. Any pump with this bearing arrangement is referred to as a “Between Bearings” design. The pump can be serviced in situ, or smaller units can be removed complete to workshop conditions.

Multistage pumps can be supplied in horizontal split-casing design or (modern preference) **Barrel Casing** design. These pumps have an internal cartridge with (usually) several impellers on a common shaft, all fitted within a pressure casing. This design is treated in detail in **Section 4.8** and **Section 4.10**.

Vertical shaft designs are often used in oil & gas processing installations, either to reduce the installation footprint (compared with horizontal designs) or to fit into a borehole or vertical well. (Ref **Section 4.9** for **Vertical Caisson** pumps and **Section 4.11** for **Vertical Long-Shaft** or **Submersible** pumps)

To achieve reasonably practical shaft alignment and permit thermal expansion, flexible couplings are normally used between driver and driven shafts.

Horizontal shaft pumps require robust baseframes to match the pump to the driving machine, this baseframe needs to carry shaft torques and piping loads without excessive distortion and to provide the necessary stiffness for alignment and dynamic stability. This is particularly true offshore with the baseframe having to be entirely independent of the offshore installation where the structure itself is mobile, due to the influence of waves and weather.

Vertical shaft pumps may be mounted so as to carry pipe and casing loads into the baseframe, the motor is then normally mounted on a stool which is itself mounted on the pump casing. This eliminates the alignment issues related to baseframe design. An alternative arrangement for lift pumps is that they are built as slim vertical cylinders, driven by a long flexible shaft or direct-coupled motor.

The vast majority of pumps are shaft driven by a separate electric motor, or less commonly by a gas turbine or diesel engine. In some cases the performance of the pump requires operation at different speeds to the driving machine, in these cases an intermediate gearbox is used to either step up or step down the speed. {For duties requiring to operate over a range of duties variable speed installation can be chosen using either a mechanical variable speed unit or for electric motor driven pumps a variable frequency drive can be provided}

Pumps in general require at least one process material shaft seal and the associated equipment to service the sealing system. See **Section 5.3** for general details on sealing systems.

The safety of pumps handling hazardous materials is dominated by their shaft sealing systems. These require appropriate design, maintenance and operator attention.

Design options exist which eliminate the requirement for dynamical sealing systems. In "**Magnetic Drive**" End-Suction pumps the mechanical seal is effectively replaced by a sealed magnet assembly. This design ensures nil leakage in normal service, without any external

support services. Other designs integrate driver and pump in an overall pressure casing – normally referred to as "canned motor" pumps.

Canned Motor pumps are similar to a conventional end suction single or multi-stage pump, with the pump shaft, seal and bearings replaced by a special motor rotor running in product lubricated bearings. The motor stator is close-coupled to the rear of the pump casing, separated from the rotor by a thin non-magnetic metal "can". This forms part of the complete pressure containment, eliminating the mechanical seal. This design is particularly appropriate for clean light hydrocarbons, e.g. Gas Condensate, which can be difficult to contain with conventional mechanical seals.

Because the bearings are product lubricated, and both the bearings and the motor are substantially product cooled, this type of pump can be prone to gas locking and rapid bearing failure. This requires special attention to piping system design, gas venting and pump protection. In the event of bearing failure, the thin containment "can" may be ruptured, and the motor stator flooded. It is good canned motor pump design practice to provide secondary pressure containment rated to the full pump design pressure.

Canned motor pumps are available up to about 75 kW and are commonly used in the chemical industry for clean low viscosity fluids and in particular for very hazardous fluids e.g. liquid chlorine. They are not common in the oil & gas industry or offshore.

4.6.1.3 End Suction Process Pumps

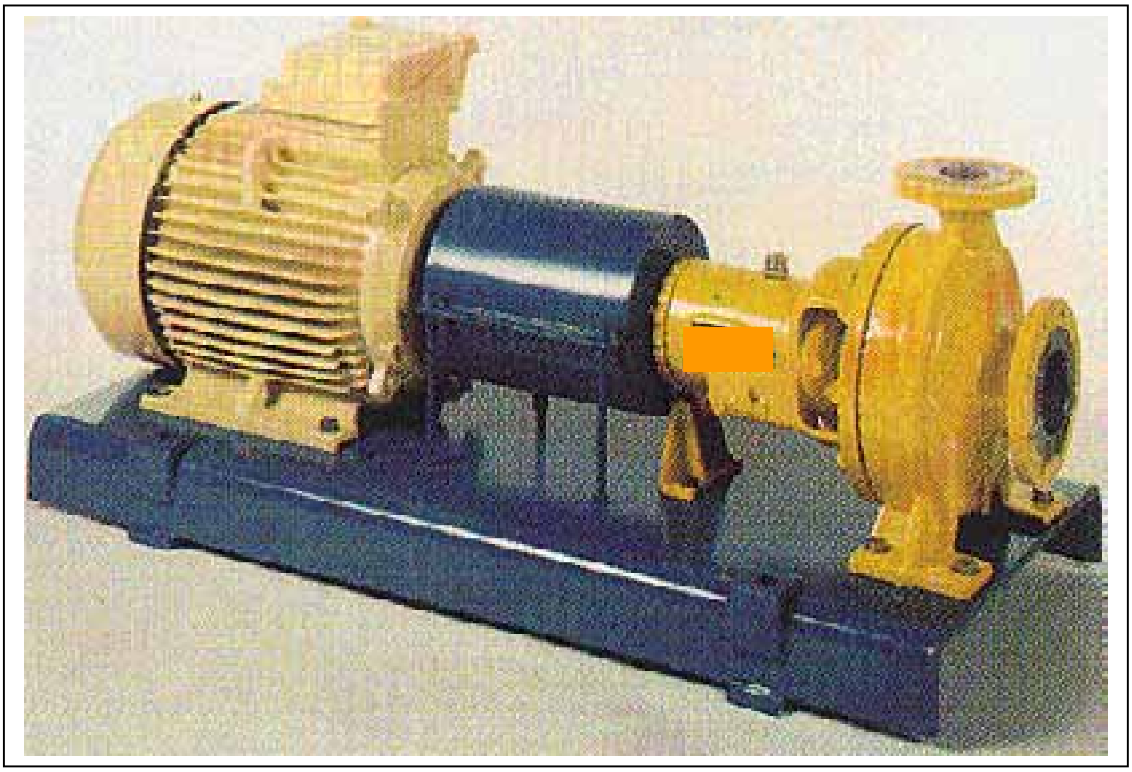


Figure 4,6 – 3 End Suction Process Pump with Motor

Most pumps are of end suction design, these pumps have an axial suction branch and a radial delivery branch cast into a single casing. The rear cover, containing the mechanical shaft seal, is clamped to the rear of the casing, with a static seal formed by a gasket or O-ring. The pump shaft passes through the rear cover and carries the impeller. The pump shaft is supported by a

bearing housing fitted with 2 rolling element bearings. There is a large air gap between the rear of the mechanical seal, and the bearing housing, to prevent process fluid leakage post the seals from compromising the bearing system. The rear end of the shaft is normally fitted with a flexible coupling, linking the pump to the driver.

Modern end suction pumps are designed such that the working parts of the pump may be withdrawn in a single unit for maintenance. This "Back Pull Out" unit is the complete pump, including the seal, less the front casing. Back Pull Out units can be exchanged quickly but it is still necessary to inspect the front casing for damage, and carry out an alignment check, as part of the job.

Two Stage Centrifugal Pumps

Many end-suction pumps are available in 2 stage format, with an extended casing and shaft, a second impeller and an inter-stage spacer.

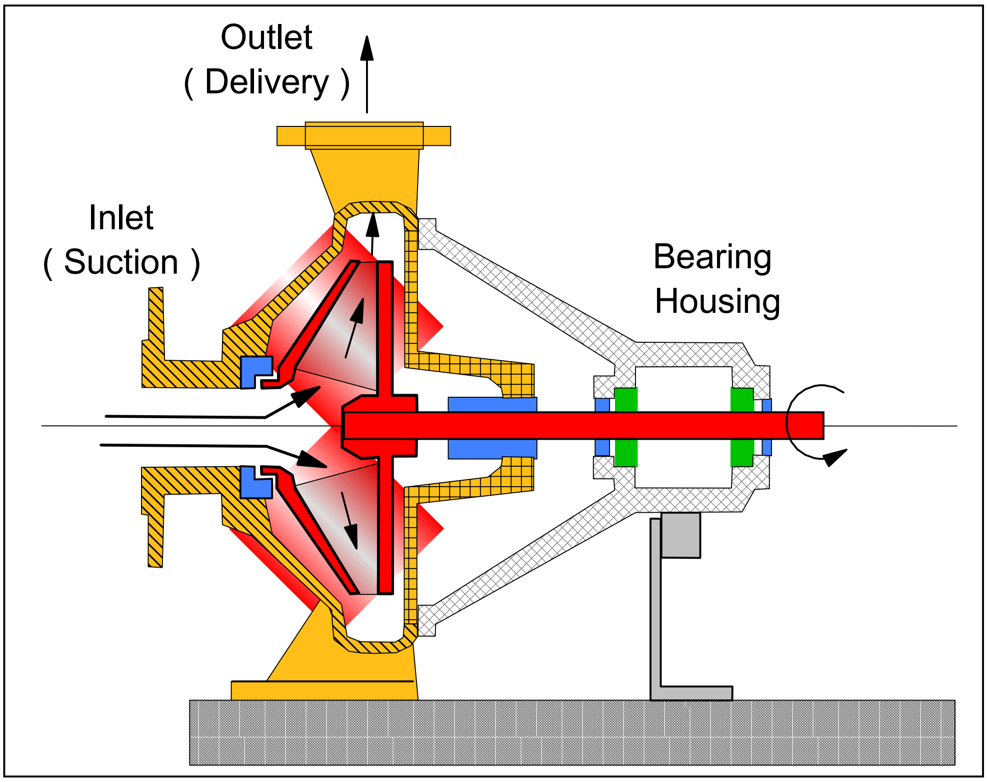


Figure 4,6 – 4 End Suction Pump (working principle)

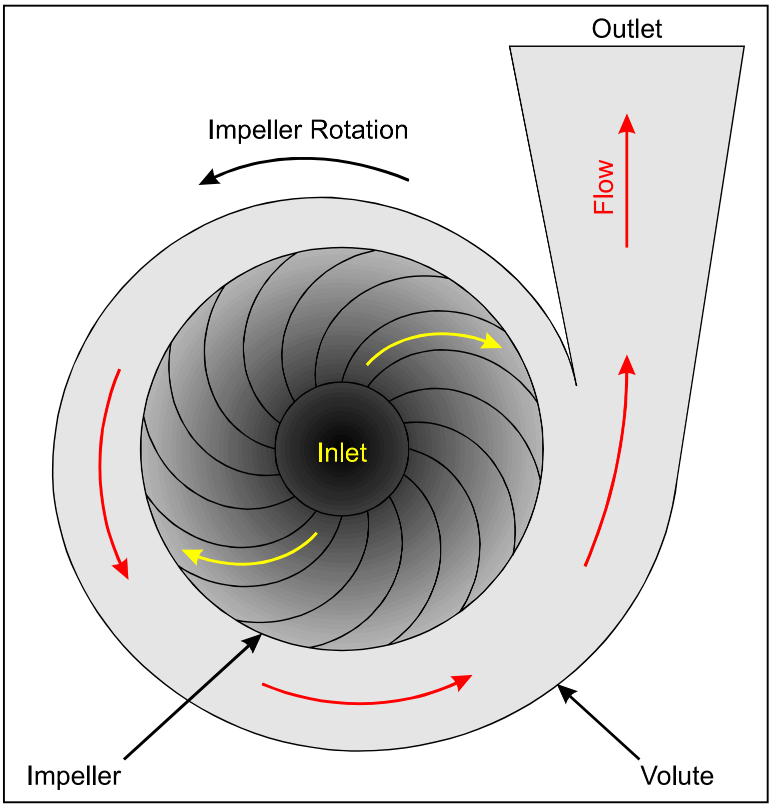


Figure 4,6 – 5 Centrifugal Pump Impeller Flows

Large Single Stage Pumps – design choices

Large single stage pumps, with flows greater than perhaps 500 m3/hour, are not available in end suction design.

There are three practical design choices for Large Hydrocarbon Pumps, any of which may include a double-entry first stage impeller to handle the largest possible flow rate :-

Axial (Horizontal) Split Casing pumps are a traditional solution, being available from single up to about 10 stages. They are normally maintained in situ by lifting off the top casing, removal of the lower casing being a major operation.

Figure 4,6 – 6 Large Axial Split Casing Pump

Barrel Casing pumps are referred to in more detail in **Section 4.8** (standard design) and **Section 4.10** (High Pressure applications)

Radial Split Casing pumps are a hybrid between end suction and barrel casing, they have a simplified barrel casing with suction and delivery flanges. The impeller is contained between bolted front and rear covers. The shaft has two externally mounted bearings and two mechanical seal systems. This type of pump is not a Back Pull Out or cartridge design, so must be maintained in situ. Even the individual components are very large and require significant working space. See **Section 4.7** for a Large Crude Oil Pump of this design.

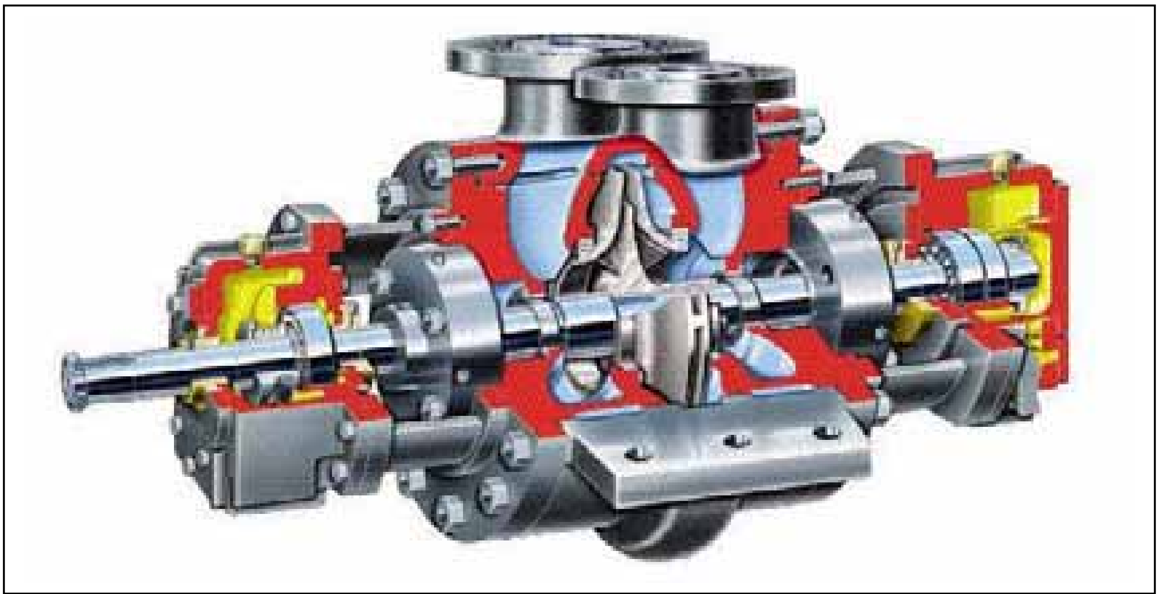


Figure 4,6 – 7 Double Entry Radial Split Casing Pump Cut-away

4.6.2 BACKGROUND & HISTORY

- ***Early centrifugal pumps were of cast / wrought iron with simple packed glands as process material shaft seals.***
- ***Modern pumps are built of carbon or stainless steels with sophisticated process duty mechanical shaft seals and supporting systems.***
- ***Modern cast impellers are designed to give high energy efficiency.***

Centrifugal pumps have been in use for well over a hundred years, early designs being based on cast iron and wrought iron. Early pumps had packed shaft glands, with inevitable leakage. These pumps being the norm up until the 1960's. Since then mechanical seals have taken over, although a large number of pump designs in the 1970's and 1980's were really packed gland pumps converted to mechanical seals, with significant compromises. Fully modern pumps are specifically designed for use with mechanical seals, considerable care is taken to optimise the seal environment.

Seal-less designs utilise either magnetic drives or integral electric motors; this removes the risk of seal leakage.

Single Stage Pumps

Typical modern single stage process pumps have shaft speeds in the range 1500 – 7000 rev/min, shaft power in the range of 0.5 kW to perhaps 20 MW. The design and fabrication of the impellers of all but the cheapest pumps is sophisticated, using state-of-the-art casting, to minimise machining & maximise efficiency. For hydrocarbon pumps the casings are typically of carbon steel, and the stator and rotor parts from carbon steel or cast iron to suit the duty. Trace elements in the range of process fluids expected over the duty life will dictate the exact choice of materials & coatings.

4.6.3 HAZARD ASSESSMENT

- ***The hazards associated with a centrifugal pump have to be considered over its complete operating / maintenance cycle, and not just steady load operations. Mal-operation / excursions / drive system failures and emergencies must all be covered.***

- ***The majority of hazards relate to the process fluid, either by a direct release, or by the consequent effects on upstream & downstream systems from a pump failure.***

- ***Static components can fail through fatigue, erosion or corrosion.***

- ***Dynamic components can fail, leading to high fatigue loads on other components with potentially rapid catastrophic deterioration of seal or nozzles.***

- ***The pipe system can fail due to extreme vibration, pressures or temperatures – either externally applied or generated by the operating pump or system, resulting from events such as pressure surges, process density or composition changes.***

4.6.3.1 Process Substance Containment

The process fluids on oil & gas installations vary from clean water, through highly flammable but clean Natural Gas Liquid, to heavy mixtures like Crude Oil. Hazards relate to releases of process fluids, or to materials left inside equipment which is then opened up. It is assumed that no materials are handled which can detonate or decompose exothermically. These special hazards are not addressed in these Guidance Notes.

Crude oil will also contain contaminants, some toxic such as hydrogen sulphide, radioactive such as strontium salts, or just water or grit. Additives may be introduced which have toxic properties, though these would normally be only in low concentrations.

The direct threats to personnel from a release arise from :-

- The flammable nature of fluid released – volatile components would form a gas cloud with potential for explosion, or fire.
- Operation at high pressure will increase amount of release, may atomise material to form larger vapour cloud, and result in static discharge.
- Physical injury from a jet of fluid, or slips / falls from contaminated floor surfaces.
- Liquids may well be hot, giving a scalding risk above 70 C.
- They may also evolve asphyxiating gases.
- The toxic nature of components or additives within process material. Liquids containing hydrogen sulphides are highly toxic.

- Small traces of radioactive salts within the process material can accumulate within a pump requiring appropriate handling precautions.
- Inappropriate operation of the pump can induce high temperatures and pressures within a pump, giving rise to hazards from mechanical disintegration of the pump.
- Handling material with higher concentrations of water or solids can lead to higher pressure generation due to the effective increase in density.
- Corrosive materials e.g. Acids and Alkalis will be handled in small quantities.

Hydrocarbon liquids pose a real safety threat if released in quantity / concentration sufficient to permit a fire / explosion. Designs with the least number of joints and connections are much preferred, and may form part of the safety case for the whole installation. All possible joints should be welded. Even small bore joints should be welded or flanged, not screwed. This should also include systems used for draining the equipment in a non-operating condition.
All process pipework within the main isolation valves should be treated as part of the machine system, particularly as part of it may well be supplied with the package. Small-bore pipework is weaker than large bore, thus more vulnerable to damage. It can be a great hazard though holding a smaller inventory. It is good practice to have robust primary isolation valves, at minimum 1" (25 mm) or 1 1/2" (40 mm) size, where small bore harnesses connect to main pipework. A failure can then be isolated quickly.

In the event of a major release it will not be possible to get near to the machine to close the isolation valves. Thus strategically located emergency shut down valves are installed, to prevent escape from the rest of the system. Such isolation valves should permit closure from the control room, but should also close if their energising supply fails or sustains damage. The closure times of the isolation valves should consider both the requirements for effective isolation and the effects of pressure surge. Control valves should not be used as isolation valves because they do not close sufficiently tightly. Operation of isolation valves will also require to be linked to machine stops to avoid subsequent hazards from the pump. Operation of a pump with closed isolation valves can result in a rapid pressure and temperature rise, sufficient in extreme cases to rupture mechanical seals or the pump casing.

It must not be possible to bypass or disable the main remote isolation valves, except as a planned activity, for example as part of commissioning or testing on low hazard fluid. It is assumed that all non-routine activities will be managed under a robust Permit To Work (PTW) system. No modification that bypasses the isolation valves should be accepted, without a clear understanding of the necessity of this arrangement, and a formal and thorough assessment of the associated risks, in accordance with company procedures. There should be a drain/ purge system, usually to closed drains, for cleaning out and decontaminating the pump system. The system may hold a significant quantity of liquid in casings and pipework, up to the isolation valves. It is important to know if parts of the system cannot effectively be drained.

While pumps can tolerate a small amount of free vapour, reducing the generated head, ingestion of large quantities of vapour can cause pressure swings or cause the pump to lose its prime and stop pumping. Vapour should normally be removed in a suction separator, which provides a suitable inlet static head and minimises bubble entrainment. Centrifugal pumps can tolerate non-abrasive solids (e.g. wax) provided that these do not block small seal passages. Due to the potential for lower temperature of the casing extremities, seal flushing lines or passages can be provided with trace heating to bring these areas up to process temperature prior to start-up. This heat melts any wax deposits. Abrasive solids can cause damage to seals and labyrinths, affecting pump performance and promoting seal leakage. An increase of the density of the pumped fluid, due to the addition of solids or a higher density fluid e.g. water, will cause an equivalent increase in the pump discharge pressure and hence the power consumed.

Internal corrosion can occur, unless the wrong materials have been used is not usually anything like severe enough to cause major damage. A special case is stress corrosion cracking caused by operation with fluids containing for example Hydrogen Sulphide or, under certain circumstances, Chloride Salts. The failure mode in this case is in general progressive, but requires vigilance for porosity both during operational and maintenance inspections

Similarly operation with unexpected sand or drilling mud content can cause internal erosion. This is likely to give a warning by dramatic loss of pump performance. Erosion tends to lead to casing perforation rather than rupture.

Mechanical Seals

The mechanical seals on hydrocarbon pumps are typically of double back-to-back design, using a pressurised seal fluid. This gives the benefit of nil leakage of process fluid to atmosphere, warning of failure of one seal element, and independence from the properties of the process fluid.

The limitation of double seals is their complexity and dependence on high quality fitting practice. Even in the event of complete seal failure, the internal clearances are small enough that the release rate is not huge, unless the shaft has been bent or displaced.

Less hazardous fluids can be contained using simpler single seals, ideally with some form of secondary seal to minimise the release rate on seal failure. Close fitting throttle bushes give robust and predictable protection. Lip seals or similar can give very tight secondary sealing but are not guaranteed to be operational. In-service testing of secondary seals is difficult.

Leakage from seals is a sign of failure, seals do not bed in or recover. It is important is that a pump with a failing seal is not run longer than is absolutely necessary for safe shutdown or duty change-over.

For details of Bearings, Seals, Shaft Couplings and related hazards see **Section 5 – Auxiliary Systems & Equipment.**

4.6.3.2 Equipment Hazards

Single Stage Process Pumps

The basic concept of a single stage centrifugal pump is extremely simple; there is only really one moving part.

MECHANICAL HAZARDS FROM PUMPS

- ***Dynamic stability – vibration leading to bearing and machine component damage.***
- ***Process induced vibration – running at BEP?***
- ***Overspeed and reverse rotation – mechanically or process induced.***
- ***Bearing failure / lubrication.***
- ***Loss of restraint for machine components such as couplings***
- ***Failure of connections – overload and fatigue issues.***
- ***Noise***
- ***Entrapment from contact with the rotating shaft***

The internal design of pumps normally balances out most of the axial forces on the impeller, leaving the residual force to be taken by the thrust bearing. Faulty design, internal wear or damage, or running outside the design duty range, can put excessive loads on the thrust bearing. This can lead to premature bearing failure.

Running a pump at any flow other than Best Efficiency Point (BEP) puts additional loads on the bearings, these are allowed for in the pump design. Running at very low flows (perhaps because of a blocked recycle line) not only increases bearing loads but also results in highly turbulent flows within the impeller passages. The resultant vibration can damage seals and bearings, and even cause fatigue damage to pipe connections.

Pumps driven by fixed speed drivers e.g. asynchronous A.C. motors, cannot run at a forward speed higher than the nominal drive speed. Pumps driven by variable speed drivers will be protected from forward overspeed by the governor and protective device(s) on the driver. Incorrect electrical connections will cause a motor driven pump to run backwards at full speed. On an initial start of the pump, or after change out for overhaul refurbishment, it is good practice to check the electrical phase connections for correct rotation, and, if at all possible, to run the motor uncoupled to check the direction of rotation and speed. Reverse rotation will not necessarily be evident, as the pump will still deliver a reasonable flow. Many bearing and seal systems, in particular some gas seal designs, cannot survive reverse running at any speed. Some pump impellers are screwed onto the shaft end and will unscrew if started in reverse, seizing the pump. Re-starting the pump in a forward direction and screwing the impeller violently back on could well break the shaft.

Pump systems normally rely on Non-Return Valves (NRV's) to prevent fluid from flowing from the high pressure discharge system back through the pump when the latter is stopped. This is particularly significant if several pumps run in parallel, or if the liquid is being discharged below a reservoir of pressurised gas. If the NRV fails to close, reverse flow will occur when the pump stops. This will drive the pump and driver backwards at speed, unless the drive is fitted with a brake. This reverse rotation can do serious internal damage to the pump and the driver, but should not be fast enough to rupture the impeller unless there is a high gas pressure in the discharge pipework. Gas breakthrough can potentially give very high speeds with potential rupture. Failure of the drive coupling can give higher overspeeds, as there is less drag. Overspeed protective devices on the driver are ineffective when it is being driven backwards by the pump.

Bearing failure, perhaps from loss of lubrication, can damage the seal and cause leakage. In extreme cases a failed bearing can cause the shaft to overheat and shear, inevitably causing major damage to the pump and probably a large release.

There should be no mechanical contact between static and rotating parts in a centrifugal pump. However, as some clearances can be less than 0.5 mm, there is the potential for contact if there is bearing failure, pump damage, debris enters the pump, or thermal shock which bends the shaft, causing contact. There may be no direct hazard, although this can cause high vibration levels, seal damage and the motor and drive coupling and bearings of the pump to be overloaded. The steel wear debris can also cause problems downstream.

Failure of the mechanical seal(s), or of any of the static seals, can cause a release. Good pump design, e.g. fully contained static seals, reduces the risk both of seal damage and of significant consequential release. (See **Section 4.6.3.1**)

Good installation standards for pumps are important to both reliability and safety. Alignment of the drive system to the driven pump needs to be achieved within close limits. Operation of poorly aligned equipment can result in bearing damage, high vibration levels, and to coupling failure.

In some cases coupling failure can result in loss of restraint of the coupling as well as severe disruption to the pump shaft and seal system.

Simple overload of pipe fittings through thermal effects, high vibration levels or bad installation may lead to failure of pipe connections or fittings. Given the ductile nature of carbon and stainless steels, this is most likely to show as a weeping joint or cracked weld. Severe vibration, whether from hydraulic or mechanical problems, can lead to complete failure. The most vulnerable items are overhung vent and drain pipes fitted with relatively massive valves or blank flanges. Poorly welded bracing brackets can make matters worse by providing a stress raiser.

4.6.3.3 Operational / Consequential Hazards

Pumps are designed to operate at an optimum flow rate, at which hydraulic loads are minimised and efficiency is maximised. Below a minimum flow rate specified by the manufacturer, (typically 25 % of optimum) the hydraulic loads exceed the pump design, flow instabilities occur, and overheating can occur if there is not enough flow to carry away the input energy.

It is normal practice to start pumps fully primed, suction valve open but with the discharge valve closed. This takes minimum power, letting the drive run up to speed quickly. The discharge valve should then be opened slowly, to avoid pressure surges. Delayed opening of the discharge valve will heat the fluid, potentially to boiling, but pressure will be vented back through the suction valve.

No pump should ever be throttled by the suction valve, as this is likely to create cavitation and damage the pump. Cavitation is the formation and collapse of vapour bubbles within the pump, due to an initial decrease in the pressure of the fluid as it is induced into the pump. This process

also causes micro cracks on vulnerable components such as the pump impeller. Severe cases result in loss of performance due to internal pump damage.

While it is possible to throttle on the discharge valve, on a large or high head pump this is likely to damage the valve over time, and tight closure will then not be possible. Starting a pump with the delivery valve wide open takes the maximum amount of power and may overload an electric motor driver. In addition, if the pump is delivering into empty pipework with a closed valve at the far end, “surge pressure” effects can produce a shock wave, potentially doubling the discharge pressure, damaging instruments and displacing equipment.

An abrupt loss of the steady operation of the pump may cause disruption of the upstream or downstream systems. This may result in systems being shut down, or load being transferred on to other pumps. The pump stop will cause “surge pressure” effects and a “negative” pressure wave. This can cause water hammer, particularly in long pipelines. The safety studies (e.g. as carried out as part of the safety case) must ensure that there are no circumstances where a pump fault might cause an unsafe condition e.g. over-pressurisation of the discharge header.

It is common practice to run pumps in parallel to meet a required duty. It is normally necessary that the pumps doing this have identical internals, to avoid poor load sharing and possible hydraulic vibration, instability or overheating.

Flow can be controlled by a combination of on / off control, downstream control valves, and variable speed control. Variable speed control of parallel pumps requires a sophisticated system to match pump loads.

Operational practices to identify and avoid these issues are covered in **Section 6**.

4.6.3.4 Maintenance / Access Hazards

Single and two stage pumps, even of high capacity, are physically small machines and can often be hidden by surrounding pipework, equipment and structures. Pumps are not usually lagged or surrounded by acoustic enclosures. Installation & Alignment have to be done in situ, but if possible all other jobs are better done in workshop conditions. Hence access is required to permit removal of the Back Pull Out Unit / cartridge, and substitution of an overhauled and leak tested replacement.

Multi-stage pumps may, according to the design, have a removable cartridge. Otherwise, at best, only the complete rotor can be removed to workshop facilities.

Pump designs which can only be maintained in situ require good all-round access, and somewhere to lay down the removed parts (not necessarily immediately next to the machine, and not in a defined escape route or major walkway). Lighting can be brought in for the purpose but lifting beams are much more suitable for extended in-situ lifting work than platform cranes which are too big, too remote and probably in demand for other activities. If the installation is subject to wave motion, safe lifting may be impossible in bad weather.

Pumps are normally safe and straightforward to lift and handle, with suitable precautions and due care to catch or contain any hazardous fluids they may contain. The exception are magnetic drive pumps which are very much heavier than they appear, containing powerful magnets which can chop off fingers if carelessly handled. Special tools and training are required for working on these machines. They are also not tolerant to being dropped.

4.6.4 OPERATING REQUIREMENTS

- ***Centrifugal Pumps specified to API codes are designed for long periods of continuous operation, e.g. 3 years or more.***

- ***Over-rapid starts, stops or duty changes can cause pressure surges and consequent damage remote from the pump. The longer the pipeline, the gentler the operation which is required due to the delayed response.***

4.6.4.1 Continuous Unspared Operation

It is perfectly normal for pumps built to API 610 to be capable of continuous operation for 3 years or even longer, the limitation being normally the mechanical seal, which is prone to random (hence unpredictable) failure. Good pump & seal selection, proper installation, condition monitoring & smooth operation all contribute to high reliability. If duties are known to have poor reliability, this is an indication that some feature of the installation or operation is at fault. Fitting a new pump, even of a different design, is not guaranteed to solve the problem.

4.6.4.2 Continuous Spared Operation

One running pump with a spare might appear to be the better option, but can be less reliable than unspared operation, simply because there are more components to go wrong. In fouling duties the "spare" pump can often block or seize and be unusable within a short period of standing by. If truly high reliability (98 % +) is required then 2 continuous 100 % duty machines, both running, are required. Or 3 x 50 % machines, etc., This requires appropriate recycle and turn down systems.

4.6.4.3 Emergency Duty

Pumps on emergency duty are normally left primed with clean liquid, ready for automatic start. Delivery will be isolated by self-opening valve (i.e. Non Return Valve) or by remote operated valve, linked to the starter. The installation will be as simple as possible. The system (or its components) should be tested periodically, but in such a way as to avoid corrosion / contamination.

4.6.5 MAINTENANCE REQUIREMENTS

- ***End suction single stage pumps are designed to be maintained by removal of the Back Pull Out Unit to a workshop, there is seldom the access or suitable conditions for in-situ work.***

- ***Some very large pumps which can only be maintained in situ require good all round access and lifting facilities.***

- ***Residual hazards will be present from trapped liquid / radioactive salt deposition***

It is assumed that Back Pull Out Units will be removed to a workshop for any maintenance. The only site work thus required is inspection of the condition of the front casing, including the measurement of neck ring clearances. Provided there is adequate access, refitting the Back Pull Out Unit is straightforward. Shaft alignment cannot be assumed, however, and laser alignment equipment should be used. If pipework has been disturbed, the alignment should be checked before and after re-bolting the suction and delivery flanges. This is the only way of demonstrating that the pipework loading is not distorting the pump.

End suction single stage pumps can be inspected and maintained in normal workshop conditions, although larger units may stretch the available space. Seals and bearings require clean and well lit areas, skilled personnel and the right tools. Damage to these components may not be visible but contributes to early failures.

It is important on rebuild that seal support systems and instruments are also put back in working order, filled with fluids as required, and the correct valves opened / closed.

Larger Centrifugal Pumps

If the pump is too large to have a removable cartridge, the bearings, seals and rotor can be removed to workshop for inspection / overhaul, but a high proportion of the work will be done in situ. Hence working conditions / lighting / lifting facilities / laydown space / storage of loose parts must be considered. Maintenance procedures must address issues like match marking, component identification. Note that it is not good practice to exchange parts between assemblies as tolerance and wear effects tend to be additive, resulting in poor build. Also rotating assemblies tend to be factory balanced complete; swapping parts around can destroy shaft balance.

The large size and weight of components increases the risk of injuries / damage during handing, especially if access is difficult and lifting facilities are not ideal.

4.6.5.1 Internal Corrosion

Pumps are not normally designed with an internal corrosion allowance, as loss of material creates significant changes in characteristics. Materials should be therefore be selected for corrosion resistance to process fluids, as well as the necessary mechanical strength. For guidance see NACE (National Association of Corrosion Engineers) standards. Corrosion in service is thus only likely if unpredicted trace elements attack the internals; it is not normal practice to open up pumps purely to look for corrosion. It would be good practice to check for internal corrosion if a pump is opened up for another reason. Pipework and fabricated i.e. welded casing pumps can be more prone to corrosion, in particular at the welds.

Most hydrocarbon services exclude oxygen, preventing corrosion in service. However, if equipment is opened up and left exposed to salt-laden atmosphere, rapid corrosion can occur.

Hydrogen sulphide can cause stress corrosion cracking, again normally on fabricated items. If H2S is known to be present, materials design checks and periodic inspection of vulnerable items will be required.

Pumps for corrosive services will normally be made of corrosion-resistant materials, well able to resist atmospheric corrosion during maintenance. Plastic lined pumps are very corrosion resistant until the lining is damaged. After that, corrosion can be rapid and local casing failures occur.

If acid washing / pickling is used to clean metal surfaces, then it is important that surfaces are properly passivated afterwards.

4.6.6 SINGLE OR TWO STAGE CENTRIFUGAL PUMP MAIN COMPONENTS

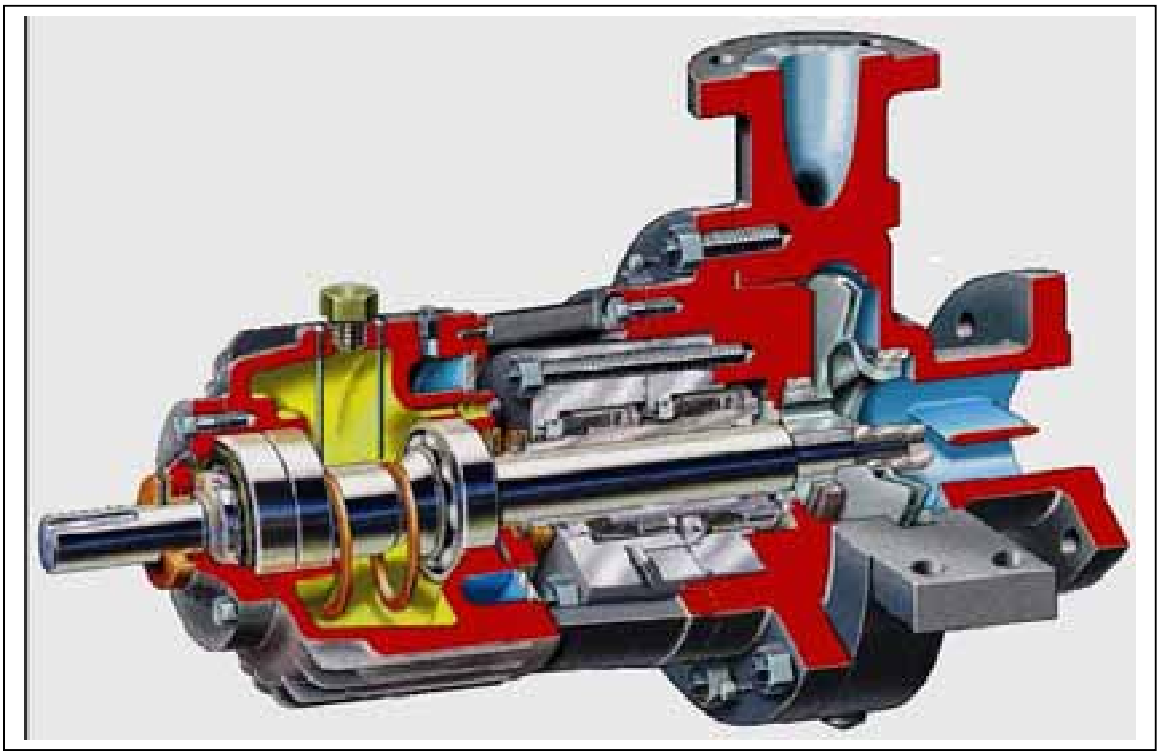


Figure 4,6 – 8 API 610 End Suction Pump Cut-away

4.6.6.1 Front Casing / Bottom Casing

This is normally a single piece casting with flanged suction and delivery branches. Cast carbon steel is the norm for hydrocarbon service although stainless steels and exotic materials may be required for aggressive duties. Casings may be welded into pipework although this makes maintenance difficult – welding may also lead to casing distortion and subsequent un-reliability due to distortion of pump or joint faces. Castings can be porous and should be adequately pressure tested before use to detect leaks.

4.6.6.2 Rear Casing / Top Casing

The Rear Casing of end suction pumps serves as the rear fluid containment and also as the mechanical attachment between front casing, bearing housing and seals. It is normally of the same material as the casing. The pump should be ordered with unnecessary holes left undrilled, as drilled then plugged holes are potential leak points. Screwed in plugs can weep along the screw thread, or even blow out due to thread corrosion. If plugs are inevitable, they should be of matching material, to permit seal welding.

The Top Casing of a horizontal split casing pump forms the upper half of the pressure containment and contains half of each diffuser ring. The joint between the casing halves is via a heavy flanged joint with closely spaced studs/ nuts. The flat joint faces are vulnerable to handling damage and should be protected, once opened.

The bolts or studs and nuts retaining the rear or top casing are an integral part of the pressure containment. Only fasteners supplied or approved by the manufacturer may be used. Typically

these will be of high tensile material, with rolled screw threads. Removal and replacement of fasteners requires care to avoid damage. Fasteners may be of different lengths and it is good practice to match mark fasteners. Tightening must be by progressive and ordered sequence, normally as defined by the manufacturer. Tightness may be judged by torque, measured stretch or measured tension.

4.6.6.3 Impeller

In an end-suction pump, the impeller is fitted to the end of the shaft, usually a parallel fit with key & retaining bolt or nut, but screwed-on impellers are used, particularly for slurry or aggressive duties. Pumps with screwed impellers must never be started in reverse, even for rotation checking, as the impeller can then unscrew and jam. In some designs the seal is also retained by the impeller fastening on to the shaft, in these cases impeller looseness also threatens seal integrity.

The impeller has close clearance fits to front and rear casings and these fits are part of the hydraulic balance of the pump, reducing axial thrust. Grossly excessive clearances can cause rapid thrust bearing wear. There will be static seals between the impeller and shaft / shaft sleeve. Failure of these seals can result in weeping leakage under the shaft sleeve and thus under the mechanical seal. The rate will be very low, but the source will be difficult to locate. It is normal practice to machine down the outside diameter of the impeller to alter the pump characteristics. Fitting a full size impeller by mistake can result in excessive delivery pressures and overload the driver.

For larger, between-bearings type pumps, the impeller is usually a keyed parallel fit to the shaft, retained on both sides by screwed rings, possibly with spacer sleeves. The screwed rings permit fine adjustment of the impeller vs. the diffuser slots. An axial error of > 1 mm can affect the efficiency of the pump. Large pumps often have double inlet impellers (effectively 2 impellers moulded back-to-back), these effectively double the suction capacity of the pump, and also eliminate axial thrust on the shaft.

4.6.6.4 Mechanical Seals

For end suction pumps, one off, normally double, shaft seal is required. Cartridge design is normally preferred. The seal is hydraulically balanced to a pressure somewhat above suction. For "between bearings" pumps, e.g. radial split casing, axial split casing, two sets of seals are required. For double seals, independent seal support harnesses / seal pots are required. For axial split casing pumps, the interface between the horizontal casing joint and the seal cartridge is complex and can be a leak point.

4.6.6.5 Bearings

End suction pumps are quite straightforward, a stiff cast housing contains 2 radial bearings and one thrust bearing (or one combined radial / thrust bearing). Standard pumps use splash lubricated rolling element bearings. The quality of the oil actually getting to the bearings is vital, and any contamination by water, salt, light hydrocarbons or dirt can seriously reduce bearing capability.

"Between bearings" pumps have two bearing housings, one located outboard of each mechanical seal. It is normal for each bearing to be a self-contained rolling element bearing with oil reservoir. One bearing housing (normally NDE) contains a thrust bearing, the other has axial float. Loss of axial float may lead to bearing failures, particularly with hot duties.

4.6.6.6 Support Systems

See also Section 5.0 Ancillary Systems & Equipment.

Pump Baseframe

This will normally be common with the baseframe under the driver (and gearbox if fitted). Small vertical pumps have a simple support base or pedestal, and will form part of the pipework in a module.

Lubrication System

Larger pumps may have pumped lubrication / seal oil systems. The system provides filtration, cooling, monitoring of temperature / pressure. Due to the risk of cross-contamination and for issues of reliability, it is not normal to have common systems serving several pumps.

Seal Support System

The traditional liquid based support system is a pressure pot with thermosyphon cooling, containing a compatible clean fluid (e.g. light hydrocarbon oil). However thermosyphons often do not work as anticipated, and internal pumping rings or external seal circulation pumps may be required. Each seal should have its own support / monitoring system with common services.

Some modern machines have dry gas seals, with the advantage that the support system is simpler and lighter than a liquid support system. A supply of barrier gas is required.

Pump Recycle System

A recycle system is often required for pump venting / priming & to ensure a minimum flow during low output operation. This flow must be returned to the suction system, if at all possible to a vented vessel or vapour space, to remove gas. If the recycle flow can be returned to a large storage reservoir, heat input by the pump will be dissipated. Otherwise it may be necessary to install recycle flow coolers. Return of recycle flow directly to pump suction is likely to cause problems with gas locking of the impeller and seal. If pumps are fitted with individual recycle systems, it is possible to prime and run up a standby pump offline.

4.6.6.7 Control & Management Systems. See also Appendix 2.

The control requirements will be dictated by the function that the pump serves, and by the choice of fixed or variable speed drive. Fixed speed drive would be normal for steady load duties, and for constant back pressure systems. In these cases a delivery control valve is standard, controlling on pressure or flow.

For variable back pressure duties e.g. a long pipeline, variable speed is a viable option as it eliminates large control valves and possible pressure fluctuations.

Depending on the complexity of the system, and the duty requirements, the control system may be required to stop / start pumps according to load, adjust speed, or adjust control valves to match duty requirements.

4.6.7 INTEGRATION ASPECTS

4.6.7.1 Process Duties

Pumps are selected for a chosen duty and any changes in fluid, pressure or flow may take the pump outside its operating envelope. Hence significant process changes need to be reviewed against all the equipment capacities. Pumps require adequate Net Positive Suction Head (NPSH – See Appendix 1), and if the properties of the fluid have been mis-understood or changed, then NPSH may not be adequate and the pump will not work. This is not normally a safety issue, unless lack of operation compromises safety.

Once flow has been established, a small, evenly distributed, gas load can be tolerated, the vendor can advise by how much this will de-rate the pump.

Flow cooling is not normally required on pumps as the temperature rise per stage is typically 1 – 4 C. Higher temperature rises indicate very poor efficiency.

4.6.7.2 Mechanical Integrity

Single stage end suction pumps normally have only 1 main casing joint. On modern pumps this is secured by a full complement of high strength setscrews or studs/nuts. The casing gasket should be fully contained in a recess or spigot in the flange face. The casing to bearing housing link is formed by a cast "lantern" or stool, which has access ports for seal fitting / maintenance. It is extremely unlikely that the shaft could break in such a way as to pull out of the seal housing. It has been known for pumps with cast iron casings to fail by the impeller grinding its way through the front casing. The hydraulic design of a pump is often set up to cause the impeller to thrust towards the suction. Failure of the thrust bearing or of the impeller retaining screw can permit the impeller to bear on the casing. This catastrophic casing failure is very unlikely with cast steel/ stainless steel pumps fitted with impeller neck rings, as the rings can act as crude thrust bearings.

Large "between-bearings" pumps have more casing joints and more complex casing joint arrangements. This is a function of the sheer size of these machines. The breaking, cleaning and re-making of these joints requires care and patience to ensure a full seal. Proper sequential tightening, or the use of hydraulic tensioning, is vital on these joints.

4.6.7.3 Alignment / Balancing

Manufacturer's Responsibilities

Internal alignment and mechanical balancing are part of the quality of the original build. Casing / bearing alignment is by spigots.

Operator's Responsibilities

If the rotor is dismantled or modified in any way, it should be re-balanced, a task requiring factory conditions and machinery. The shaft coupling should be laser-aligned to the best possible tolerance to minimise bearing loads, even if the vendor specifies an inferior method. The future costs of poor alignment can be enormous. The pipework should be designed to keep imposed loads within the API specified limits, often requiring the use of spring hangers, and should be installed correctly. Normally pipework is installed "No-load" when cold, but it may be necessary install the pipework with a designed cold offset, this counteracts the anticipated thermal expansion or contraction. Pumps designed for hot fluids have mountings that support the pump close to its shaft centre-line, this design minimises the effect of pump thermal expansion on the lateral alignment of the shaft coupling.

End-suction pump casing axial expansion should be small and is dealt with by intentional flexibility in the pump rear foot. The flexible coupling should have axial float if the driver has a thrust bearing, and a fixed length or high axial stiffness if the driver has no thrust bearing.

"Between-bearings" pumps have significant casing and shaft expansion when on hot duties. The casing is effectively centre-supported, the ends expand away from the centre, the shaft drive end can expand axially for significant distances (up to about 3 mm in extreme cases), the coupling design and cold set-up should anticipate this. Correct set-up is to have the coupling in mid-travel under rated operating conditions, cold set & hot start conditions within the coupling travel limits. There may thus be limits set by the vendor on the cold and hot conditions for pump starting. Going outside these conditions may cause the pump to seize.

4.6.7.4 Condition Monitoring

See also Section 5.0 Ancillary Systems & Equipment.

For standard end-suction pumps, continuous condition monitoring is not normally justified, unless the pump is inaccessible; e.g. located in a caisson, on an unmanned platform, or subsea.

For large / high power pumps, some degree of condition monitoring is normally justified, given the value and importance of the unit. Monitoring of bearing pad temperature, oil temperature / pressure should be standard. Duplicate sensors are often justified, such that a faulty sensor can then be "replaced" or a doubtful value cross-checked, with the equipment on line. Periodic or continuous vibration monitoring of the bearings and pump casing should also be in place, selected according to the criticality of the duty and the accessibility for regular operator based monitoring.

Monitoring and trending of bearing condition and process parameters (by the DCS) can give valuable insight into pump operating problems, deterioration or loss of performance, before or after a failure.

4.6.7.5 Protective Systems

See also Section 6.0 Operation Support Guidance.

Protective systems should be subject to periodic testing, with alarms less critical than trips. Thrust bearing failure typically requires trip protection, other bearing and seal faults should be detected by alarms. Alarms are an indication of approaching failure and prompt action will be required. Proprietary monitoring systems permit an alarm to be actuated at a low value and a trip at a higher value. If trips are safety-critical, they should have two independent sensor / monitor / trip paths, to prevent one component failure disabling the trip function.

Pumps seldom have protection from out-of-range process conditions, except for drive overload. The upstream and downstream isolation valves should be installed for remote operation.

SECTION 4.6 APPENDIX 1

Net Positive Suction Head (NPSH)

Normally expressed as NPSH required (NPSHr) and NPSH available (NPSHa).

This is a measure of how close the fluid being handling is to releasing gas in the pump suction. It is a calculated or measured value, expressing the difference between the vapour pressure of the fluid at pump suction conditions, and the actual pressure. It is expressed in metres (of head of the relevant fluid) so that it can be displayed on the pump performance curve.

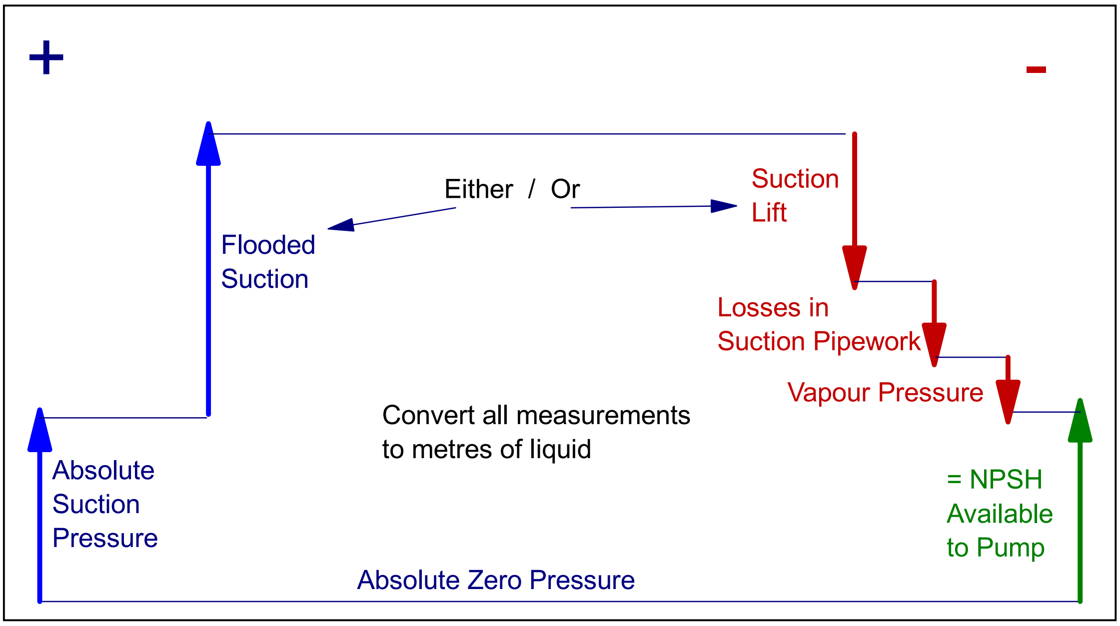
Manufacturers carry out tests on pumps to establish the required value (NPSHr).
Process / machines engineers calculate the NPSH available (NPSHa) in the fluid system.

For the worst case condition, if NPSHa – NPSHr > 1 metre, the design is normally acceptable.
If NPSHa – NPSHr > 0.5 but < 1 metre, improvement or special pump testing is called for.
If NPSHa – NPSHr < 0.5 metre, redesign or very special pumps are necessary.
If NPSHa < NPSHr, redesign is the only remedy.

For multi-component fluids or those containing supersaturated gases, calculation of NPSHa is not straightforward and operating experience should be sought.

Internal pump wear, damage, or faulty assembly can significantly increase the NPSHr.
A very small increase in suction temperature, or poor suction pipework layout, can significantly reduce the NPSHa.

NPSHa Calculation



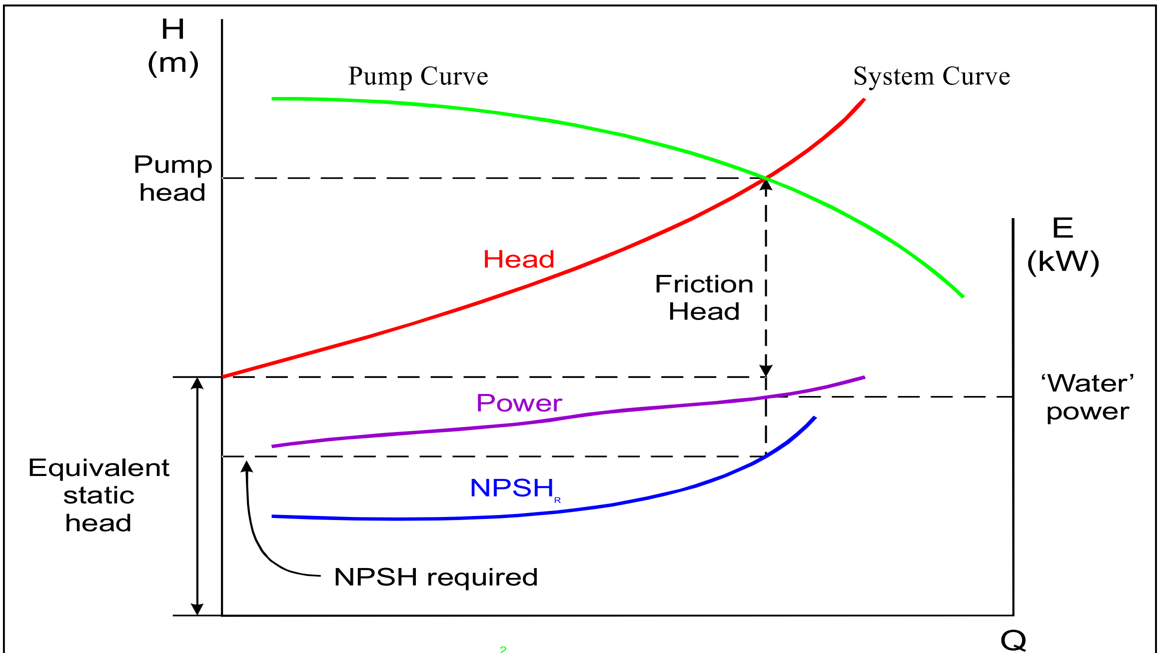
APPENDIX 2

Pump Control & Management Systems

A very brief description of the physical effects of a pump working within a control system, is laid out below.

Pump Curve vs. System Curve

Pump manufacturers can test a pump in the factory and produce the test curve or set of curves. When a pump is installed into a real system, that system can be expressed as a curve in the same format and on the same axes as the pump curve. The system curve is normally derived by calculation. When plotted on the same chart, there is normally only one point where the lines cross. This should be the actual operating point. If either the pump or system curves are changed, the operating point moves accordingly. If the lines cross at a shallow angle, or even worse, at two separate points, the operating point may be uncertain. The practical result is unstable operation, which must be solved by physically altering pump or system, thus changing the relevant curve shape.



$$\text{Friction head} = f.\frac{l}{d} - \frac{V^2}{2g}$$

f = friction factor (depends on Reynold No)
l = pipe length (m)
d = pipe bore (m)
V = liquid velocity (m / s)

$$\text{Duty power} = \text{water power} \times \frac{\rho}{1000}$$

ρ = density of liquid (kg / m^3)

Control System Actions

The action of a control valve alters the System Curve, thus changing the operating point. The operation of changing the pump speed, by contrast, changes the shape of the pump curve, also changing the operating point.

SECTION 4.7

CENTRIFUGAL PUMP – LARGE SINGLE STAGE

CONTENTS

This report section covers a Large Single Stage Centrifugal Process Pump. To avoid unnecessary duplication, generic remarks in **Section 4.6** will not be repeated, but are referenced.

The target duty for large single stage centrifugal pumps is crude oil – a mixture of liquid hydrocarbons, some volatile at atmospheric conditions. Crude oil will be warm (60 to 80 C).

Crude oil will also contain contaminants, some toxic such as hydrogen sulphide, radioactive such as strontium salts, or just water or grit. Additives may be introduced which have toxic properties, though these would normally be only in low concentrations.

4.7.1 INTRODUCTION

- ***This Guidance Note is written for a Large Single Stage Pump on Crude Oil Duty.***
- ***Large single stage pumps are simple robust pieces of equipment and can run for extended periods without problems. Mechanical seals remain the most vulnerable area.***
- ***The quantities of fluid handled are high, such that any leakage may be large and may make a large area inaccessible.***
- ***The major hazards are from the released liquid, which could catch fire, and from evolved gases, which could result in a vapour cloud explosion.***
- ***Hydrogen sulphide, which may be present, is highly toxic as well as posing a stress corrosion problem within equipment.***

Figure 4,7 – 1 Single Stage Radial Split Casing Pumpset

SB RANGE (Single & Two-stage)

Features

Designed to API 610 specification.
Single or two stage.
Axially or Radially split casing.
Rotating assembly easily removed without disturbing pump alignment.
Centreline mounted.
Suitable for speeds up to
8000 rev/min.

Applications

Crude oil pipeline boosting.
Crude oil pipeline transfer.
Water transfer.
Water injection.
Hydrocarbon duties.

Duties

Heads 200 – 1000 m (660 – 3281 ft)
Flows up to 6000 m3/hour
(26400 US gal/min)

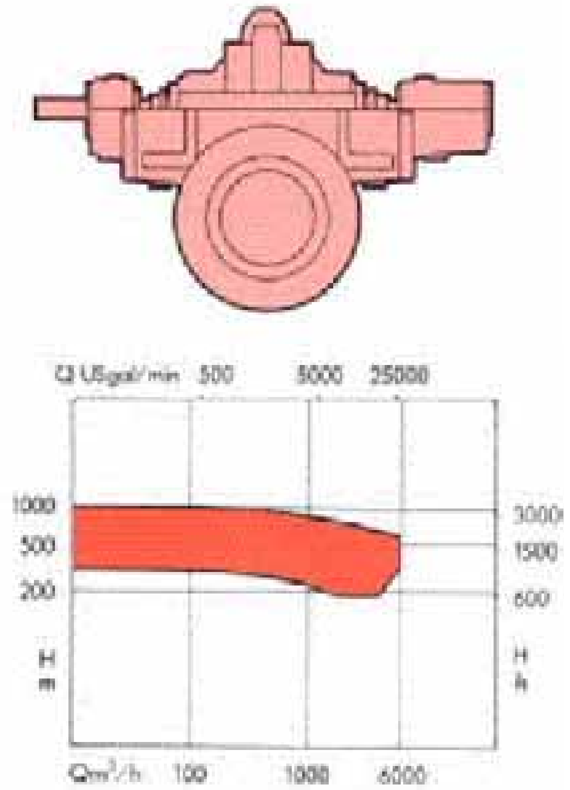


Figure 4,7 – 2 Vendor Data on Crude Oil Pump

Specific Designs for Crude Oil Duties

Very large pumps, as in the crude oil pump discussed, have a radial split casing, radial suction and delivery. An alternative choice for large pumps is the horizontal split-casing design with radial suction and delivery.

These pumps require robust baseframes to carry shaft torques and piping loads without excessive distortion and to provide the necessary stiffness for alignment and dynamic stability. This is particularly true offshore with the baseframe having to be entirely independent of the offshore installation where the structure itself is mobile, due to the influence of waves and weather.

Large pumps are shaft driven by a separate electric motor, gas turbine or diesel engine.

The safety of pumps handling hazardous materials is dominated by their shaft sealing systems. These require appropriate design, maintenance and operator attention.

Large Single Stage Pumps – design choices

Large single stage pumps, with flows greater than perhaps 500 m3/hour, are not available in the end suction design described in **Section 4.6**.

There are three practical design choices for Large Hydrocarbon Pumps, any of which may include a double-entry first stage impeller to handle the largest possible flow rate :-

Axial Split Casing Design

Often referred to as Horizontal Split Casing design, but can also be mounted vertically. These pumps have the inlet and discharge branches cast into a lower half casing, along with the mounting feet. The casing splits at a horizontal joint line at the shaft centre line, the top casing "half", though heavy, is simple to lift off as it is basically just a cap. Removal of the top casing allows the rotor to be lifted out complete. The shaft has two mechanical seal systems and two externally mounted bearing housings. Any pump with this bearing arrangement is referred to as a “Between Bearings” design. The pump can be serviced in situ, or smaller units can be removed complete to workshop conditions.

Barrel Casing pumps have an internal cartridge with (usually) several impellers on a common shaft, all fitted within a pressure casing. This design is treated in detail in **Section 4.8** and **Section 4.10**.

Radial Split Casing pumps are a hybrid between end suction and barrel casing, they have a simplified barrel casing with suction and delivery flanges. The impeller is contained between bolted front and rear covers. The shaft has two externally mounted bearings and two mechanical seal systems. This type of pump is not a Back Pull Out or cartridge design, so must be maintained in situ. Even the individual components are very large and require working space.

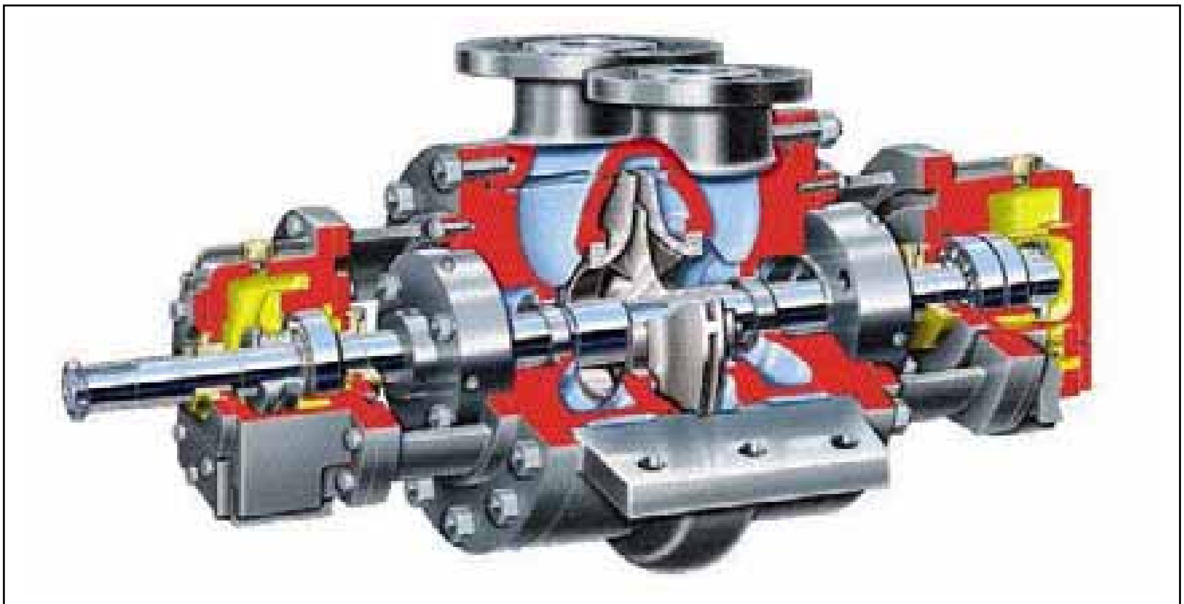


Figure 4,7 – 3 Radial Split Casing Pump Cut-away Showing Double Entry Impeller

4.7.2 BACKGROUND & HISTORY

- ***Large centrifugal pumps were typically used for water pumping, and were of axial split casing design with a cast iron casing.***
- ***The radial split casing design was developed for containment of higher pressures and hazardous fluids.***
- ***Modern pumps are built of carbon or stainless steels with sophisticated process duty mechanical shaft seals and supporting systems.***

Typical large single stage pumps have shaft speeds in the range 1500 – 7000 rev/min, shaft power in the range of 200 kW to perhaps 20 MW. For hydrocarbon pumps the casings are typically of carbon steel, and the stator and rotor parts from carbon steel or cast iron to suit the duty. Trace elements in the range of process fluids expected over the duty life will dictate the exact choice of materials & coatings.

4.7.3 HAZARD ASSESSMENT

- ***The hazards associated with a large centrifugal pump have to be considered over its complete operating / maintenance cycle, and not just steady load operations. Mal-operation / excursions / drive system failures and emergencies must all be covered.***
- ***The majority of hazards relate to the process fluid, either by a direct release, or by the consequent effects on upstream & downstream systems from a pump failure.***
- ***Failure of static components through fatigue, erosion or corrosion.***
- ***Failure of dynamic components leading to high fatigue loads on other components with potentially rapid catastrophic deterioration of seal or nozzles.***
- ***Failure of the pipe system due to extreme pressures or temperatures – either externally applied or generated by the operating pump or system, resulting from events such as pressure surges, process density, or composition changes.***

4.7.3.1 Process Substance Containment Hazards – Crude Oil Pumping

The direct threats to personnel from a release arise from :-

- The flammable nature of fluid released – volatile components would form a gas cloud with potential for explosion, or fire.
- Physical injury from a jet of fluid, or slips / falls from contaminated floor surfaces.
- Crude oil may well be hot, giving a scalding risk above 70 C.
- The oil may also evolve asphyxiating gases.
- The toxic nature of components or additives within process material. Liquids containing hydrogen sulphides are highly toxic.
- Small traces of radioactive salts within the process material can accumulate within a pump requiring appropriate handling precautions.
- Inappropriate operation of the pump can induce high temperatures and pressures within a pump, giving rise to hazards from mechanical disintegration of the pump.
- Handling material with higher concentrations of water or solids can lead to higher pressure generation due to the effective increase in density.

See also **Section 4.6.3.1** for generic risks.

4.7.3.2 Equipment Hazards

Large Single Stage Process Pumps

The basic concept of a single stage centrifugal pump is extremely simple; there is only really one moving part.

MECHANICAL HAZARDS FROM PUMPS

- ***Dynamic stability – bearing damage.***
- ***Process induced vibration – running at BEP?***
- ***Overspeed and reverse rotation – mechanically or process induced.***
- ***Internal clearances.***
- ***Bearing failure / lubrication.***
- ***Seal failure.***
- ***Joint failure.***
- ***Corrosion mechanisms.***
- ***Erosion mechanisms.***
- ***Failure of connections – overload and fatigue issues.***

See **Section 4.6.3.2** for generic data. Additionally :-

The internal design of pumps normally balances out most of the axial forces on the impeller, leaving the residual force to be taken by the thrust bearing. Faulty design, internal wear or damage, or running outside the design duty range, can put excessive loads on the thrust bearing. This can lead to premature bearing failure. Pumps with double entry impellers attempt to balance axial loads by fitting an axially symmetrical impeller. This balance can be affected by loss of symmetry e.g. a bend in the suction pipe located very close to the pump flange.

Since large radial split casing pumps are maintained in situ, a relatively large amount of work is carried out at the pump berth, in congested conditions. Care is required to ensure that the work is done to an acceptable standard and does not compromise the build quality.

Mechanical Seals

The mechanical seals on a large hydrocarbon pump are typically of double back-to-back design, using a pressurised seal fluid. This gives the benefit of nil leakage of process fluid to atmosphere, warning of failure of one seal element, and independence from the properties of the process fluid.

The limitation of double seals is their complexity and dependence on high quality fitting practice. Even in the event of complete seal failure, the internal clearances are small enough that the release rate is not huge, unless the shaft has been bent or displaced.

Leakage from seals is a sign of failure, seals do not bed in or recover. It is important is that a pump with a failing seal is not run longer than is absolutely necessary for safe shutdown or duty change-over.

For details of Bearings, Seals, Shaft Couplings and related hazards see **Section 5** – Auxiliary Systems & Equipment.

4.7.3.3 Operational / Consequential Hazards

See **Section 4.6.3.3** for generic information**.**

It may take a considerable amount of time for large piping systems to vent at low pressure before the pump can be started. A procedure should be in place to confirm that venting is complete and that the pump is primed.

Large pumps have high power drivers and are designed to put large amounts of energy into high capacity fluid systems. Hence any putting into or out of service, or load change, must be controlled smoothly to minimise shock effects.

4.7.3.4 Maintenance / Access Hazards

See **Section 4.6.3.4** for generic information. Additionally :-

Because of the large physical size of the equipment, significant quantities of fluid may remain in casings after draining. Provision should be made to catch this material on opening joints or tilting casing parts.

4.7.4 OPERATING REQUIREMENTS

See **Section 4.6.4** for generic information.

4.7.5 MAINTENANCE REQUIREMENTS

- ***Large single stage pumps, which can only be maintained in situ, require good all round access and lifting facilities.***
- ***Residual hazards will be present from trapped liquid / radioactive salt deposition***

Large Centrifugal Pumps

Pump designs which can only be maintained in situ require good all-round access, and somewhere to lay down the removed parts (not necessarily immediately next to the machine, and not in a defined escape route or major walkway). Additional lighting can be brought in to illuminate the working area. It is preferable to use lifting beams for extended in-situ lifting work than to use platform cranes, which are too big, too remote, and probably in demand for other activities. If the installation is subject to wave motion, safe lifting may be impossible in bad weather.

The bearings, seals and rotor can be removed to workshop for inspection / overhaul. Maintenance procedures must address issues like match marking, component identification. Note that it is not good practice to exchange parts between assemblies as tolerance and wear effects tend to be additive, resulting in poor build. Also rotating assemblies tend to be factory balanced complete; swapping parts around can destroy shaft balance.

The large size and weight of components increases the risk of injuries / damage during handing, especially if access is difficult, lighting is poor, and lifting facilities are not ideal.

4.7.5.1 Internal Corrosion

See **Section 4.6.5.1** for generic information.

4.7.6 LARGE SINGLE STAGE CENTRIFUGAL PUMP MAIN COMPONENTS

4.7.6.1 Pressure Casing

This is normally a single piece casting with flanged suction and delivery branches. Cast carbon steel is the norm for hydrocarbon service although stainless steels and exotic materials may be required for aggressive duties. Casings may be welded into pipework although this makes maintenance difficult – this may lead to casing distortion and subsequent unreliability due to distortion of pump or joint faces. Casting can be porous and should be adequately pressure tested before use to detect leaks.

4.7.6.2 End Covers

The End Covers serve as the front and rear fluid containment and also as the mechanical support for seals and bearing housing. It is normally of the same material as the pressure casing. Each cover is bolted to the pressure casing, sealed with an "O" ring or fully contained gasket.

The bolts or studs and nuts retaining the end covers and seals are an integral part of the pressure containment. Only fasteners supplied or approved by the manufacturer may be used. Typically these will be of high tensile material, with rolled screw threads. Removal and replacement of fasteners requires care to avoid damage. Fasteners may be of different lengths and it is good practice to match mark fasteners. Tightening must be by progressive and ordered sequence, normally as defined by the manufacturer. Tightness may be judged by torque, measured stretch or measured tension.

4.7.6.3 Impeller

The impeller is usually a keyed parallel fit to the shaft, retained on both sides by screwed rings, possibly with spacer sleeves. The screwed rings permit fine adjustment of the impeller vs. the diffuser slots. An axial error of > 1 mm can affect the efficiency of the pump. Large pumps often have double inlet impellers (effectively 2 impellers moulded back-to-back), these effectively double the suction capacity of the pump, and should also eliminate axial thrust on the shaft.

4.7.6.4 Mechanical Seals

These large "between bearings" require two sets of seals. For double seals, an independent seal support harness / seal pot is required for each end of the pump.

4.7.6.5 Bearings

"Between bearings" pumps have two bearing housings, one located outboard of each mechanical seal. It is normal for each bearing to be a self-contained rolling element bearing with oil reservoir. One bearing housing (normally NDE) contains a thrust bearing, the other has axial float. Loss of axial float may lead to bearing failures, particularly with hot duties.

4.7.6.6 Support Systems

See **Section 4.6.6.6** for generic information.

See also Section 5.0 Ancillary Systems & Equipment.

Pump Baseframe

This will normally be common with the baseframe under the driver (and gearbox if fitted).

Lubrication System

Larger pumps may have pumped lubrication / seal oil systems. The system provides filtration, cooling, monitoring of temperature / pressure. Due to the risk of cross-contamination and for issues of reliability, it is not normal to have common systems serving several pumps.

Seal Support System

The traditional liquid based support system is a pressure pot with thermosyphon cooling, containing a compatible clean fluid (e.g. light hydrocarbon oil). However thermosyphons often do not work as anticipated, and internal pumping rings or external seal circulation pumps may be required. Each seal should have its own support / monitoring system with common services.

Some modern machines have dry gas seals, with the advantage that the support system is simpler and lighter than a liquid support system. A supply of barrier gas is required.

Pump Recycle System

A recycle system is required for pump venting / priming & to ensure a minimum flow during low output operation. This flow must be returned to a vented vessel or vapour space in the suction system, to remove gas. If the recycle flow can be returned to a large storage reservoir, heat input by the pump will be dissipated. Otherwise it may be necessary to install recycle flow coolers. Return of recycle flow directly to pump suction is likely to cause problems with gas locking of the impeller and seals. If pumps are fitted with individual recycle systems, it is possible to prime and run up a standby pump offline.

4.7.6.7 Control & Management Systems

See **Section 4.6.6.7** for generic information.

4.7.7 INTEGRATION ASPECTS

See **Section 4.6.7** for generic information.

4.7.7.1 Process Duties

Large pumps are selected for a chosen duty and any changes in fluid, pressure or flow may take the pump outside its operating envelope. Hence significant process changes need to be reviewed against all the equipment capacities.

4.7.7.2 Mechanical Integrity

Radial split casing pumps have 2 main cover joints. They also have 2 seal housing joints. These are the main potential points for mechanical failure of static parts. A pump shaft failure will potentially rupture the mechanical seals.

4.7.7.3 Alignment / Balancing

4.7.7.4 Condition Monitoring

For large / high power pumps, some degree of condition monitoring is normally justified, given the value and importance of the unit. Monitoring of bearing temperature, oil temperature / pressure should be standard. Periodic or continuous vibration monitoring of the bearings and pump casing should also be in place, selected according to the criticality of the duty and the accessibility for regular operator based monitoring.

Monitoring and trending of bearing condition and process parameters (by the DCS) can give valuable insight into pump operating problems, deterioration or loss of performance, before or after a failure.

4.7.7.5 Protective Systems

See also Section 6.0 Operation Support Guidance.

SECTION 4.8 CENTRIFUGAL PUMP – MULTI-STAGE BARREL TYPE

CONTENTS

This report section covers a Multi-stage Centrifugal Process Pump. To avoid unnecessary duplication, generic remarks in **Section 4.6** will not be repeated, but are referenced.

The target duty for the multi-stage barrel type centrifugal pumps is crude oil transfer or main oil line export. The selection of the multi-stage pump would be to match a higher pressure / lower flow duty than the single stage pump application. The hazards of Crude Oil are introduced in Section 4.7

4.8.1 INTRODUCTION

- ***Multi-stage Centrifugal Pumps are employed where the required head is too much for a single stage pump.***
- ***Barrel Casing Design gives particularly good containment and is often chosen for hazardous fluids.***

Multi-stage Centrifugal Pumps comprise several centrifugal pump stages in a single casing. For containment purposes, pumps on hazardous fluids (e.g. hydrocarbons) should be of Barrel Casing Design. These pumps are physically similar to Barrel Casing Compressors and have similar advantages/ disadvantages. (See **Section 4.1**)

Barrel Casing Pumps have two Mechanical Seals, one at each end of the pump shaft. The bearings sit outboard of each seal.

Ring Section and Horizontal Split Casing Pumps are available, they are easier to maintain but are far more vulnerable to leaks.

4.8.2 BACKGROUND & HISTORY

- ***Early multi-stage pumps were of ring section (stacked segments) or split casing design.***
- ***Modern multi-stage pumps favour "Barrel Casing" design.***

Early multi-stage centrifugal pumps were built from multiple ring stator segments slotted together, alternating 1 stator with 1 impeller. Typical duties were boiler feed water pumps and high pressure service water pumps. This arrangement gives many potential leak paths to atmosphere.

Horizontal split casing pumps are easy to inspect as one complete casing half can be lifted without disturbing pipework. Split casing pumps were typically used in chemical plants, similar basic design for 1, 2 or multi-stage. There is a long joint line with leakage potential.

Figure 4,8 – 1 Multi-stage Barrel Casing Pump on Baseplate

Recent design of high pressure multi-stage pumps has favoured the "Barrel Casing" design, where the pressure containment is a single cylindrical housing with an end cap, containing a stator and rotor "cartridge". The end cap is retained by bolts or by a locking ring system and sealed with "O" rings, this being a much more secure and easily operated system than the long bolted joint required for the irregular shape of a horizontal split casing. The cartridge is built up separately and inserted into the barrel. In this way a new cartridge can be fitted relatively quickly. Bearings and seals are built into the end caps.

Typical modern large multi-stage pumps have shaft speeds in the range 3000 - 7500 rev/min, shaft power 0.5 - 5 MW per casing. Impellers may be cast or fabricated from 2 machined discs welded or brazed together. Although built from "standard" components, every machine is tailor made to the duty. For hydrocarbon machines the casings are typically of carbon steel, and the stator and rotor parts from carbon steel or cast iron. Trace elements in the range of process fluids expected over the duty life will dictate the choice of materials & coatings.

4.8.3 HAZARD ASSESSMENT

- ***The hazards associated with a multi-stage pump have to be considered over its complete operating / maintenance cycle, not just steady load operations. Mal-operation / excursions / drive system failures and emergencies must all be covered.***
- ***The majority of hazards relate to the fluid, including effects on upstream/ downstream systems from a pump failure***

4.8.3.1 Process Substance Containment Hazards

- ***Rapid temperature rise in dead head conditions***
- ***Pin hole leaks may produce significant leakage and vapourisation***
- ***Increase in density of pumped fluid will cause higher discharge pressure generation, this must be kept within operating tolerance.***

Operational Hazards associated with centrifugal pumps are common across most types. See **Section 4.6.3.1** for general issues.

Additionally :-

Multi-stage pumps have a low tolerance to a dead head pumping situation with a consequent rapid rise of internal temperatures and pressures.

Discharge pressures can easily exceed 100 barg, even a pin-hole leak can give a dangerous fluid jet or atomised spray of considerable length.

Higher head rise increases the sensitivity of the design to changes in fluid density, the design should accommodate all operating conditions – start up, normal operations, operating excursions, washing / purging operations, and shut down.

4.8.3.2 Equipment Hazards

- ***Vibration induced within the pump can induce fatigue failure of seals or piping connections, particularly the ancillary piping***

Mechanical Hazards associated with centrifugal pumps are common across most forms See **Section 4.6.3.2** for general issues

Additionally :-

Vibration levels can be high, with sensitivity of pump to rotor balance and stability – vibration levels will affect seal performance and can induce fatigue failure of connections. Though the main connections are robust vent, drain and seal connection lines are all susceptible to fatigue.

4.8.3.3 Operational / Consequential Hazards

Operational Hazards associated with centrifugal pumps are common across most types See **Section 4.6.3.3** for general issues.

Additionally :-

Multi-stage pumps can produce large pressure fluctuations if operated below minimum flow. These will cause piping vibration, visible movement may result if a natural frequency is excited. Traditional system design is for a fixed flow down a recycle line, this avoids any possibility of unstable operation. It is, however, a waste of energy and pump capacity. Thus with a modern control system, it would be better design to operate the recycle under automatic control, to open only as required.

While it is possible to throttle on the discharge valve, on a large or high head pump this is likely to damage the valve over time, tight closure will then not be possible. Similarly the recycle can only be throttled using a special valve, to minimise wear.

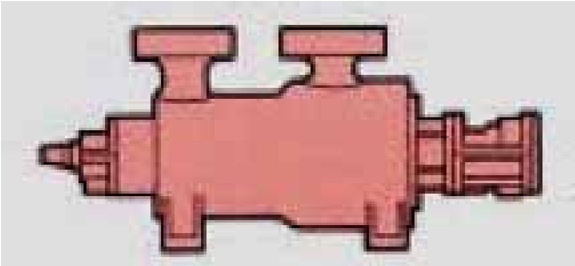
4.8.3.4 Maintenance / Access Hazards

See **Section 4.6.3.4**

Additionally :-

Multi-stage barrel casing pumps are normally installed horizontally with centre-line casing supports to minimise expansion movement. Suction & delivery pipes connect to vertical branches on the barrel. It should be possible to remove the cartridge complete, after removal of ancillary pipework, coupling etc., This will only be possible if the layout has been designed with maintenance in mind, giving sufficient access to withdraw the long cartridge, on a special slide frame.

Vertical installation is possible where tight layout is a constraint. Since the motor is normally mounted above the pump, maintenance access to remove the pump cartridge could be a problem.



OK RANGE (Barrel Casing)

Features

Cartridge withdrawal allows dismantling without breaking pipe joints or disturbing alignment of prime mover. The cartridge is a sub-assembly comprising all pump parts other than the casing. Stiff shaft construction ensures minimum deflection at all loads. Inherently strong barrel casing design with simple radial closure. Flange ratings suitable for high pressure suction conditions (e.g. series pumping).

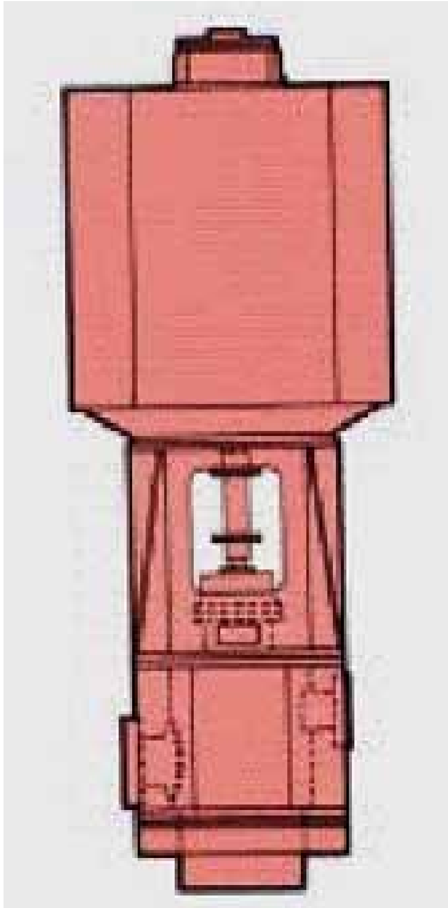
Applications

High pressure applications such as water injection, boiler feed, main oil line and product pipeline duties.

Suitable for sea water, crude oil and oil products.

Duties

Heads up to 3950 m (13000 ft)
Flows up to 3400 m3/hour
(15000 US gal/min)



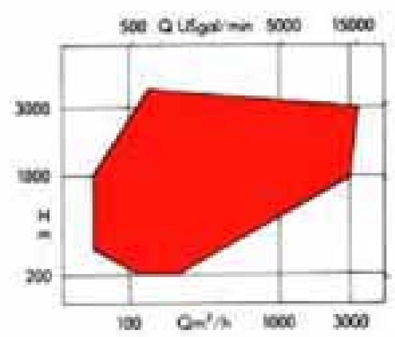


Figure 4,8 – 2 Vendor Data on Multi-stage Pump

4.8.4 OPERATING REQUIREMENTS

Barrel casing pumps have a high discharge head, and mal-operation can cause pressure surges/ liquid hammer, particularly in long pipelines. The use of variable speed drive can minimise such problems.

Liquid hammer is most likely to be caused when filling / pressurising a line. Complex pipework should be allowed to fill slowly under low pressure, venting off air / gas from high points (to flare if flammable gas is involved). Long pipelines may have to be liquid filled by pigging, to push out air pockets at low pressure.

4.8.5 MAINTENANCE REQUIREMENTS

- ***Multi-stage pumps are designed to be maintained by removal of the cartridge to a workshop, there is seldom the access or suitable conditions for in-situ work.***

It is assumed that the cartridge will be removed into workshop conditions for any maintenance. The only site work thus required is inspection of the condition of the barrel casing and ancillaries, e.g. seal support systems. To aid removal and refitting of the cartridge easily and without damage, a tailor made slide frame is required.

Prior to re-assembly, the cartridge to casing seals must be inspected. Shaft alignment cannot be assumed, even if the casing was not disturbed, and laser alignment equipment should be used. If pipework has been disturbed, the alignment should be checked before and after re-bolting the suction and delivery flanges.

Pump cartridges can be dismantled using special equipment, e.g. a press will be required to remove / refit impellers. This should be done on-shore, in which case suitable transport packing is required. This packing provides shaft support and mechanical protection during handling and while on supply vessel.

Leak testing and performance testing can only be done with the pump fully assembled, or with the cartridge built up in a special dummy test casing. Note that it is not possible to test inter-stage and balance line seals, meticulous assembly and inspection is required.

It is important on rebuild that seal support systems and instruments are put back in full working order, filled with fluids as required, and the correct valves opened / closed.

4.8.5.1 Internal Corrosion

See **Section 4.6.5.1**

Additionally, note that as Barrel Casing Pumps will probably retain pockets of liquid after draining, very thorough flushing is required after use of any corrosive liquid. If the pump is not required to go into service, it might be better to leave it full of a suitable neutralising solution e.g. for an acidic fluid, fill the pump with Sodium Carbonate, to deal with any remaining acid.

4.8.6 MULTI-STAGE CENTRIFUGAL PUMP MAIN COMPONENTS

Barrel casing pumps consist of a stack of stator sections with impellers between. Each impeller has axial inlet and radial discharge. The radial impeller discharge matches a radial diffuser section in the stator. The flow is then bent through 180 degrees to flow radially in towards the eye of the next impeller, before being turned back by 90 degrees, axial to the next impeller inlet. The final stage diffuser flow is collected into the discharge branch.

Inter-stage seals between stator sections are by O rings, and between impellers by close clearance shaft bushings. The internal cartridge is sealed to the Barrel Casing with O rings or contained gaskets, to segregate suction, discharge and seals.

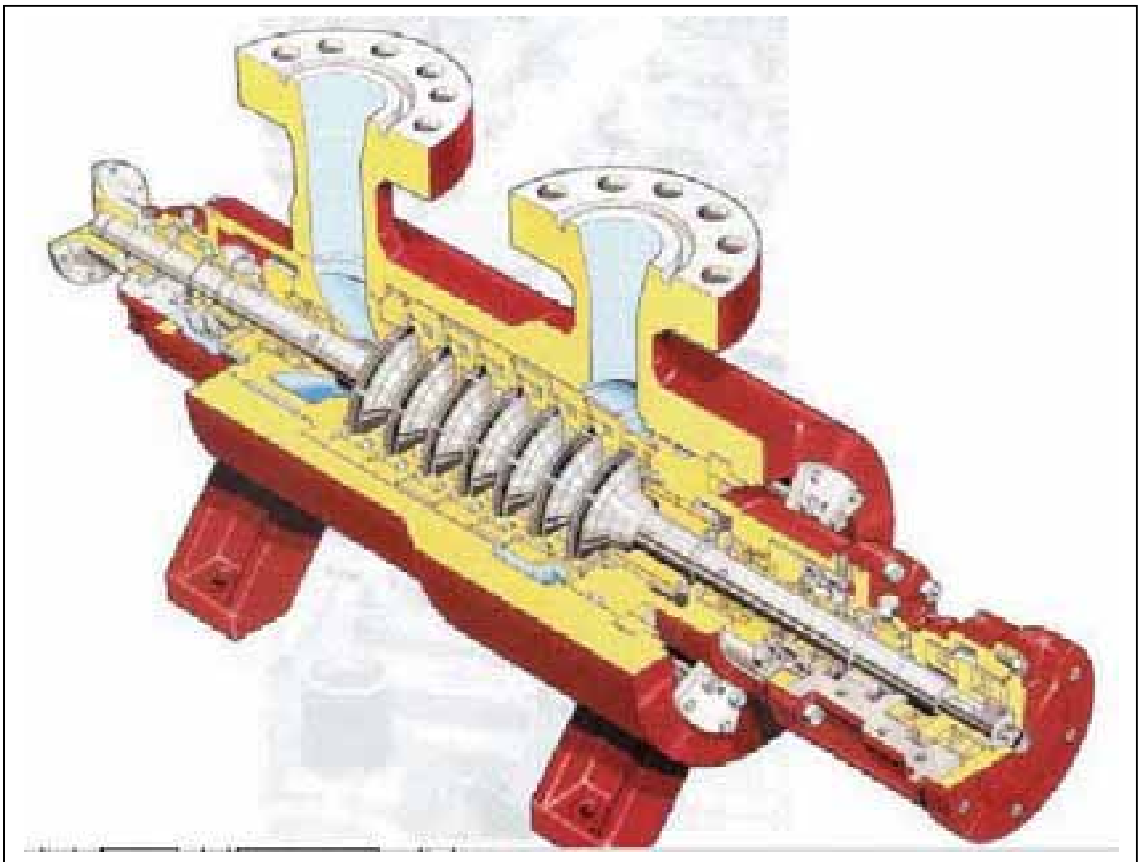


Figure 4,8 – 3 Multi-stage Barrel Casing Pump (cutaway)

The mechanical seals are pressure balanced by stator drillings so that both seals are exposed to the same pressure, this might be suction pressure or perhaps 1st or 2nd stage discharge to avoid sub-atmospheric operation. Axial hydraulic balance is achieved by a combination of impeller design and the use of a thrust piston. The thrust piston has a very fine radial clearance in its bore, even fine abrasive materials can damage the pump. This damage will show up as excessive bearing loads hence high bearing temperatures.

The bearings will be plain radial bearings (probably tilting pad) , one outboard of each seal, and a single tilting pad thrust bearing at the Non-Drive End. Although the thrust load should be uni-directional, there should be a reverse thrust bearing, possibly with smaller pads than the main bearing.

For details of Bearings, Seals, Shaft Couplings and related hazards see **Section 5** – Auxiliary Systems & Equipment. Most multi-stage pumps rely on the inter-stage bushings for rotor stability, particularly during run-up & run-down through first critical speed. Dry running, or (more usually) running with abrasive solids, can wear these bushings, reducing the critical shaft support and pump efficiency. Further damage may well occur during stops & starts, and this will be shown by increased vibration. Note that vibration monitors may be disabled or muted during start, to allow for passing through critical speeds during shaft acceleration.

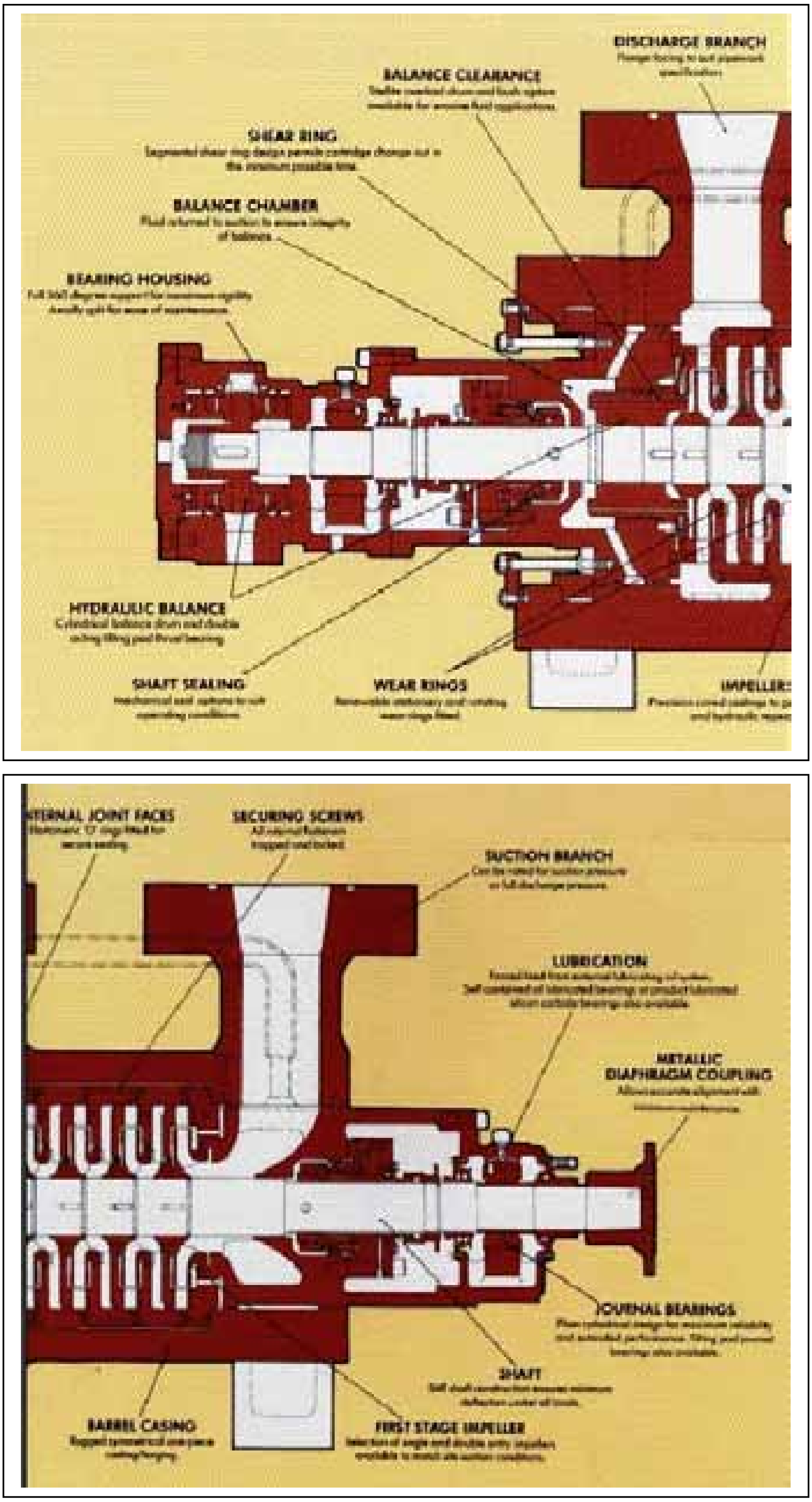


Figure 4,8 – 4 Part Cross Sections of Multi-stage Pump

4.8.6.1 Barrel Casing

This is normally a single piece forging with flanged suction and delivery branches (possibly welded into the main forging). Carbon steel is the norm for hydrocarbon service although stainless steels and exotic materials may be required for aggressive duties. Casings may be welded into pipework, this is fine provided that the cartridge can be pulled out in situ. Casings are very thick and gross failure in service is almost unknown. The only realistic leakage path is across joint faces, particularly if these have been dented or scored during maintenance.

4.8.6.2 Cartridge and End Cover

The cartridge is built up of radially split stator segments, one segment per stage plus an end cover plus seal housings and bearings. The assembly is located by spigots and is bolted together, and some care is required to avoid bending the assembly. Dismantling / re-assembly is fairly slow, impellers are pressed on to the shaft one at a time while the cartridge is assembled. Inter-stage seals, and cartridge to casing seals, are normally made with O-rings or fully retained gaskets. Given that the cartridge plugs into the casing, most potential leak paths are internal. The cartridge is retained into the casing by the end cover, this cover is integral to the cartridge and locked to the casing by high tensile bolts or proprietary locking rings.

4.8.6.3 Impellers

The impellers are shrink fitted to locations on the shaft with parallel keys and with spacing sleeves between stages. Impellers are nominally identical, except for the first stage (often low NPSH inlet design) and last stage (may have reduced diameter). To enable fitting, impellers have progressively larger bores, matching steps on the shaft. Although these steps are fractions of 1 mm, it means that impellers are unique and must be fitted in the correct order. Impellers are individually dynamically balanced, then the whole rotor is balanced. The axial positioning of each impeller is defined by the sleeves, overall the shaft must be set up to align impellers with diffuser slots, or efficiency will suffer. Some multi-stage pumps are of "stiff-shaft" design, operating below first critical speed. This reduces the criticality of the inter-stage bushings.

Radial hydraulic balance is ensured by the use of symmetrical stage inlets and radial diffusers, axial balance is managed by a combination of impeller neck rings, inter-stage bushings and thrust piston. Some designs have some reversed impellers but this requires inter-stage flow passages through the cartridge.

4.8.6.4 Mechanical Seals

Two mechanical seals are required, one at each end of the shaft. Double seals are standard, with liquid or gas barrier. Note that many seals are uni-directional – this requires that the seals are fitted the correct way round, and that the pump is never run backwards.

For details of Mechanical Seals and related hazards see **Sections 5.3.3** & **5.3.4**.

4.8.6.5 Bearings

The shaft is supported by a radial bearing at each end and has a single thrust bearing, normally at the non-drive end. Tilting pad bearings are common, these require a pumped lubricating oil supply. For details of Bearings and related hazards see **Section 5.9**.

4.8.6.6 Support Systems

Baseframe

This will normally be common with the baseframe under the driver (and gearbox if fitted).

Lubrication System

Lubrication oil may be supplied from the driver (if a gas turbine), otherwise a separate unit will be installed. Each lubrication unit should support 1 pump with related driver & gearbox (as applicable). Systems shared between pumps give rise to common mode failures and should be avoided. The design should avoid the risk of oil contamination (by process fluid or cooling water), and ideally there should be an air break between oil connections and other services.

Seal Support System

See **Section 4.6.6.6**

Pump Recycle System

See **Sections 4.6.6.6** & **4.8.3.3**

4.8.6.7 Control & Management Systems

See **Section 4.6.6.7**

Additionally, since the head generated by multi-stage pumps is very high, they are very sensitive to speed fluctuations, particularly if feeding into a shared manifold or other common user system. On variable speed drives, the speed control system should be designed for tight speed control / slow ramping.

Similarly bringing pumps on and off line requires care & appropriate use of the recycle, to avoid pressure surges.

4.8.7 INTEGRATION ASPECTS

4.8.7.1 Process Duties

Large multi-stage pumps are designed for a chosen duty, and as changes in fluid constituents, pressure or flow may take the pump outside its operating envelope. Hence any process changes need to be reviewed against the equipment design envelope. Pumps require adequate Net Positive Suction Head available – See **Section 4.6 Appendix 2** for an explanation of NPSH. If the properties of the fluid have been mis-understood or changed, the NPSHa may not be adequate and the pump may not work. This is not normally a safety issue, unless lack of operation compromises safety.

Once flow has been established, a small evenly distributed gas load can be tolerated, and the vendor can advise how much this will de-rate the pump.

Flow cooling is not normally required on pumps as the temperature rise per stage is typically 1 – 4 C. Higher temperature rises indicate very poor efficiency.

Figure 4,8 – 5 Vertical Multi-stage Pump Packages

4.8.7.2 Mechanical Integrity

The massive casing and minimal number of casing joints makes the Barrel Casing pump very robust. A complete shaft failure inside the pump is very unlikely, although a fatigue failure could result in sufficient seal damage to permit a significant release.

As the main casing fasteners or lock ring system are highly loaded, only the correct parts should be used. Substitution of copy or inferior parts could result in casing joint failure. Routine hydraulic testing to design pressure is not recommended.

The cartridge, as removed for maintenance, is not physically robust and should be transported in a cradle or special crate.

4.8.7.3 Alignment

As these pumps have relatively slender shafts, it is always worth aligning the coupling to the best possible standard. This minimises bearing loads, maximises coupling life, and reduces the risk of failure. Thermal expansion of pipework and casing should be accommodated by the casing and pipework supports without affecting the alignment. Mis-alignment will show up by changes in machine vibration.

Axial alignment must take account of potential thermal expansion of pump shaft and casing. With the thrust bearing being at the Non Drive End of the pump, shaft expansion can be significant.

4.8.7.4 Condition Monitoring

The capital and operating costs of Barrel Casing pumps is normally so high as to justify full condition monitoring, certainly including bearing temperatures, seal conditions and shaft vibration levels. If the raw vibration signals are available at the monitoring cabinet, frequency analysis equipment can easily be connected as required. Continuous recording / analysis of the full spectrum signal is not normally justified.

Monitoring and trending of bearing condition and process parameters (by the DCS) can give valuable insight into pump operating problems, deterioration or loss of performance.

4.8.7.5 Protective Systems

See **Section 4.6.7.5**

Additionally, it should be noted that the re-start of equipment that has been tripped, to test if the trip was real or spurious, can cause additional damage. Operating procedures should specify what checks are required, including if possible analysis of pre-failure condition monitoring information, before any kind of re-start is attempted. Variable speed equipment gives more scope for a very low speed, low torque, test run.

4.8.7.6 Bearings

The bearings are dependent on a continuous supply of lubricating oil, fed by pumps in a lubrication module. The process pump will not start until oil supply has been fully established, and oil supply should be maintained until the pump has stopped. The run-on time will be short as such pumps stop quickly, extended cooling will not normally be required. For emergency lubrication, e.g. complete power failure, local bearing reservoirs, or a central accumulator, may be fitted.

With Gas Turbine drive, at least one pump will be driven by the Gas Generator auxiliary gearbox. With electric motor drive, twin electric motor driven pumps would be normal.

SECTION 4.9

CENTRIFUGAL PUMP – VERTICAL CAISSON TYPE

CONTENTS

This report section covers a Vertical Caisson Type Centrifugal Process Pump. To avoid unnecessary duplication, generic remarks in **Section 4.6** will not be repeated, but are referenced.

The target duty is Crude Oil Storage Tank Transfer or equivalent low NPSH duties. The hazards of Crude Oil have been described in Section 4.7. Operating pressures are low to moderate.

4.9.1 INTRODUCTION

- ***Vertical Caisson Centrifugal Pumps are employed where the available NPSH is too low for a conventional pump.***

Vertical Caisson Centrifugal Pumps are selected for low NPSH duties. They comprise a multi-stage vertical pump fitted into a pumping chamber or caisson. The motor is mounted on a stool above the pump.

4.9.2 BACKGROUND & HISTORY

- ***Vertical caisson pumps are derived from multistage well or lift pumps. Rather than lift from a well, these pumps lift from a vessel forming a suction pot.***

Historically, vertical multistage pumps have been used to lift water from wells and boreholes, and to drain mines. Suction is at the bottom, drive shaft and discharge at the top. The drive shaft (which may be long) is connected to an engine or other driver.

For fluids with a very low Net Positive Suction Head available (NPSHa), for example steam condensate, natural gas liquids, it is often impossible to feed a conventional pump mounted at floor level (See **Section 4.6 Appendix 1** for an explanation of NPSH). Mounting pumps and drivers in pits or under platforms is expensive and hazardous for maintenance.

A simple solution is to create a vertical cylindrical vessel, with all connections above floor level. This vessel acts as a combination suction pot & mounting for the pump. Since low speed multi-stage mixed flow pumps tend to have a very low NPSH requirement, a liquid which is actually at its vapour pressure at the pump entry, can be pumped. The complete unit is referred to as a Vertical Caisson Pump.

CANISTER *(Caisson)*

Features

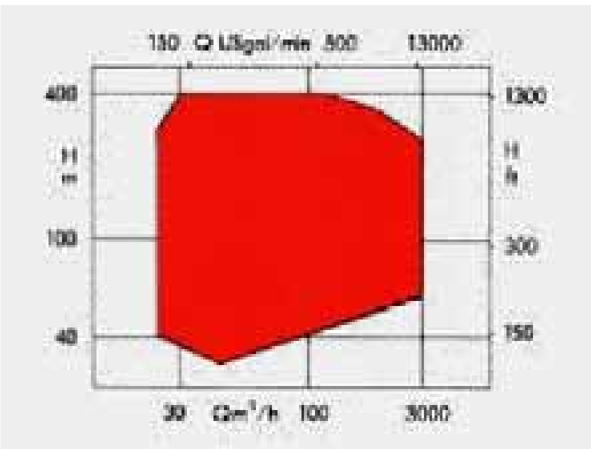
Suspended depth to suit NPSH available.
Optimum suction specific speeds to give good reliability and long life.
Stable head/ quantity curve.
Double inlet first stage allows reduced suspended depth and/ or increased running speed.
Suction and discharge connections can be above or below floor level.
Thrust bearing can be in pump or motor.
Minimum surface installation area.

Applications

Low NPSH installations.
Crude oil storage tank transfer.
Pipeline boosting.
General service duties.

Duties

Heads up to 400 m (1315 ft)
Flows up to 3000 m3/hour (13200 US gal/min)



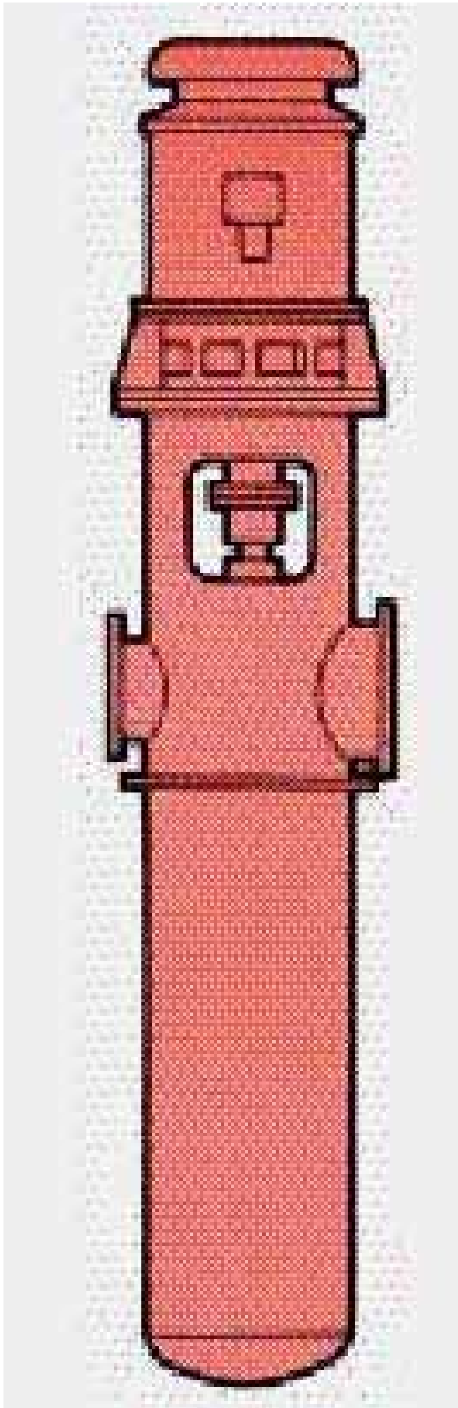


Figure 4,9 – 1 Vendor Application Data

4.9.3 HAZARD ASSESSMENT

- ***The hazards posed by Caisson pumps relate primarily to the process fluid.***
- ***The mechanical seal may be exposed to full discharge pressure.***

4.9.3.1 Process Substance Containment Hazards

See **Section 4.6.3.1** for generic issues.

Additionally, the design of the pump may put the mechanical seal at discharge pressure. This would give a potential for high leakage rates on seal failure. The discharge pressure on this type of pump is determined by the number of stages, as required to meet the process duty.

The caisson will contain a significant heel of liquid, which cannot normally be drained. It may be possible to displace most of the liquid by nitrogen blowing. It may then be possible to vaporise the remaining liquid by blowing, or application of vacuum, depending on constituents.

4.9.3.2 Equipment Hazards

See **Section 4.6.3.2** for generic issues.

Additionally, most of the moving parts are contained within the casing, which is itself contained within the caisson. Drive failures can disrupt the mechanical seal.

The conventional electric motor is flange mounted on top of a stool that encloses the flexible coupling, and thrust bearing if fitted.

For details of Bearings, Seals, Shaft Couplings and related hazards see Section 5 – Auxiliary Systems & Equipment.

4.9.3.3 Operational / Consequential Hazards

See **Section 4.6.3.3** for generic issues.

Additionally, it is necessary to flood the caisson before starting the pump, as the fluid provides cooling and lubrication, as well as requiring full flood to satisfy NPSH requirements. As there is only normally one suction connection, this requires continuously falling suction pipework to allow natural venting prior to start. For hazardous fluids, open venting is not acceptable, some means of checking for vapour pockets would be required.

Pump filling should be achieved by opening both suction and recycle lines and allowing free flooding / venting. This may take some considerable time.

In common with other multi-stage pumps, this type of pump must not be run either dry (internal bearing damage) or against closed valve for more than a few seconds (overheating and consequential bearing damage).

4.9.3.4 Maintenance / Access Hazards

See **Section 4.6.3.4** for generic issues.

Additionally, access to the thrust bearing (if fitted) and seal support system can be achieved in situ. For all other activities, dismantling is required.

Lifting facilities and good headroom are required for lifting the motor, and to remove the pump cartridge, which can be very long. Laydown space will be required. There may be a heel of liquid in the caisson, the pump cartridge will self drain as it is lifted.

Care is required to prevent debris from being dropped into the open caisson.

4.9.4 OPERATING REQUIREMENTS

As these pumps are selected for low NPSH duties, NPSH / liquid level control type problems can be expected. Typical problems might be lack of supply liquid (flow control problems), two phase flow (supply liquid not properly de-gassed), gas locking (excess non-condensable gas breakthrough).

These are process control problems and do not indicate a physical problem with the equipment.

As the pump is largely hidden below floor level, and cannot be directly heard or seen, the operators are more reliant on good process instruments, particularly pressures and flow.

4.9.5 MAINTENANCE REQUIREMENTS

- ***Vertical Caisson pumps are designed to be maintained by removal of the cartridge to a workshop, the caisson prevents any access for site work.***

It is assumed that the cartridge will be removed to workshop conditions for any maintenance. The only site work required, therefore, is inspection of the condition of the pump caisson, branches and ancillaries, e.g. seal support systems, thrust bearing. As the entire assembly relies on spigot fits, provided that these have been correctly made, no alignment checks are required or possible.

The motor must be lifted off first. The complete pump cartridge will then be lifted out, this can be long and thus require headroom. The cartridge will have to be laid down on scaffolding or a special frame, to avoid damage through bending. Dismantling will have to be done on a frame, one segment at a time.

Leak testing and performance testing can only be done with the pump fully assembled, or with the pump built up in a test casing.

It is important on rebuild that seal support systems and instruments are put back in full working order, filled with fluids as required, and correct valves opened / closed.

4.9.5.1 Corrosion

See **Section 4.6.5.1**

All internal cartridge components are exposed to the process fluid, and must therefore be compatible with it. An internal failure would not pose a safety hazard.

The caisson could be subject to internal corrosion from process fluids, and external corrosion from the environment. As this will be a fabricated vessel, it should be inspected as any other pressure vessel. Access for internal inspection requires cartridge removal, access for external inspection may be difficult because of the location. The design pressure of the caisson will normally be low, as it is not subjected to pump discharge pressure.

4.9.6 VERTICAL CAISSON PUMP MAIN COMPONENTS

4.9.6.1 Pump Caisson

This is a vertical fabricated vessel, normally with flanged top and dished end bottom. It carries a mounting flange or mounting brackets near the top flange. Carbon steel is the norm for hydrocarbon service although stainless steels and exotic materials may be required for aggressive duties. The caisson is fairly thin as it has a low design pressure and carries little load. It is normally permanently installed into a floor or baseplate.

4.9.6.2 Pump Head

The pump head is an extension of the caisson, carrying the suction and delivery branches. It also carries the mechanical seal, thrust bearing (if fitted) and motor stool, and forms the top part of the pump cartridge. It is bolted to the caisson top flange. The liquid entering the suction branch thus flows freely into the top of the caisson, filling it completely.

4.9.6.3 Pump Cartridge

The cartridge consists of a set of components forming a multi-stage pump with product lubricated sleeve bearings. Stator sections are bolted together. The impeller design is normally mixed flow. Suction is at the bottom, discharge is at the top of the pump, co-axial to the shaft. The shaft is one piece, passing through the pump head to the driver. Discharge flow passes through the spacer section(s) into the pump head, where this connects to the discharge branch.

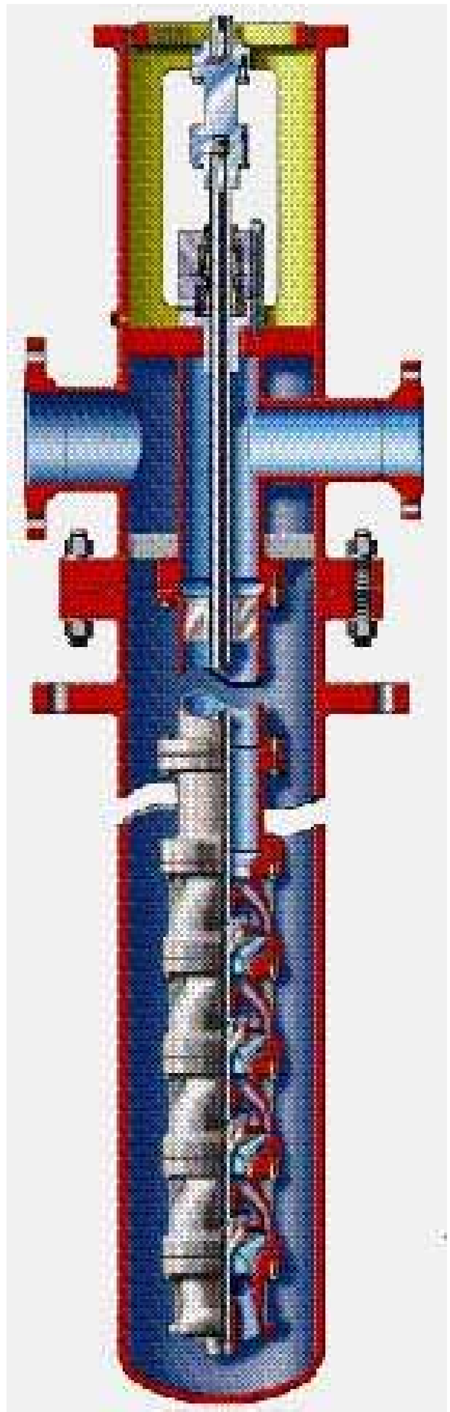


Figure 4,9 – 2 Pump Cross-section

4.9.6.4 Mechanical Seal

One mechanical seal is fitted where the drive shaft enters the pump head. The seal may be subject to discharge pressure, which can be high. When the pump stops, the seal is at suction pressure, which might be less than atmospheric.

For details of Mechanical Seals and related hazards see **Sections 5.3.3 & 5.3.4**.

4.9.6.5 Bearings

The pump shaft is supported by several radial bearings, on the drive shaft and between stages. These are all product lubricated, hence will be damaged by dry running. Shaft weight / pump thrust may be carried by a separate external oil-lubricated bearing mounted above the pump head, or by transfer to the thrust bearing in the motor. In this last case a rigid shaft coupling will be used.

For details of Bearings and related hazards see **Section 5.9**.

4.9.6.6 Support Systems

Baseplate

The caisson is normally bolted to the floor or other steelwork. The support is intended to take the weight of the pump and pipework but not to act as a rigid pipe anchor.

Lubrication System

Thrust bearing lubrication will be self contained. No external connection is involved, other than perhaps water cooling for larger models.

Seal Support System

Liquid support system is traditionally a pressure pot with thermosyphon cooling, containing a compatible clean fluid (e.g. light hydrocarbon oil).

Pump Recycle System

See **Section 4.6.6.6**

4.9.6.7 Control & Management Systems

See **Section 4.6.6.7**

If pumps are started remotely or automatically, the control system should check for adequate liquid flooding before the pump is started, and should monitor suction level & discharge pressure to check for proper operation.

4.9.7 INTEGRATION ASPECTS

4.9.7.1 Process System Design

The design of the suction and recycle pipework, vessels and valves should ensure self venting and minimal restrictions, to enable satisfactory operation on low NPSH duties. Short, large bore suction pipework is appropriate, with special attention paid to layout.

4.9.7.2 Mechanical Integrity

Most of the working parts are enclosed in the Caisson. However the shaft is long and relatively flexible, so a bearing failure could result in seal damage.

4.9.7.3 Coupling Alignment

The coupling alignment is dictated by build quality & spigots on housing sections. If a flexible coupling is fitted, this should suffice. If a rigid coupling is fitted, it would be sensible to do run-out checks at motor bearing and mechanical seal before re-starting after overhaul.

4.9.7.4 Condition Monitoring

Process suction level, suction & discharge pressures, seal support system pressures, are the most valuable parameters to monitor. Periodic vibration monitoring of pump head, and motor bearings, should also be of value. It is not practical to measure the vibration inside the cartridge.

4.9.7.5 Protective Systems

See **Section 4.6.7.5**

Loss of suction level, perhaps loss of discharge pressure, would be appropriate trips.

SECTION 4.10

CENTRIFUGAL PUMP – HIGH PRESSURE MULTI-STAGE BARREL TYPE

CONTENTS

This report section covers a High Pressure Multi -stage Centrifugal Process Pump. It is written with a water duty in mind. To avoid unnecessary duplication, generic remarks in **Sections 4.6** & **4.8** will not be repeated, but are referenced.

The target duty is high pressure water injection. The pump is very similar to the Barrel Casing pump except with even higher operating pressure. In contrast, the fluid being pumped is neither flammable nor toxic.

4.10.1 INTRODUCTION

- ***High Pressure Multi-stage Centrifugal Pumps are employed where the required head is too much for a single stage or standard multi-stage pump.***
- ***Barrel Casing Design gives particularly good containment and should always be chosen.***

High pressure multi-stage pumps can have up to 10 stages within the barrel casing.
They are very similar to more conventional multi-stage pumps, but have a stronger pressure containment. (See **Section 4.8**)
For Single Stage pumps of Barrel Casing Design, see also **Section 4.6**.

Ring Section and Horizontal Split Casing Pumps are available at less capital cost. They are easier to maintain but are far more vulnerable to leaks.

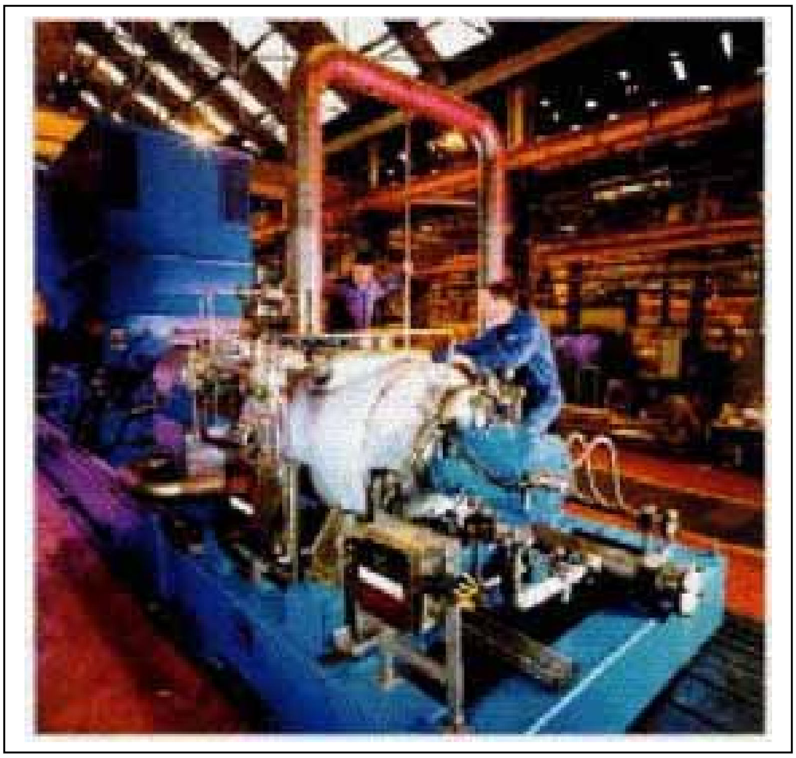


Figure 4,10 – 1 High Pressure Barrel Casing Pumpset

4.10.2 BACKGROUND & HISTORY

- ***High pressure multi-stage pumps were derived for boiler feed water duties.***
- ***They can handle low viscosity clean liquids.***

As steam boiler pressures rose, manufacturers developed ring-section multi-stage pumps with an increasing number of stages. These were vulnerable to leaks, particularly after maintenance, and barrel casing pumps should now be the norm.

Boiler feed water is hot, low viscosity and clean. Pumps derived from this technology are suitable for similar liquids. Abrasive solids, in particular, will cause severe wear.

4.10.3 HAZARD ASSESSMENT

- ***The hazards associated with a high pressure multi-stage pump differ only in degree from those associated with more normal pumps.***

4.10.3.1 Process Substance Containment Hazards

See **Sections 4.6.3.1 & 4.8.3.1**

In these pumps, discharge pressures can exceed 300 barg, even a pin-hole leak can give a dangerous fluid jet or atomised spray of considerable length.

Although high pressure water has no fire/ explosion risk, it is capable of causing severe/ fatal injuries to people. High pressure hot water (120 – 150 C) is particularly hazardous as a release flashes to create an opaque steam cloud. Entry into the cloud without a special protective suit and breathing apparatus is potentially fatal.

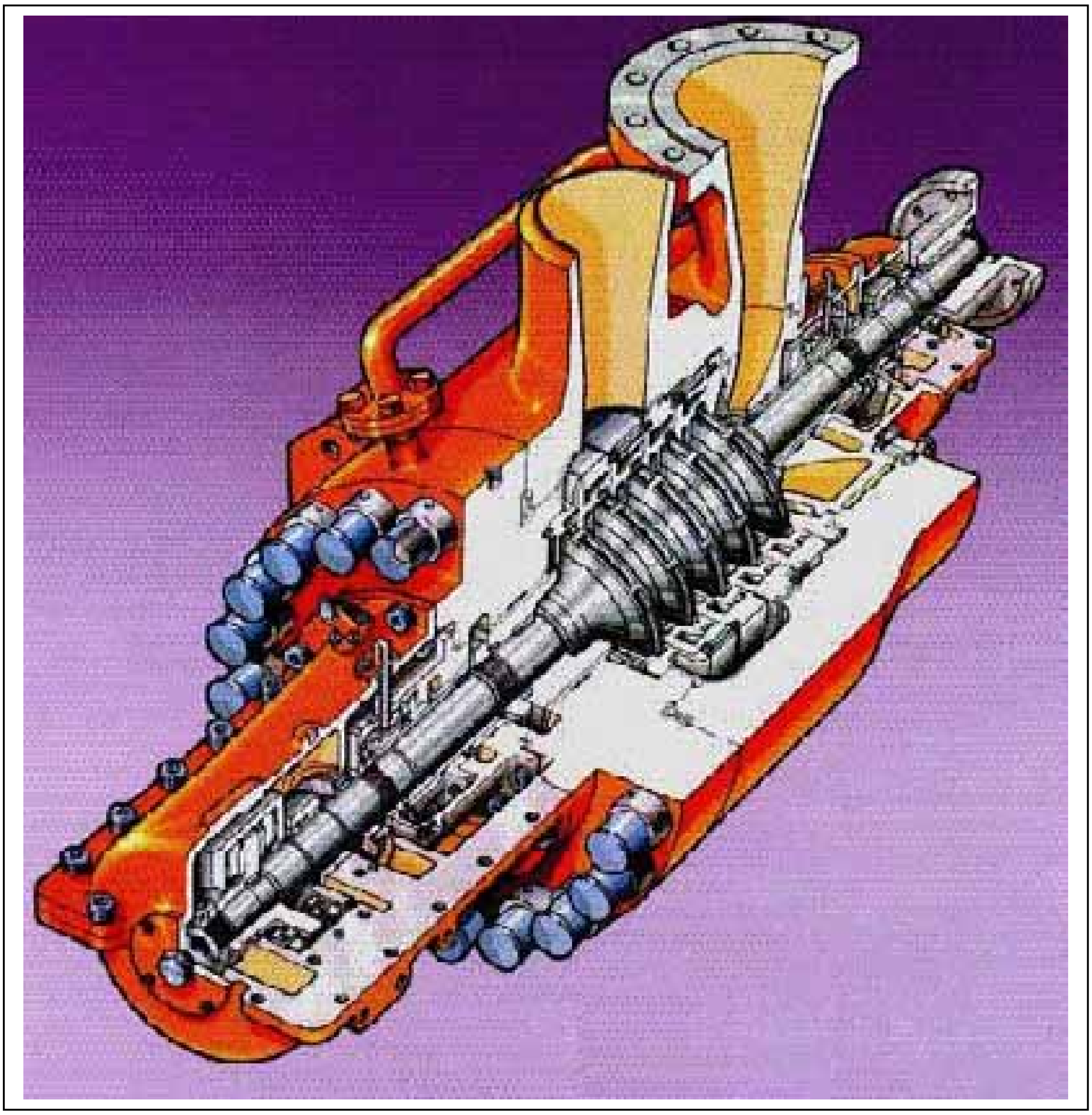


Figure 4,10 – 2 High Pressure Barrel Casing Pump Cutaway

4.10.3.2 Equipment Hazards

See **Sections 4.6.3.2 & 4.8.3.2**

Provided that all the pressure stages are in one casing, there are no external parts, except for delivery branch, at the high delivery pressure. It is quite practical to weld the discharge branch into the pipework, to minimise the leakage risk.

If the pressure rise is in two casings in series, the mechanical seals of the high stage are likely to be exposed to the delivery pressure of the low stage.

4.10.3.3 Operational / Consequential Hazards

See **Sections 4.6.3.3 and 4.8.3.3**

Very high pressure fluids, especially water, are highly erosive even though they do not contain solids. This often shows as damage to piping bends, valve seats and orifice plates, particularly in locations of high velocity / high pressure drop. Some form of inspection of the piping should therefore be in place to monitor this effect. The pump will not usually suffer form this damage as it is normally built of more resistant material than the pipework.

4.10.3.4 Maintenance / Access Hazards

See **Sections 4.6.3.4 and 4.8.3.4**

High pressure pumps are no different from other multi-stage pumps, except that jointing quality is even more critical.

4.10.4 OPERATING REQUIREMENTS

See Section 4.8.4

4.10.5 MAINTENANCE REQUIREMENTS

- ***High pressure multi-stage pumps are designed to be maintained by removal of the cartridge to a workshop, there is seldom the access or suitable conditions for in-situ work.***

See **Section 4.8.5**

4.10.6 HIGH PRESSURE MULTI-STAGE PUMP MAIN COMPONENTS

See **Section 4.8.6** and sub-sections.

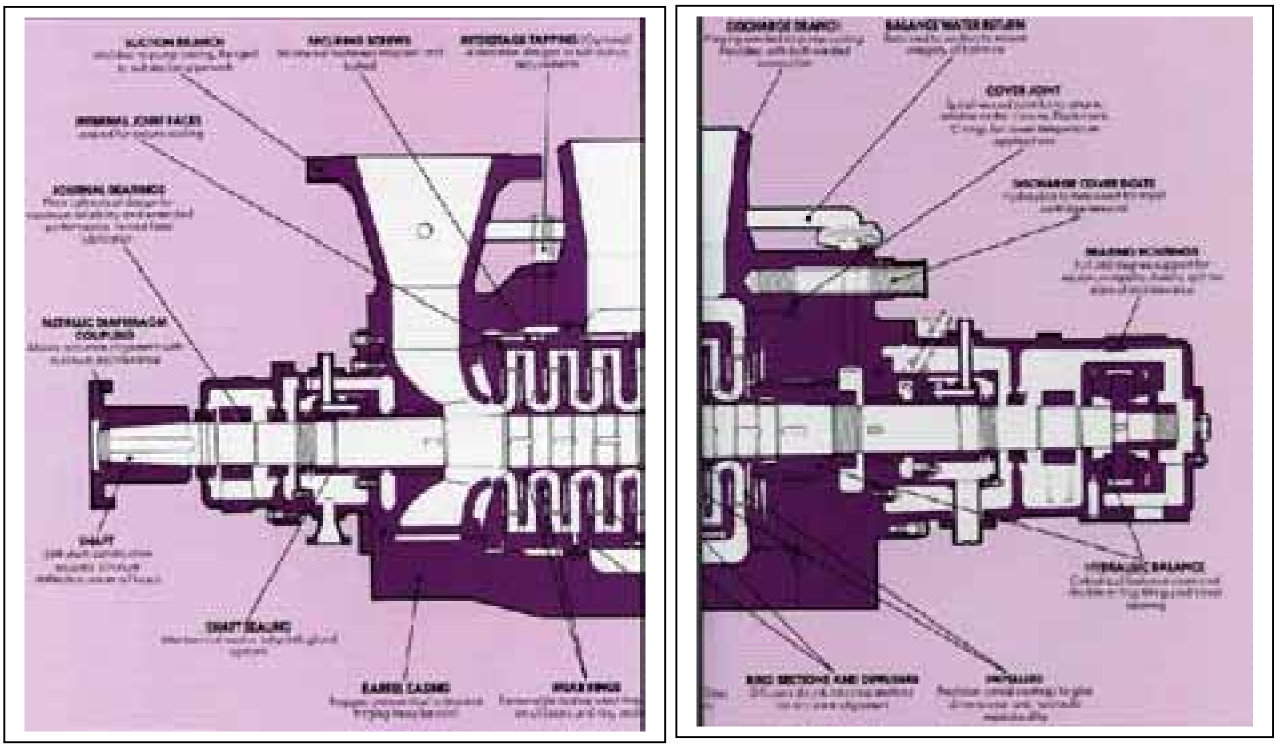


Figure 4,10 – 3 High Pressure Pump Cross Section

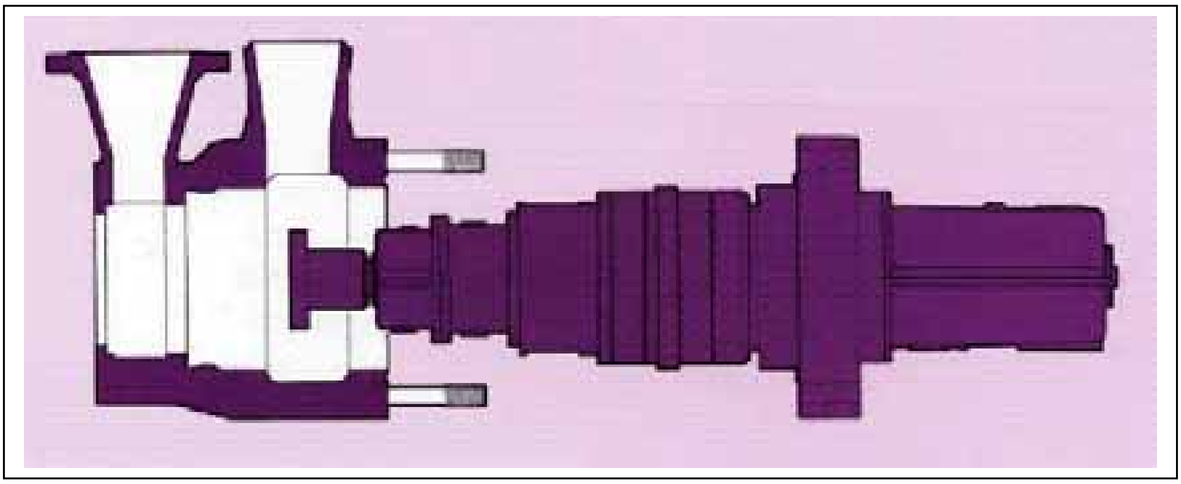


Figure 4,10 – 4 High Pressure Pump Cartridge Concept

4.10.7 INTEGRATION ASPECTS

4.10.7.1 Process Duties

High pressure multi-stage pumps tend to have a high NPSHr (See **Section 4.6 Appendix 1** for an explanation of NPSH), this often requires the installation of a suction booster pump. The booster would be a simple single stage pump of low NPSH design. High pressure pumps deliver to a fairly narrow pressure band, thus start-up is normally via a recycle line, with return to suction tank or manifold. The pressure breaking device on the recycle line will be special, to minimise wear. To reduce the risk of damaging back-flow through the pump, two non-return valves of different types may be fitted, or NRV linked to discharge trip valve. These valves do not shut off the recycle.

4.10.7.2 Mechanical Integrity

See **Section 4.8.7.2**

Additionally, the cartridge requires particular care in handling, to avoid damage to the high pressure stage seals, and to avoid bending the unit.

4.10.7.3 Alignment

See **Section 4.8.7.3**

4.10.7.4 Condition Monitoring

See **Section 4.8.7.4**

4.10.7.5 Protective Systems

See **Sections 4.6.7.5 and 4.8.7.5**

4.10.7.6 Bearings

See **Section 4.8.7.6**

SECTION 4.10

CENTRIFUGAL PUMP – HIGH PRESSURE MULTI-STAGE BARREL TYPE

CONTENTS

This report section covers a High Pressure Multi -stage Centrifugal Process Pump. It is written with a water duty in mind. To avoid unnecessary duplication, generic remarks in **Sections 4.6** & **4.8** will not be repeated, but are referenced.

The target duty is high pressure water injection. The pump is very similar to the Barrel Casing pump except with even higher operating pressure. In contrast, the fluid being pumped is neither flammable nor toxic.

4.10.1 INTRODUCTION

- ***High Pressure Multi-stage Centrifugal Pumps are employed where the required head is too much for a single stage or standard multi-stage pump.***
- ***Barrel Casing Design gives particularly good containment and should always be chosen.***

High pressure multi-stage pumps can have up to 10 stages within the barrel casing.
They are very similar to more conventional multi-stage pumps, but have a stronger pressure containment. (See **Section 4.8**)
For Single Stage pumps of Barrel Casing Design, see also **Section 4.6**.

Ring Section and Horizontal Split Casing Pumps are available at less capital cost. They are easier to maintain but are far more vulnerable to leaks.

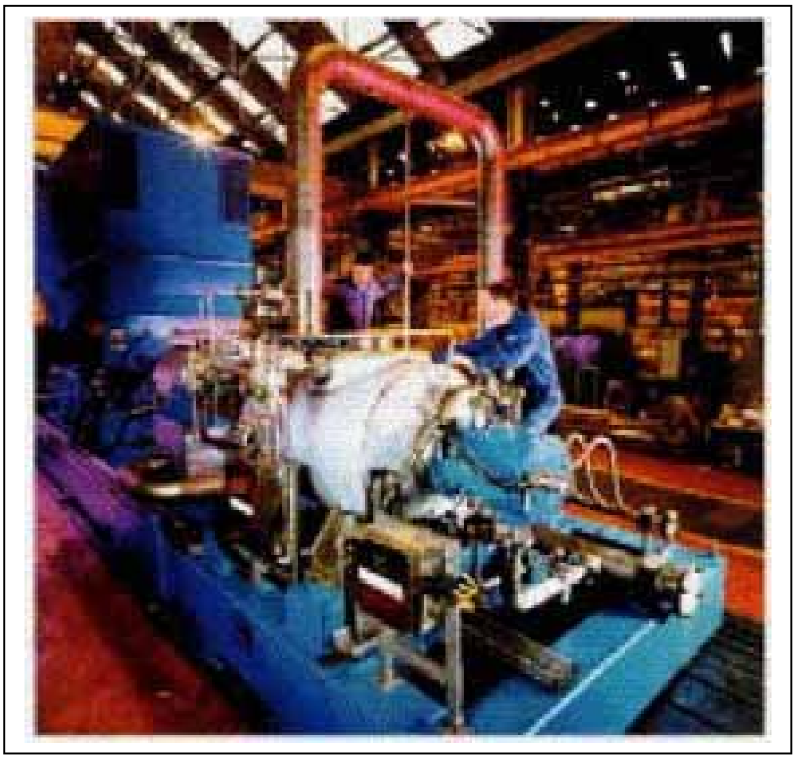


Figure 4,10 – 1 High Pressure Barrel Casing Pumpset

4.10.2 BACKGROUND & HISTORY

- ***High pressure multi-stage pumps were derived for boiler feed water duties.***
- ***They can handle low viscosity clean liquids.***

As steam boiler pressures rose, manufacturers developed ring-section multi-stage pumps with an increasing number of stages. These were vulnerable to leaks, particularly after maintenance, and barrel casing pumps should now be the norm.

Boiler feed water is hot, low viscosity and clean. Pumps derived from this technology are suitable for similar liquids. Abrasive solids, in particular, will cause severe wear.

4.10.3 HAZARD ASSESSMENT

- ***The hazards associated with a high pressure multi-stage pump differ only in degree from those associated with more normal pumps.***

4.10.3.1 Process Substance Containment Hazards

See **Sections 4.6.3.1 & 4.8.3.1**

In these pumps, discharge pressures can exceed 300 barg, even a pin-hole leak can give a dangerous fluid jet or atomised spray of considerable length.

Although high pressure water has no fire/ explosion risk, it is capable of causing severe/ fatal injuries to people. High pressure hot water (120 – 150 C) is particularly hazardous as a release flashes to create an opaque steam cloud. Entry into the cloud without a special protective suit and breathing apparatus is potentially fatal.

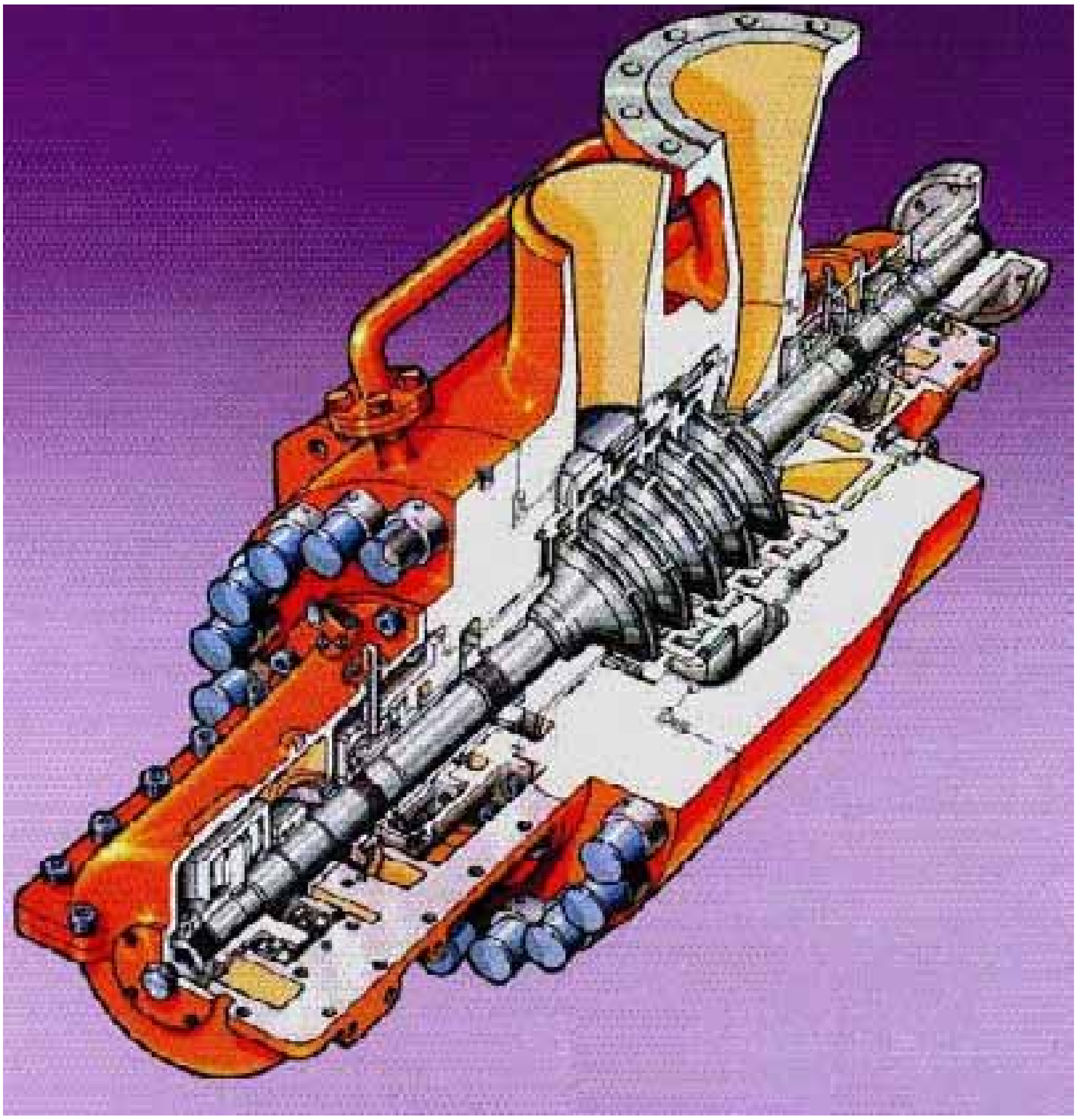


Figure 4,10 – 2 High Pressure Barrel Casing Pump Cutaway

4.10.3.2 Equipment Hazards

See **Sections 4.6.3.2 & 4.8.3.2**

Provided that all the pressure stages are in one casing, there are no external parts, except for delivery branch, at the high delivery pressure. It is quite practical to weld the discharge branch into the pipework, to minimise the leakage risk.

If the pressure rise is in two casings in series, the mechanical seals of the high stage are likely to be exposed to the delivery pressure of the low stage.

4.10.3.3 Operational / Consequential Hazards

See **Sections 4.6.3.3 and 4.8.3.3**

Very high pressure fluids, especially water, are highly erosive even though they do not contain solids. This often shows as damage to piping bends, valve seats and orifice plates, particularly in locations of high velocity / high pressure drop. Some form of inspection of the piping should therefore be in place to monitor this effect. The pump will not usually suffer form this damage as it is normally built of more resistant material than the pipework.

4.10.3.4 Maintenance / Access Hazards

See **Sections 4.6.3.4 and 4.8.3.4**

High pressure pumps are no different from other multi-stage pumps, except that jointing quality is even more critical.

4.10.4 OPERATING REQUIREMENTS

See Section 4.8.4

4.10.5 MAINTENANCE REQUIREMENTS

- ***High pressure multi-stage pumps are designed to be maintained by removal of the cartridge to a workshop, there is seldom the access or suitable conditions for in-situ work.***

See **Section 4.8.5**

4.10.6 HIGH PRESSURE MULTI-STAGE PUMP MAIN COMPONENTS

See **Section 4.8.6** and sub-sections.

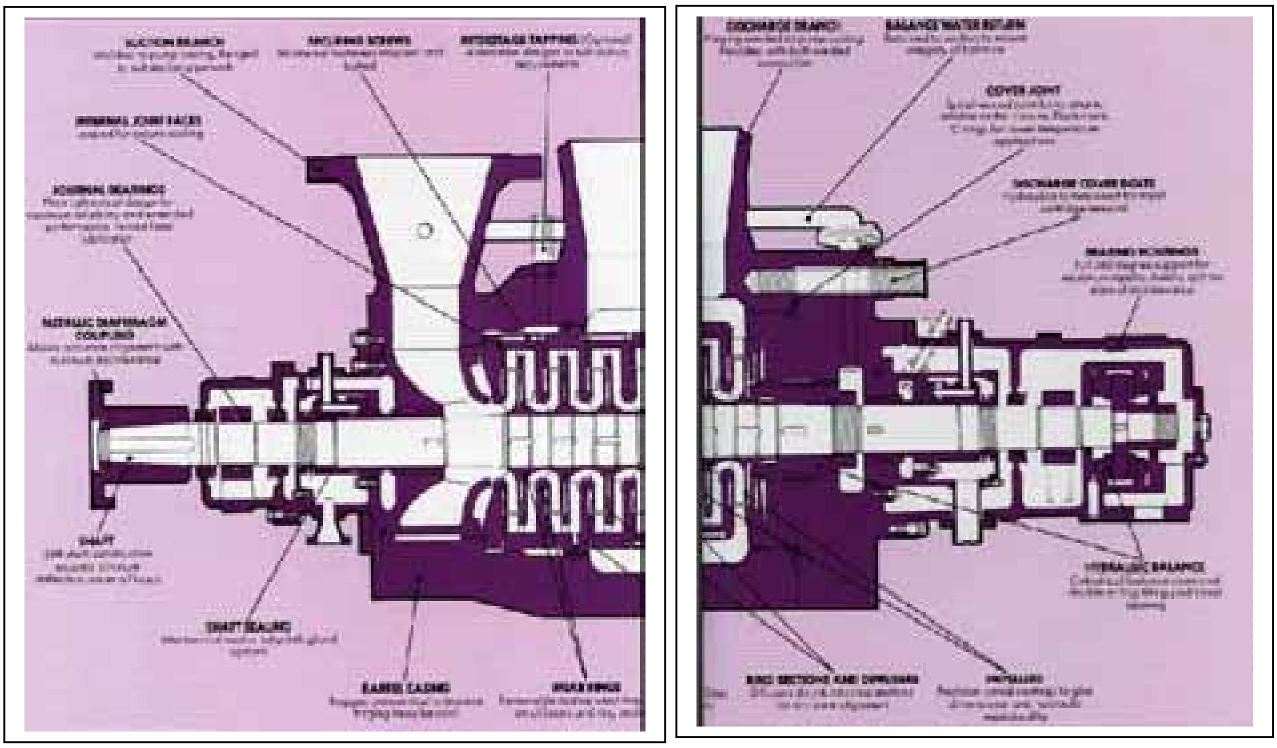


Figure 4,10 – 3 High Pressure Pump Cross Section

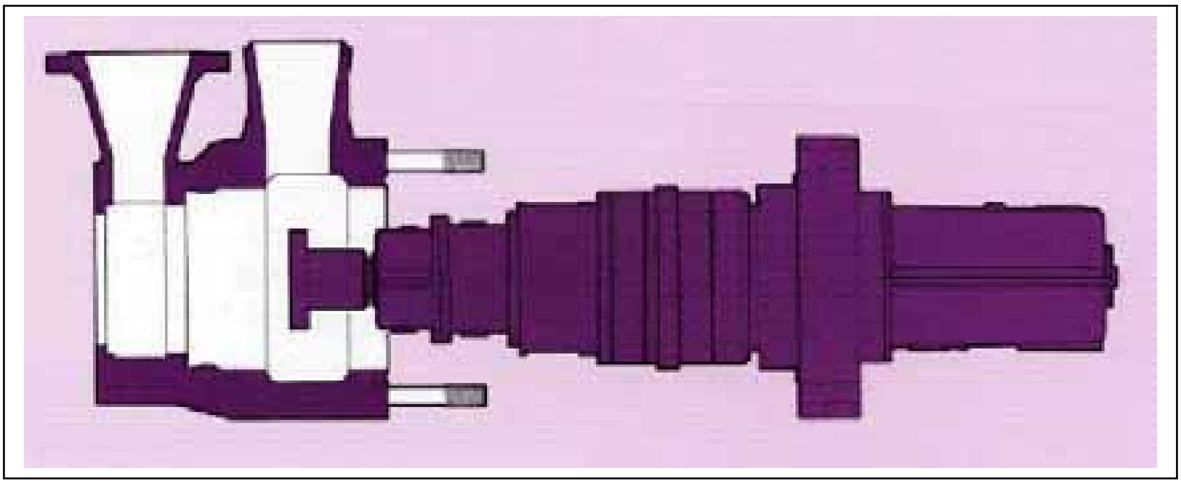


Figure 4,10 – 4 High Pressure Pump Cartridge Concept

4.10.7 INTEGRATION ASPECTS

4.10.7.1 Process Duties

High pressure multi-stage pumps tend to have a high NPSHr (See **Section 4.6 Appendix 1** for an explanation of NPSH), this often requires the installation of a suction booster pump. The booster would be a simple single stage pump of low NPSH design. High pressure pumps deliver to a fairly narrow pressure band, thus start-up is normally via a recycle line, with return to suction tank or manifold. The pressure breaking device on the recycle line will be special, to minimise wear. To reduce the risk of damaging back-flow through the pump, two non-return valves of different types may be fitted, or NRV linked to discharge trip valve. These valves do not shut off the recycle.

4.10.7.2 Mechanical Integrity

See **Section 4.8.7.2**

Additionally, the cartridge requires particular care in handling, to avoid damage to the high pressure stage seals, and to avoid bending the unit.

4.10.7.3 Alignment

See **Section 4.8.7.3**

4.10.7.4 Condition Monitoring

See **Section 4.8.7.4**

4.10.7.5 Protective Systems

See **Sections 4.6.7.5 and 4.8.7.5**

4.10.7.6 Bearings

See **Section 4.8.7.6**

SECTION 4.11

CENTRIFUGAL PUMP – VERTICAL LONG-SHAFT OR SUBMERSIBLE DRIVER TYPE

CONTENTS

This report section covers a Vertical Centrifugal Utility Pump operating in a submerged location. To avoid unnecessary duplication, generic remarks in **Section 4.6** will not be repeated, but are referenced.

The target duty is a Seawater Lift Pump, either Diesel Engine driven for Fire Water duty, or powered by a submersible driver for Utility duties. Due to the location of the pump, prime hazards are from loss of service, and maintenance activities.

4.11.1 INTRODUCTION

- ***Vertical Long-Shaft / Submersible Driver Centrifugal Pumps are employed where it is necessary to install the pump in the source liquid reservoir.***

Vertical Long-Shaft Centrifugal Pumps are installed where it is necessary to install the pump below sea level, with the driver on the platform. They comprise a multi-stage vertical pump fitted into a guide tube or conductor, with the pump below sea level. Drive is by a long vertical shaft from an appropriate driver at platform level. This arrangement is almost exclusively used for diesel driven fire pumps, although it can be used to recover e.g. diesel fuel stored in a platform leg.

Submersible Driver Pumps are similar but are normally driven by a close-coupled electric motor. The complete pump and motor assembly is hung in a conductor tube, supported by the discharge pipe. One variant covered employs a close-coupled hydraulic motor, powered by a hydraulic power-pack at platform level.

4.11.2 BACKGROUND & HISTORY

- ***Vertical multi-stage pumps were derived to pump water from wells.***

- ***Original designs were shaft driven. Fully submersible motor driven units have been developed.***

Historically, vertical multi-stage pumps were developed to lift water from wells and boreholes, and to drain mines. Suction is at the bottom, drive shaft and discharge at the top. The drive shaft (which may be long) is connected to an engine or other driver.

For water pumping from an open reservoir, the maximum practical suction lift is about 6m. For lifts beyond that, the pump (or at least a suction booster pump) must be located within 6m, it is then usually simpler to fully submerge the pump and avoid any suction lift problems.

A simple solution is to create a vertical guide tube, with a flanged top, or with a steel structure above. This installation acts as a location & mounting for the pump. Commonly the pump suction is located 2 – 3 m below minimum liquid level. For sea-water lift duties, allowance must be made for extreme tidal and wave movements, putting the pump anything up to 15 m below water.

With platform topsides being located above maximum wave height, a very long drive shaft is required. Designs involving electric or hydraulic drive avoid this long shaft, and can permit horizontal displacement and relative motion between pump and driver. Close-coupled drivers are normally mounted on the bottom (suction end) of the pump so as not to block the delivery pipe, and to take advantage of cooling from the open water below.

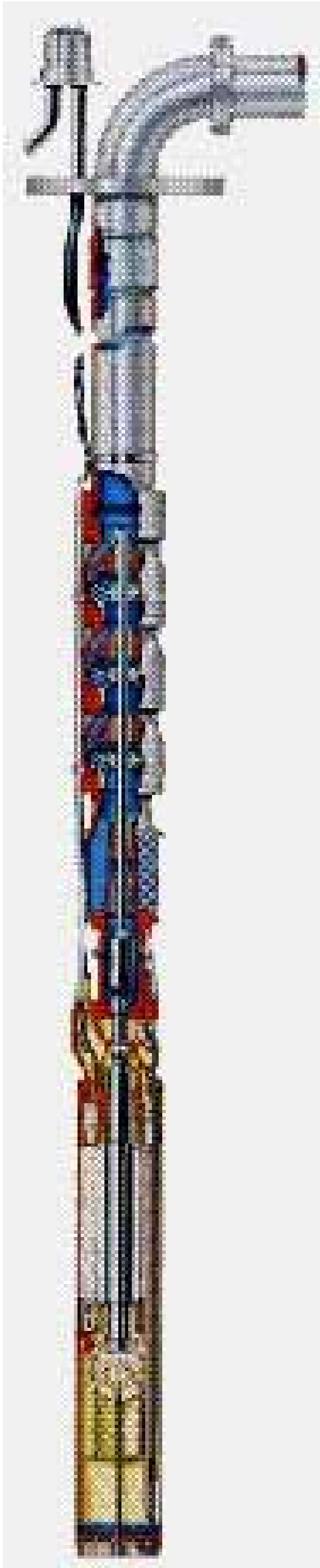


Figure 4,11 – 1

Submersible Motor Seawater Lift Pumpset

4.11.3 HAZARD ASSESSMENT

- ***There is little or no direct hazard from a pump failure.***
- ***Divers may be at risk from the intake flow of a running pump.***
- ***The greatest potential hazard to the installation is from loss of the pumped service.***

Figure 4,11 – 2 Diesel Driven Fire Water Pumpset (top section)

4.11.3.1 Process Substance Containment Hazards

As the complete pump is submerged, and the duty is normally sea water (although this type of pump could be used for lifting oil from deep storages) there is no direct hazard from a pump failure. Failure of pipework on the platform could cause a hazard, as with any other pipework failure.

Fire pumps are normally physically well separated from each other for fire safety reasons, a fire affecting one pump should not affect another. As divers working close to the pump suction could be at risk of being sucked in (depending on screening / shielding arrangements) it is normal to

suspend pumping when diving is in progress local to the pump. This suspension has to be managed within the Permit To Work system as it reduces the fire-fighting capability of the installation.

4.11.3.2 Equipment Hazards

See **Section 4.6.3.2** for generic pump hazards.

Most of the moving parts are contained within the pump casing which is itself contained within the conductor. The drive shaft (if topside driven) runs inside the discharge pipe, which is also inside the conductor.

The topside drive may be by an electric motor, or by a (diesel) engine. In the latter case a right angle drive gearbox is required. For these hazards see within **Section 3.6 – Diesel Engine**.

The greatest mechanical hazard is probably a mechanical collapse or dropping of pump assembly during a crane lift or other similar maintenance. People working in the area, and vessels below, would be at risk.

For details of Bearings, Seals, Shaft Couplings and related hazards see **Section 5 – Auxiliary Systems & Equipment.**

4.11.3.3 Operational / Consequential Hazards

See **Section 4.6.3.3**

Additionally, such pumps are constantly flooded, having no suction isolation valve. On pump start a large air column will be displaced before liquid is available. The process of air release must be controlled to avoid hydraulic shock. As it is not possible to inspect this type of pump in situ, the only way to know that the pump is operational, is to carry out periodic test runs.

4.11.3.4 Maintenance / Access Hazards

See **Section 4.6.3.4**

The entire pump (and driver if attached) must be lifted out for any maintenance work. This typically involves breaking the discharge pipe (and drive shaft as appropriate) at successive joints, and pulling the pump up through the conductor. More modern platforms may allow the platform crane to pull out long sections by using a series of deck hatches.

Grilles must be provided so that any objects (e.g. fish), that cannot pass through the pump, are not allowed to enter the bottom of the conductor. The grilles must have a large enough area, and large enough openings, not to be blocked by marine growth. The grilles should also be strong enough to prevent a dropped pump or parts from falling through.

4.11.4 OPERATING REQUIREMENTS

Vertical long shaft pumps on fire duty must run on demand, maintaining the pressure in the fire main. They are routinely test run, and must achieve pressure & flow on test. In emergency, a few hours' operation only is required, after which the condition of the pumps is immaterial.

Submersible driver pumps are utility pumps so tend to run continuously on a steady load. Several pumps may run in parallel on a duty, according to demand. As the pump suction is constantly flooded, and there are no support systems, operation is very simple.

Due to the location of the pump, operators are totally reliant on good process instruments, particularly those measuring pressures and flow.

Features

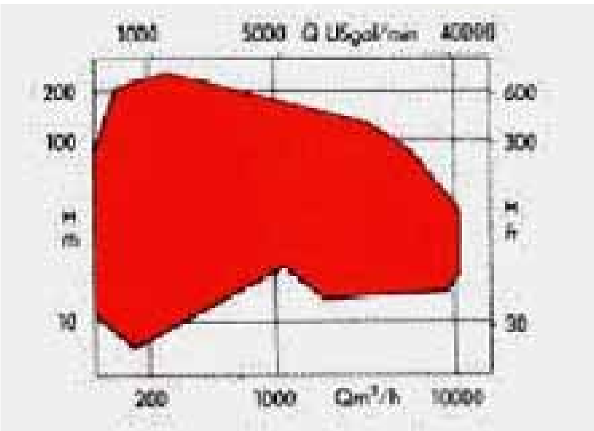
Minimum surface installation area.
High pump efficiency for energy conservation.
Matched pump and driver.
Reliability.
Low maintenance costs.
Stable head/ quantity curve.
Versatile drive arrangements and construction features.
Pumps can be driven by a vertical electric motor mounted on pump headpiece if required.
Designed to NFPA 20 specification for firewater applications.

Applications

Fire and sea water lift duties for rigs and platforms.
Cooling water supply for offshore duties.
Oil transfer, boosting and cavern storage extraction.

Duties

Heads up to 250 m (820 ft)
Flows up to 10800 m3/hour
(47500 US gal/min)



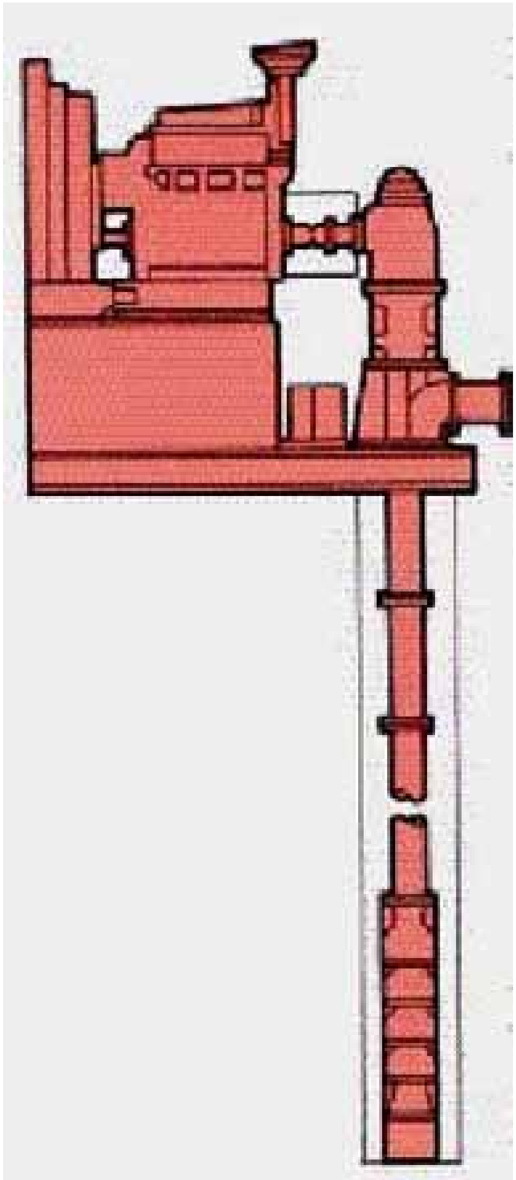
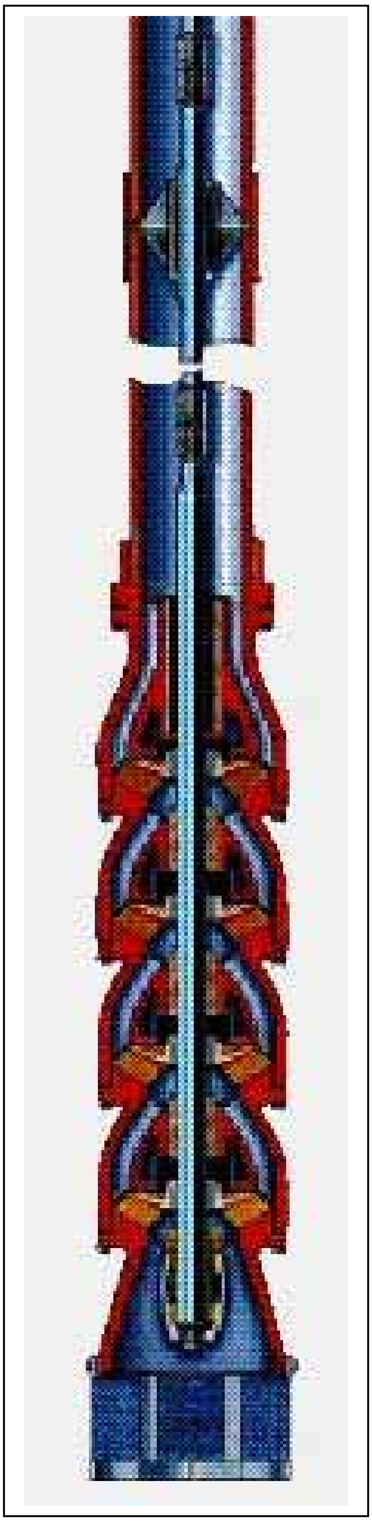


Figure 4,11 – 3

Vendor Application Data for Fire Pump

4.11.5 MAINTENANCE REQUIREMENTS

- ***Vertical submerged pumps can only be maintained by removal of the complete pump unit to workshop conditions or other suitable area.***



The pump assembly must be removed to workshop conditions or a suitable open area for any maintenance. The only site work thus required is inspection of the condition of the pump support tube, drive shaft, driver & supports. As the entire assembly relies on spigot fits, provided that these have been correctly made, no alignment checks are required or possible.

For long-shaft pumps the drive connection must first be broken, and motor / gearbox / support bearing, as appropriate, moved out of the way. The discharge pipe must then be unbolted in sections, dismantling the drive shaft or separating the drive cables, as appropriate. The complete pump assembly will then be lifted out, this is long and thus requires headroom. On submersible driver units, the driver can now be removed. The pump will have to be laid down on scaffolding or a special frame, to avoid damage through bending.

Leak testing and performance testing can only be done with the pump fully assembled, or with the pump built up in a test casing. Electrical cables or hydraulic hoses should be tested (insulation quality, continuity, kinks, connection integrity, fraying, leakage, as appropriate) both before and after re-installation of the pump.

4.11.5.1 Corrosion

See **Section 4.6.5.1**

All pump components are in contact with the fluid being pumped, and must therefore be compatible. An internal failure would not pose a safety hazard.

The conductor tube and pump support system are subject to wave and tidal effects, this is an aggressive environment.

Figure 4,11 – 4 Long-shaft Pump Unit Cross-section

4.11.6 VERTICAL SUBMERGED PUMP MAIN COMPONENTS

4.11.6.1 Pump Guide Tube or Conductor

This is a vertical fabricated steel tube, welded to the substructure. It provides installation guidance and wave protection for the submerged pump. The conductor does not carry the weight of the pump, but must be strong enough at the bottom to retain a dropped pump, for subsequent retrieval. The pump discharge pipe and drive shaft (or electric / hydraulic flexible supply lines) run inside the conductor and are protected from wave impact.

4.11.6.2 Pump Unit

The pump unit is a multi-stage vertical pump built up of bolted stator segments with impellers between. The lower end comprises a bellmouth suction. The radial and thrust bearings are simple product lubricated items.

Long shaft driven pumps have a drive shaft attached to the discharge (top) end. Submersible driver pumps have an electric motor or hydraulic motor close-coupled to the lower end.

4.11.6.3 Discharge Pipe

The discharge pipe is connected to the top of the pump unit. For long-shaft drive designs, the drive shaft runs inside the discharge pipe, with periodic shaft bearings.

For submersible drive units, the power supply cables or tubes run up the outside of the discharge pipe. These cables or tubes should be carefully attached, especially where they pass over the pipe joints. This is to ensure that they are not damaged during installation, or by wave action.

Spiders may be provided to separate the discharge tube from the conductor.

4.11.6.4 Discharge Bend and Mechanical Seal

Located at the top of the discharge pipe, this supports the weight of the pump and discharge pipe. It is bolted to the platform deck and flanged to the distribution pipework, in such a way that it can be unbolted and lifted out with the discharge pipe and pump still attached. On long-shaft driven pumps, the drive shaft passes through the discharge bend, sealed by a simple mechanical seal. As this seal is subject to pump discharge pressure, it may be fitted with a packed gland or external throttle bush.

4.11.6.5 Control & Management Systems

See **Section 4.6.6.7**

Electrically driven Pump (Submersible)

Features

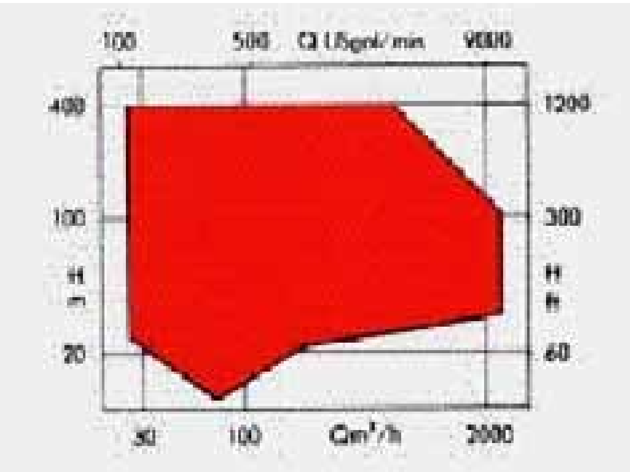
Voltages up to 6.6 kV. Low capital cost.
Minimum surface installation area. Easily and rapidly installed.
Quiet running. Safe against flooding.
High pump efficiency for energy conservation.
Glandless pump construction.
Can be installed at any angle between vertical and horizontal, provided that the pump end is not below the motor end. The cable has no joints between the motor and the surface.
Can be supplied with a dedicated diesel generator designed to NFPA 20 specifications. Diesel driver can be located remote from pump in non-hazardous area, if required.

Applications

Fire and sea water lift duties for rigs and platforms. Sea bed jetting.
Oil storage cavern extraction.
Cooling water supply for offshore duties.
Warm well water duties.

Duties

Heads up to 400 m (1315 ft)
Flows up to 2500 m3/hour (11000 US gal/min)



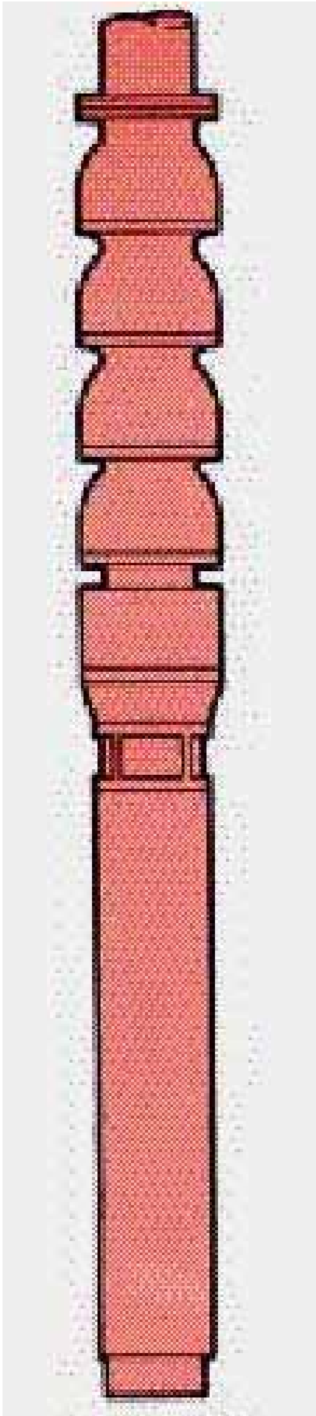


Figure 4,11 – 5 Vendor Application Data

4.11.7 INTEGRATION ASPECTS

4.11.7.1 Process System Design

Several pumps normally connect to a single manifold, to allow selection of pumps according to system load / operating restrictions. Control valves / isolation valves/ non return valves are required to manage flows and system safety. Venting of discharge lines is important during pump start. Pumps are self draining, and will counter-rotate as the water drains back to sea level, preventing immediate re-start.

4.11.7.2 Mechanical Integrity

All of the working parts are enclosed / hidden. These pumps are very simple so are reliable, but bearings will suffer progressive wear, particularly if the water contains sand / mud particles.

4.11.7.3 Drive Shaft Alignment

The drive shaft alignment is dictated by build quality & spigots on housing sections. Run-out checks will be required as assemblies are mated.

4.11.7.4 Condition Monitoring

Vibration monitoring may be possible as a check on pump health. The location is very difficult so twin sensors should be installed.

On stand-by / emergency systems the only effective proof of availability is a periodic loaded run test for a reasonable period e.g. 1 hour.

4.11.7.5 Protective Systems

See **Section 4.6.7.5**

Loss of discharge pressure, possibly high vibration on 2 sensors, would be appropriate trips.

For submersible electric motors, insulation resistance monitors are often used, “Bender” and “Vigiohm” being common systems. These give alarm annunciation then trip the drive at appropriate pre-set levels.

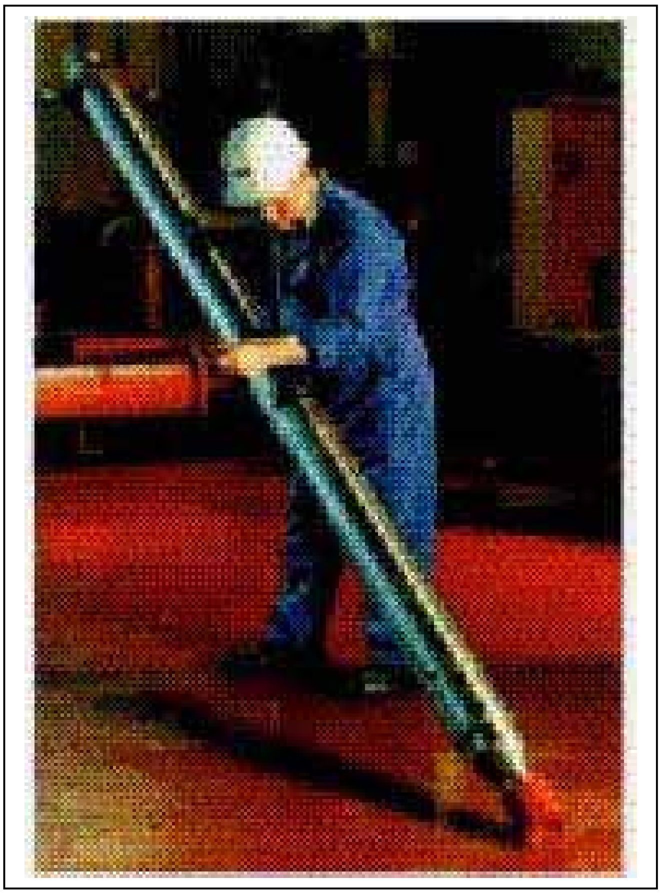


Figure 4,11 – 6 Hydraulically Driven Downhole Pumpset

SECTION 4.12

CENTRIFUGAL PUMP – VERTICAL HIGH SPEED TYPE

CONTENTS

This report section covers a High Speed Vertical Centrifugal Process Pump. To avoid unnecessary duplication, generic remarks in **Section 4.6** will not be repeated, but are referenced.

Target duty for vertical high speed pumps is the handling of Natural Gas Liquids (NGLs), raising the issues of handling highly volatile and flammable substances.

4.12.1 INTRODUCTION

- ***High Speed Centrifugal Pumps are employed where the required head is too much for a standard pump, but the flow is too low for a Barrel Casing Pump.***
- ***High Speed drive is achieved by an integral gearbox.***
- ***Developments in inverter driven high speed motors may avoid the need for the gearbox on recent installations.***

High Speed Centrifugal Pumps are selected for moderate/ low flow, high head duties on clean fluids. They comprise a single stage vertical inline pump driven by an integral gearbox. The motor is mounted on a stool above the pump. They are typically used for returning condensed hydrocarbons to the process.

The pumps are very similar to Vertical In-line Pumps to API 610, but have specialist internals and a special radial impeller design.

4.12.2 BACKGROUND & HISTORY

- ***Vertical in-line pumps were developed for marine and petrochemical applications, where space is at a premium.***
- ***The High Speed pump is an extension of this design, for higher head applications.***

Standard vertical in-line pumps use the same hydraulic components as horizontal pumps, but casing and bearing housings are quite different to suit the different mounting requirements. Smaller sizes can be mounted in pipework without a baseplate, and may use an extended motor shaft to support the impeller, eliminating the separate pump bearings. The mechanical seal arrangement is similar. The size and weight are reduced, the footprint is very much less than for a horizontal pump. This is of great benefit in marine and some petrochemical applications.

High Speed pumps were developed for American Aerospace applications. A special light-weight open radial impeller is fitted to a very slim high speed shaft, typically running 8000 – 15000 rev/min. This shaft is driven by an integral gearbox. A conventional electric motor drives the gearbox.

Pumps are now available running at 7200 rev/min., using an integral high speed inverter driven motor. The integral motor eliminates the need for mechanical seals.

4.12.3 HAZARD ASSESSMENT

- ***The hazards posed by High Speed pumps relate primarily to the process fluid, although gearbox fires are possible.***
- ***The machines are noisy but should not be lagged. Hence there is a noise hazard.***
- ***Gearboxes are aluminium, failure within the gearbox can lead to catastrophic disintegration of the gearbox. This is likely to cause severe damage to the seal.***

4.12.3.1 Process Substance Containment Hazards

See **Section 4.6.3.1** for generic information.

Additionally, as discharge pressures can easily exceed 100 barg, even a pin-hole leak can give a dangerous fluid jet or atomised spray of considerable length.

High speed and high pressure generation requires that pumps must not operate against closed isolation valves.

LMV/BMP Series	
Flows to:	1100 gpm
	250 m3/hr
Heads to:	6300 ft.
	1921 m
Maximum HP:	400 hp
	315 kW
Speed (RPM):	Variable depending on customer requirements
Max. Case Working Presssure:	2160 psig
	152 barg
Max. Suction Pressure:	1000 psig
	70 barg
Temperature Range:	-200° to 650° F
	-130° to 340° C

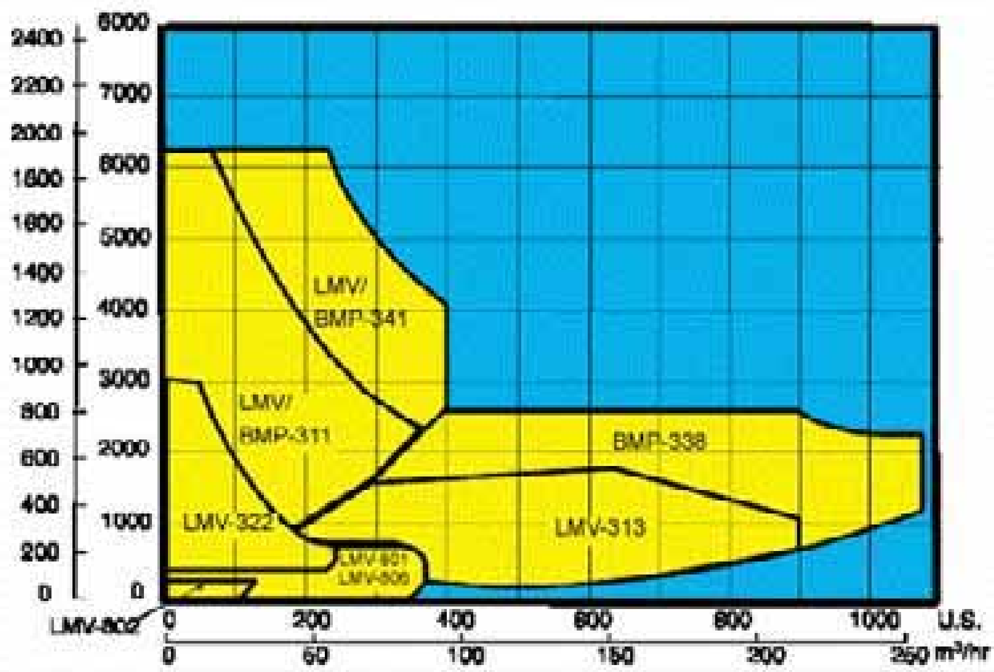


Figure 4,12 – 1 Vendor Application Data

4.12.3.2 Equipment Hazards

See **Section 4.6.3.2** for generic information.

High speed vertical pumps have a massive one-piece cast housing with a matching rear cover / gearbox mount. They are robust in containment terms although the gearbox drive is quite delicate. Drive failures can disrupt the mechanical seal.

The speed increasing gearbox is of aluminium construction, the special lubricating oil requires filtration and, usually, cooling. The gearbox is very noisy, but to aid cooling and reduce the risk of oil fires, it is not good practice to lag these units.

The conventional electric motor is flange mounted on top of a gearbox adapter, which encloses the flexible coupling. On the larger sizes, this makes the assembly very tall and top heavy. Due care is required in maintenance.

Gearbox lubrication is critical – low oil pressure trips are advised to avoid catastrophic failure – early machines with integral oil pumps required to be jog started to get to permissive oil pressure.

The gearbox casing is of cast aluminium, a significant internal failure, or fire, can cause catastrophic of the gearbox casing. This will not in itself cause major damage to the pump casing but the seal is likely to be severely damaged.

For details of Bearings, Seals, Shaft Couplings and related hazards see **Section 5** – Auxiliary Systems & Equipment.

Choice of bearings within gear box is highly sensitive due to loading – substitution away from OEM recommendations is not advisable. Any work on the gearbox should be done by specialists in clean workshop conditions.

High shaft loading requires high strength steel for pump shaft – to cope with corrosive environment shaft is sleeved with particular maintenance processes to ensure process fluid does not contact shaft – in extreme cases shaft has been gold plated.

4.12.3.3 Operational / Consequential Hazards

See **Section 4.6.3.3** for generic information.

The only operational limitation with these pumps is the relatively narrow operating flow range. This is normally dealt with by having a fixed, or flow controlled, recycle according to the required duty.

While it is possible to throttle on the discharge valve, on a high head pump this is likely to damage the valve over time, tight closure will then not be possible. Similarly the recycle can only be throttled using a special valve, to minimise wear. Fixed recycle flow may be controlled by a special wear-resistant orifice plate unit.

4.12.3.4 Maintenance / Access Hazards

See **Section 4.6.3.4** for generic information.

Maintenance can be done very simply with these pumps, as the motor is easily removed. The Back Pull Out / Gearbox unit may be removed from the casing, although with smaller units it may be simpler to remove the complete pump. The complete pump is easier to test, and to protect for storage or shipping. Good lifting facilities are required.

Gearbox oil filter and oil cooler are serviced in situ. Small fittings are a potential source of lubricating oil leaks.

4.12.4 OPERATING REQUIREMENTS

As high speed pumps have a high discharge head, mal-operation can cause pressure surges/ liquid hammer, particularly in long discharge lines.

Liquid hammer is most likely to be caused when filling / pressurising a line. Complex pipework should be allowed to fill slowly under low pressure, venting off air / gas from high points (to flare if flammable gas is involved). Long pipelines may have to be liquid filled by pigging, to push out air pockets at low pressure.

4.12.5 MAINTENANCE REQUIREMENTS

- ***Vertical in-line pumps (standard and high speed types) are designed to be maintained by removal of the Back Pull Out unit to a workshop, there is seldom the access or suitable conditions for in-situ work.***

It is assumed that the complete pump, or the Back Pull Out unit, will be removed to workshop conditions for any maintenance. The only site work thus required is inspection of the condition of the pump casing and ancillaries, e.g. seal support systems, gearbox oil filter, oil cooler, bearing housing. As the entire assembly relies on spigot fits, provided that these have been correctly made, no alignment checks are required or are possible.

The shaft mechanical seal is normally of cartridge design and is accessed by removing the impeller. The gearbox need not be disturbed. Lubricating oil must be removed before opening the gearbox.

Leak testing and performance testing can only be done with the pump fully assembled, or with the pump built up in a test casing.

It is important on rebuild that seal support systems and instruments are put back in working order, filled with fluids as required, and correct valves opened / closed.

4.12.5.1 Internal Corrosion

See **Section 4.6.5.1** for generic information.

High speed pumps have narrow clearances and a finely balanced rotor. Product contact materials must be selected for corrosion resistance.

Figure 4,12 – 2 Vertical High Speed Pump

4.12.6 HIGH SPEED CENTRIFUGAL PUMP MAIN COMPONENTS

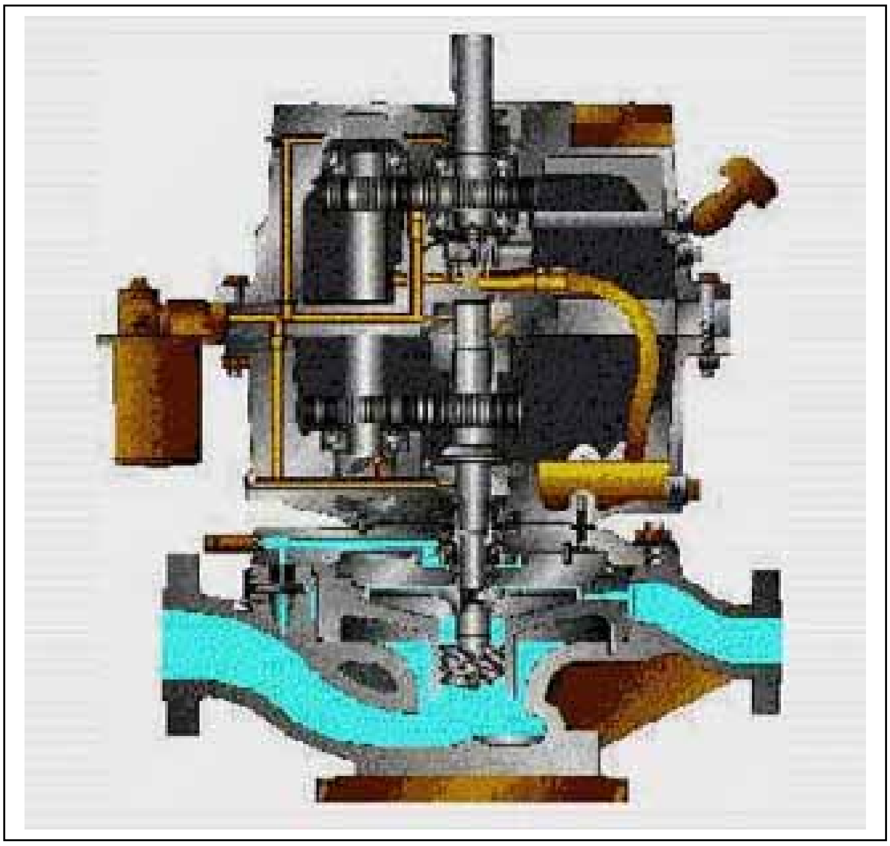


Figure 4,12 – 3 Vertical High Speed Pump Cross Section

4.12.6.1 Pump Casing

This is a single piece casting with flanged suction and delivery branches. Carbon steel is the norm for hydrocarbon service although stainless steels and exotic materials may be required for aggressive duties. Casings are very thick and gross failure in service is almost unknown. The only realistic leakage path is across joint faces, particularly if these have been dented or scored during maintenance. The complex shape of the suction and delivery branches makes internal inspection difficult. Some models have an in-built centrifugal separator to remove solids from the internal seal flush. This will not apply to petrochemicals applications, these will normally be fitted with a double mechanical seal.

4.12.6.2 Back Plate

The back plate is cast of the same material as the casing. It has a spigot fit and a fully retained casing gasket. It has an internal recess for the mechanical seal cartridge, and there are two access holes for seal service pipes. These screw into the seal cartridge, not the casing. The screw fit is unavoidable, posing some leakage risk. The fluid that can leak at this point should be the seal service fluid only.

The rear of the back plate has mounting ribs for the gearbox.

4.12.6.3 Impeller and Diffuser

The single impeller is of special "Barske" radial open design. It is normal for these pumps to be fitted with a screw-like suction inducer. This screws on the end of the pump shaft, retaining the impeller. For this reason, the pump should never be run backwards.

4.12.6.4 Mechanical Seal

One cartridge mechanical seal is fitted. Single, tandem or double seals are available, and liquid barrier is standard. Gas barrier seals may be also available. Unusually, the seals are proprietary to the pump vendor.

Single / tandem seals are reliant on flush liquid derived from the pump. This is a weak spot on many vertical pump designs, as the seal, being at a high point, tends to trap air / gas. One known high speed design uses a pressurised flush which avoids this problem. The issue does not apply to double seals.

For details of Mechanical Seals and related hazards see **Sections 5.3.3** & **5.3.4**.

4.12.6.5 Gearbox and Bearings

The pump shaft is supported by radial bearings inside the gearbox. These bearings thus receive a good supply of high quality oil that is well protected from product contamination.

The gearbox is of aluminium construction which is thus relatively weak and easily damaged. As the gears and bearings share the same oil, gear damage will soon result in bearing damage. It is necessary to take great care to keep the internals of the gearbox clean, and to inspect for any damage to bearing housings, debris / blockage in drillings.

There are 2 gearsets, with ratios defined by the required pump speed. The input shaft (driven by the motor) is co-axial with the pump shaft, for convenient assembly. As the gear meshes and pump seal alignment are all fixed by the gear casing geometry, any distortion or damage to bearing locations should require matched replacement parts. Repair e.g. by sleeving and re-machining, is a poor option.

There is an internal oil pump, shaft driven. The lubricant is Automatic Transmission Fluid, not standard mineral oil. It is highly coloured, making oil leaks very obvious. The oil level should be checked on a routine basis.

For details of Bearings and related hazards see **Section 5.9**.

4.12.6.6 Support Systems

Baseplate

Vertical pumps have a simple mounting pad, as this is just to carry the pump weight. Pipe weights / stresses should be carried by pipe supports such that pipe loads do not affect pump alignment. Hence pumps can be included in a module with no special provision. The pump is not designed to act as a pipe anchor.

Horizontal design high speed pumps are available, and these do require a stiff baseplate as the drive motor is mounted on the baseplate, and not flange mounted to the gearbox.

Lubrication System

Bearing and gear lubrication is integral to the gearbox. No external connection is involved, other than water cooling for larger models.

Seal Support System

Liquid support system is traditionally a pressure pot with thermosyphon cooling, containing a compatible clean fluid (e.g. light hydrocarbon oil).

Pump Recycle System

See **Section 4.6.6.6** for generic information & **Section 4.12.3.3** for information specific to high speed pumps.

4.12.6.7 Control & Management Systems

See **Section 4.6.6.7** for generic information.

Additionally, since the head generated by high speed pumps is very high, they are very sensitive to speed fluctuations, particularly if feeding into a shared manifold or other common user system. The control of the driver, if variable speed, should be designed for tight speed control / slow ramping.

Similarly bringing pumps on and off line requires care & appropriate use of the recycle, to avoid pressure surges.

4.12.7 INTEGRATION ASPECTS

4.12.7.1 Process Duties

High speed pumps have a rather narrow acceptable flow range compared with other pump types.

4.12.7.2 Mechanical Integrity of Pump

When the Back Pull Out unit is removed, the impeller is exposed and will be damaged if the unit is laid down carelessly.

4.12.7.3 Coupling Alignment

The coupling alignment is dictated by build quality & spigots on housing sections. If misalignment is suspected, frequency analysis on vibration signal from motor NDE should reveal any problems. It may be possible to fit clock gauges once the coupling has been removed. If satisfactory alignment cannot be achieved by careful re-building, cleaning up burrs, etc., then the unit will have to be factory rebuilt.

4.12.7.4 Condition Monitoring

Oil temperature, pressure and condition, seal support system pressures, are the most valuable parameters to monitor. General vibration readings are of little value as the high gear noise swamps other effects.

4.12.7.5 Protective Systems

See **Section 4.6.7.5** for generic information.

Additionally there should be an oil pressure trip, and seal support system fault trips.

SECTION 4.13

PUMP – RECIPROCATING PLUNGER TYPE

CONTENTS

This report section covers a Reciprocating Plunger Pump on additive handling. It also covers plunger operated Diaphragm Pumps. To avoid unnecessary duplication, generic remarks in **Section 4.6** will not be repeated, but are referenced.

Target duty for plunger pumps is the injection of liquid additives into the process.

This section does not cover simple air operated double diaphragm pumps as they do not have a pressure multiplying capability, and are not in general suitable for continuous service.

4.13.1 INTRODUCTION

- ***Reciprocating plunger pumps are used to handle very small flows at a range of pressures.***
- ***The key requirement is an accurate metering capability.***
- ***If the additive is not suitable for handling directly in the plunger mechanism, plunger operated diaphragm pumps are used.***

Reciprocating plunger pumps are selected for low flow duties that require accurate metering. The pump comprises a reciprocating plunger, mechanically driven, operating in a cylinder fitted with suction and delivery valves. If the additive is not suitable for contact with the plunger mechanism, a flexible diaphragm is used to isolate the plunger from the fluid. The plunger then operates in hydraulic oil.

Onshore, pumps are built with an electric motor drive via a gearbox and crankshaft. Offshore, to avoid the use of electric motors in hazardous areas, the pumps are often built with an integral air operated piston drive.

4.13.2 BACKGROUND & HISTORY

- ***Reciprocating pumps have been used for many years in the process and water industries.***
- ***Original designs used a simple packed plunger to pump chemicals e.g. into batch reaction vessels***
- ***As concern grew about hazardous materials, and to improve pump life, various diaphragm or tube pumping designs have been produced.***
- ***Improvements in design and materials have increased the MTBF.***

Early chemical plants typically worked by processing chemicals in batch reactors. Once under pressure, any additional reagents had to be pumped in. Reciprocating pumps were developed to work against the moderate pressures required. The pumps typically had a motor, gearbox, crankshaft and plunger. The plunger fitted into a cylinder, and used soft packing, as in early centrifugal pumps. Some leakage was accepted. Suction and delivery valves were fitted into the cylinder head.

As pressures increased, better materials and manufacturing techniques were developed. To provide a variable metering capability, various proprietary mechanisms were developed to vary the stroke length to control the flow rate. Variable speed was also used.

For materials that were difficult to handle, designs were developed which used a flexible diaphragm to pump the fluid, avoiding contact with sliding parts and avoiding leakage. The diaphragm was operated mechanically or hydraulically.

For offshore and other hazardous area use, air operated pumps were developed.

4.13.3 HAZARD ASSESSMENT

- ***The hazards posed plunger pumps relate primarily to the additive fluid, which is often toxic, corrosive, flammable.***
- ***The pumps often work at high pressure but flowrates are too small to sustain a significant liquid jet.***
- ***See Section 2.5 for general hazards of additive handling, and process consequences of mis-handling.***

4.13.3.1 Process Substance Containment Hazards

See **Section 2.5.1.3.4** for information on additive storage and handling.
See **Section 2.5.1.5** for information on general and consequential hazards from additives.

There should be no fluid hazard from the pump in normal service. Plunger pumps may weep slightly at the packing, there should be a drip tray or similar to deal with this. A failed pipe connection could give a spray but the flow will be very small, so will not pose a risk of physical injury from the jet.

The greatest risk is of chemical injury from the fluid itself, particularly to eyes, face, hands. There should be a system in place to control access to pumps handling hazardous additives, transparent shields may be fitted around the pump, and appropriate PPE specified. It is vital that up to date chemical safety data sheets are available for each additive currently in use, and that these are converted into useful instructions for the operators.

4.13.3.2 Equipment Hazards

See **Section 4.6.3.2** for generic information about pumps.

There should be no mechanical hazard from the pump in operation. Putting fingers into ports might risk injury. Chemical reaction between wrongly mixed additives, chemical decomposition, or violent chemical attack of wholly unsuitable materials, could generate sufficient pressure to rupture the pump. There will then be a local mechanical hazard, but the main hazard will be release of, probably boiling, additive.

4.13.3.3 Operational / Consequential Hazards

See **Section 2.5.1.5** for general information on Operational Hazards from mis-applying additives.

4.13.3.4 Maintenance / Access Hazards

See **Section 4.6.3.4** for generic information.

In most cases, the pump must be flushed out with a non-hazardous material. Ideally, a non-toxic, process-compatible fluid is pumped through the system for sufficient time to remove all traces of the additive. This fluid can then be drained off as part of the pump disconnection process.

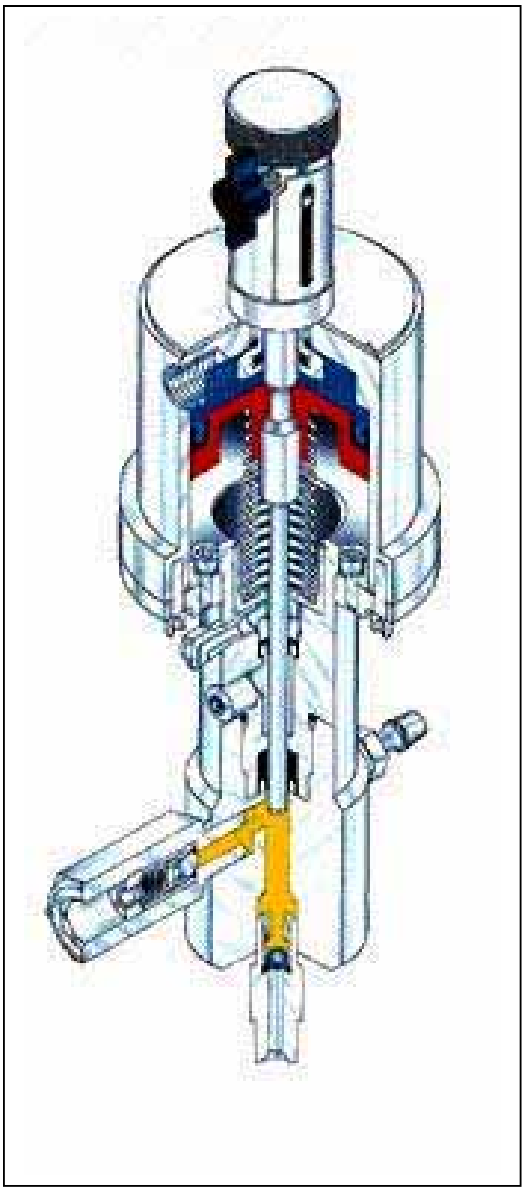


Figure 4,13 – 1

Cut-away Air Operated Plunger Pump

The most important issues are physical disconnection of the pump from additive liquid connections, and from the supply air connection.

It must be recognised that additive may be trapped inside the pump, particularly if the pump has failed in service and has not been properly flushed. Even after flushing, liquid can be trapped under gaskets and in valves. Diaphragm failure can result in contamination of mechanical and hydraulic systems.

The pump maintenance instructions must state clearly if there is any stored energy in the form of gas or spring pressure, which must be released under control.

Note that if a pulsation damper is fitted, this can pressurise the relevant pipework with liquid even after disconnection of the air supply. An additional release of gas (normally nitrogen) under pressure is possible if the pulsation damper flexible membrane fails. If the membrane has failed in service (usually the case), a quantity of liquid will be trapped behind the membrane and may be released if the pressurisation valve is opened.

Any heat applied to pump or pulsation damper may cause release of chemicals as liquid or vapour. Heat above about 100 C may permanently damage plastic or elastomers, heating above about 250 C will degrade elastomers and in particular PTFE, releasing highly toxic and corrosive gases (HF, HCl).

4.13.4 OPERATING REQUIREMENTS

Plunger pumps are self-priming (given a clean fluid and undamaged valves) but require a low back pressure on the delivery side until fully primed. A vent valve with sight glass, piped to an appropriate drain or, in extreme cases, container, is appropriate. Pumps may contain a vent nipple, identical to an automotive brake bleed nipple, suitable to fit a clear polyethylene pipe.

Pumps normally run continuously but may be operated by timers. Some form of operator information (typically pulse counter or pulse rate, delivery pressure gauge) is required.

Some system should be in place to alert the operator prior to the IBC or storage running empty. Operating instructions should make clear whether the pump is to be run until the container is empty (which will probably air-lock the pump), or changed over leaving a heel of material in the IBC.

4.13.5 MAINTENANCE REQUIREMENTS

- ***Plunger pumps are designed to be overhauled in workshop conditions, although it is possible to service the valves in situ.***

It is assumed that the complete pump will be removed to workshop conditions for any maintenance. The only site work thus required is lubrication, connection and disconnection of pipework, & operational checks. Usually, it is possible to service the valves in situ.

Pumps must be clearly identified, as the internal process contact materials, and the pump capacity, cannot be determined visually. Pumps should be marked as to what additive was being handled, and what level of decontamination has been achieved, prior to removal from the module.

Typical wear parts are the plunger, packing, diaphragm (if fitted) and valves. Gaskets and O rings should be changed as a matter of course. Correct materials must be used, particularly for elastomers. The packing system may have to be adjusted on site once the pump is back in

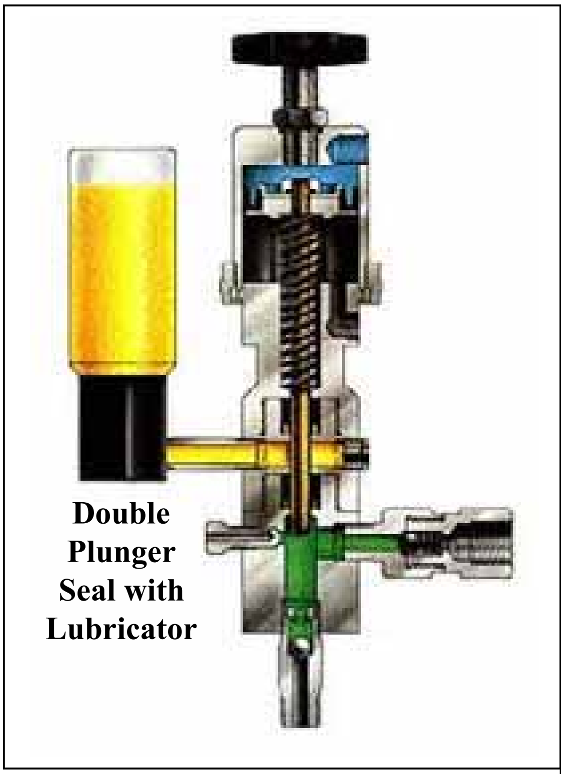
service. Hydraulically operated diaphragm pumps contain hydraulic oil, which must be drained off. This should be non-hazardous unless the diaphragm has failed.

4.13.5.1 Internal Corrosion

See **Section 4.6.5.1** for generic information.

Contact parts should be in corrosion resistant material. Incorrect matching of parts with fluids (e.g. due to swapping of “similar” pumps) can result in very rapid corrosion. Damage to diaphragm or plastic linings can result in corrosion of the underlying material. Since the pump should be installed over a bund or containment, and the quantities handled are small, the consequent release should be small.

4.13.6 PLUNGER OR DIAPHRAGM PUMP MAIN COMPONENTS



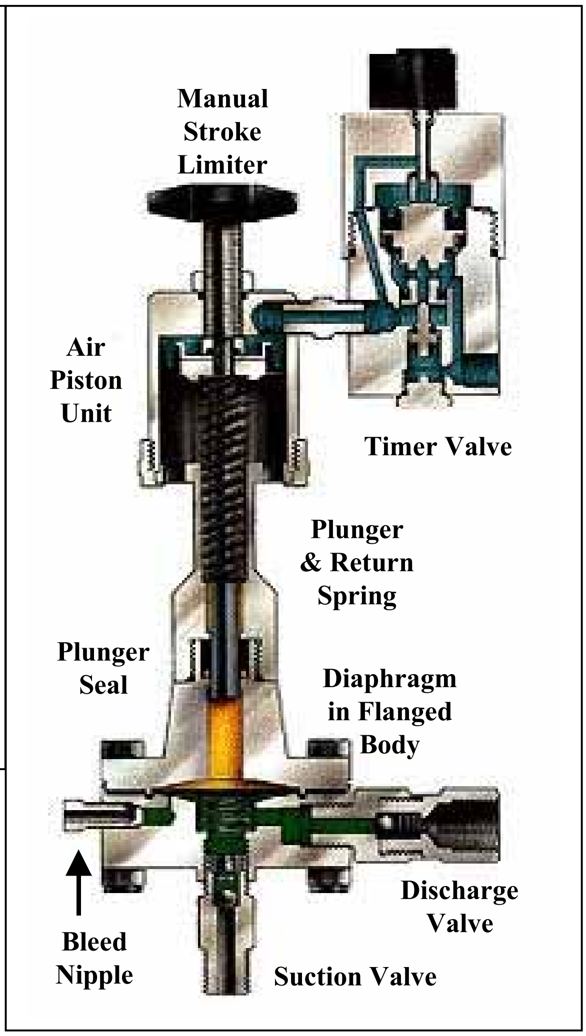


Figure 4,13 – 2 Cross-sections of Air Operated Plunger Pump (above) and Diaphragm Pump (right) with timer valve.

4.13.6.1 Pump Body

This is a cast or machined housing, drilled to take plunger, seals and valve fittings. It has mounting feet or a bracket. The air piston unit is screwed onto one end.

4.13.6.2 Air Piston Unit.

This is mounted on the housing and linked to, or integral with, the plunger. Leakage from the plunger must not enter the air piston. The unit will be fitted with a timer valve; this provides a pulse to stroke the pump plunger, then permits the plunger to return to start. Return motion is by a return spring fitted under the piston, or by a double acting piston. An upstream air filter is required to protect the valve from dirt, which could cause it to jam. The nominal pump discharge pressure is given by taking the supply air pressure, and multiplying by the ratio of air piston area to plunger area. Stroke length may be controlled by a mechanical limiter mounted on top of the air piston unit.

4.13.6.3 Cylinder

The cylinder bore is drilled into the pump body. It carries the valves, or the diaphragm, at its outer end. The inner end is fitted with a sophisticated packed gland system, the packings are pre-shaped and pressure actuated. Double packing may be used, with the inter-space lubricated and vented to a safe place.

4.13.6.4 Plunger

This is a machined rod, running in the cylinder and acting as a piston. To minimise wear from the packings, plungers are often hard coated, for example with Chrome Oxide. The plunger is linked to, or part of, the air piston. The plunger travel must be limited, to prevent impact with the cylinder end, or pulling out of the packing. Since the plunger is single acting, it only pumps on the forward stroke, this inevitably causes pulsations in the upstream and downstream pipework.

Control of pump capacity can be made by adjusting the frequency of operation, or stroke length, of the plunger. Note that plunger operation does not guarantee pumping.

4.13.6.5 Diaphragm and Hydraulic System

Simple plunger pumps allow contact between the additive fluid and the plunger. Where this would damage the plunger or packing, or if any leakage in service is unacceptable, a diaphragm pump design is used.

The hydraulically actuated diaphragm design mounts a flanged body between the plunger and the valve end of the cylinder. A flexible diaphragm, typically made of Viton (elastomer) with a bonded PTFE facing, is trapped in the flange. The plunger may be fitted with a hydraulic reservoir and filling valve, very similar to an automotive brake master cylinder. The space above the plunger is completely filled with oil; thus as the plunger moves, it displaces the diaphragm. As the plunger draws back, it creates a partial vacuum, drawing back the diaphragm. The filling valve acts to keep the interspace full of the correct amount of oil, and vents any air. The diaphragm, moving up and down through a small displacement, acts as the pump.

The diaphragm normally operates between two concave discs, which act as travel limiters. Otherwise the diaphragm could be over-stretched and tear. It is quite common for the diaphragm to be made of “sandwich” construction, with a vacuum pulled inside. Delamination of the diaphragm, as a prelude to failure, breaks the vacuum and triggers an alarm. The vacuum switch could be contaminated and should be changed, but the rest of the pump should be clean.

Mechanically actuated diaphragm pumps replace the hydraulic plunger system with a mechanical link direct to the diaphragm. This is much simpler but normally requires a stronger metal diaphragm. This diaphragm tends to suffer from fatigue cracking and has a shorter life

than the hydraulically actuated unit. Mechanical diaphragm pumps also tend to be less accurate in their metering, this is unimportant if the metering rate is on some form of feedback control.

4.13.6.6 Valves

Apparently simple, gravity or spring assisted valves are used to ensure forward flow. Thus the bottom valve is the suction, the top or side one is the delivery. Proprietary single or double valves, ball, cone or flap types, in various materials, are selected by the pump vendor to suit the stated fluid properties, based on previous experience. The valves and their mountings are quite fragile and are easily damaged by over-tightening.

4.13.6.7 Pulsation Dampers

Although not part of the pump, and often supplied by a different vendor, pulsation dampers can be the key to a working system. They are a pipe fitting consisting of a pressure container fitted with a gas filled bladder. With the correct pre-charge pressure, a pressure pulse is substantially absorbed in the damper, rather than passing down the pipework. Particularly in suction systems, it is the negative pressure wave that causes the problems, dissolved gas is drawn out of the fluid and gas locks the pump. Downstream problems can include shaking and damaged pipework and instruments, and leaking fittings. Failed pulsation dampers can significantly <u>increase</u> the dosing rate of a system.

Pulsation dampers can only be properly checked by measuring the gas charge pressure with the pipework de-pressurised, although excessive pulsation indicates problems. Pressure gauges whose pointers have fallen off are a sign of pulsation.

4.13.6.8 Control & Management Systems

See **Section 4.6.6.7** for generic information.

The pump will normally be controlled to achieve a desired injection rate, determined by design, periodic laboratory testing of samples, or on-line process measurement. It is difficult to measure small injection flows, particularly with pulsations, thus pump stroke counting and IBC's on load cells are legitimate methods. Note that a pump with faulty valves might pump faithfully and deliver nothing. Reverse flow has been known, where the additive stock tank level rose in service. The problem was identified by an alert stores operative, routine purchases of the additive had stopped for some weeks.

4.13.7 INTEGRATION ASPECTS

4.13.7.1 Process Duties

The pump must be matched to the duty. Too small a pump will run too quickly and wear out, too large a pump is simply expensive. The discharge pressure (determined by the air piston and pump plunger sizes) must be in the right range. Process contact materials must be correct.

4.13.7.2 Alignment & Adjustment

The piston and plunger should be inspected during maintenance for wear or damage. The mechanism should move freely by hand, through its full travel, without binding. The air piston should reach its travel stop before the plunger reaches the end of the cylinder.

4.13.7.3 Mechanical Integrity of Pump

Metering pumps are strongly bolted together, but the pipework connections and valve fittings are often in plastic to withstand aggressive chemicals. These connections are easily damaged. Hence the preference to mount the pump a little higher than the source liquid level, and to fit a non-return valve in the fixed discharge piping.

If the mechanism incorrectly adjusted, or the supply air pressure is too high, the mechanism will be subject to excessive accelerations or pressure forces, and can be damaged. Particularly with diaphragm pumps, this should not lead to a loss of containment, but note comments on the fragility of small bore connections.

4.13.7.4 Condition Monitoring

Smooth operation can be heard / felt as the pump operates. A check of the stroke rate vs. the actual pumping rate will indicate pumping efficiency. Visible leakage will indicate weeping connections or seals.

4.13.7.5 Protective Systems

See **Section 4.6.7.5** for generic information.

Unless the mechanical loads are limited by the air piston system and air supply, a pressure relief device is required on either the hydraulic system (which is clean) or the discharge pipework. If it is determined that their is a hazard from either under or over-supply of additive, a combination of stroke counter and load cell measurement should be used to raise an alarm if outside reasonable limits on flow (rate of change of storage weight) or storage level.

SECTION 4.14

POWER GENERATING SET (ALTERNATOR)

CONTENTS

This section covers Industrial Alternators (A.C. Generators). Typical sizes are from 250 kW to about 50 MW. Above this size alternators are designed for Onshore Utility operation. Alternators will operate at either 50 Hz or 60 Hz, depending on location. Onshore, alternators may be linked into local or national grid systems.

See **Section 3.3 Appendix 1** for Electrical Terminology.

- ***Alternators are available from a few watts to > 600 MW.***
- ***Industrial Alternators typically cover 250 kW to 50 MW rating.***
- ***Industrial Alternators generate power at a specific supply frequency, this is 50 Hz for European sites, and 60 Hz for North America and many offshore installations.***
- ***Alternators may operate alone or linked to grids.***

4.14.1 INTRODUCTION

- ***Alternators convert mechanical energy from the prime mover to A.C. electrical current.***

- ***For offshore installations the choice of driver will be between Gas Turbine and Diesel Engine.***

- ***The A.C. frequency is determined by the shaft speed, and is normally 50 Hz or 60 Hz.***

Alternators convert mechanical energy to electrical energy by rotating a powerful magnetic field inside a set of electrical coils. Although the units vary from a few watts to in excess of 600 MW capacity, the basic concept and construction remains very much the same. For technical reasons, standard alternators produce 3-phase current, although single-phase and multi-phase units are possible. Industrial units are typically in the range 250 kW to 50 MW, to suit the available drivers. Offshore, the choice lies between gas turbine and diesel engine, while onshore steam turbine drive (as part of a plant utilities or process steam system) is common. The generating voltage is to suit the local distribution rating, thus typically 415 V for small sets through 10 kV for very large ones. Transformers are used for voltage matching and linking to any bus system. Mechanically, industrial alternators are very similar to synchronous electric motors, and many of them can also be used as motors when required.

4.14.2 BACKGROUND & HISTORY

- ***Early generators were D.C., but alternators became preferred as larger sizes and higher efficiencies were exploited.***

- ***The fundamental construction of alternators has not changed, but reliability has steadily improved.***

The earliest generators produced D.C., but practical D.C. generation is limited to about 500 kW by the brushgear. As the demand for electricity grew, larger and more efficient alternators were developed, outstripping D.C. capability. As transformers and improved rectifiers were developed, even D.C. loads were supplied by A.C. generation. As modern switchgear, semiconductors and control systems have developed, reliability has steadily improved, as has the capability for fully automatic operation.

Alternators are particularly suitable for interconnection via grid systems, loads are shared and individual machines switched in and out of circuit to meet changing demand.

Figure 4,14 – 1 Commercial Emergency Generator Unit (Alternator at R.H. End)

4.14.3 HAZARD ASSESSMENT

- ***Alternators are generally Low Hazard items as they do not contain Flammable Materials, also live and moving parts are well guarded.***
- ***Alternators are known for internal spark generation, particularly under fault or starting conditions.***
- ***External surfaces should not be capable of becoming hot enough to ignite flammable materials.***
- ***Mechanical damage or poor maintenance can result in mechanical rubs, exposed live or moving parts.***
- ***Traditionally, alternators had a simple form of brushgear to transfer power to the rotor. Modern "brushless" machines have removed that problem.***
- ***If an alternator is abruptly disconnected from its load, the driving machine may overspeed if the control system does not react properly.***

4.14.3.1 Ignition / Explosion Hazards

Alternators should have no exposed electrical conductors and there should be no spark generation by the main stator and rotor windings in normal operation. Contact with High Voltage conductors is likely to be fatal.

Alternators may have brush gear and slip rings to power the rotor coils. This gear will have bare conductors and may generate sparks in service, particularly if the interior of the unit is dirty. The conductors should be fully shielded in service. Many modern alternators are "brushless", transferring power to the rotor via induction coils.

High Voltage alternators can generate internal "brush discharges" from the rotor under some circumstances. In addition, damaged or incorrectly built rotors can spark in normal service as internal currents jump across damaged insulation.

For water cooled alternators, this is not normally a problem because the air space inside the alternator is quite well sealed from the environment, and inaccessible to people. In the event of a flammable atmosphere being present external to the unit, flammable gas will diffuse through the shaft seals into the alternator core, creating a flammable mixture inside. An internal spark could then ignite the gas.

For smaller units, direct air cooling may be used. This is much simpler and cheaper, but leads to dust, moisture and salts being drawn into the core of the unit. Should a flammable atmosphere be present externally, it will be drawn into the machine, and ignited by a spark or hot surface.

Various philosophies are adopted to prevent the potential major explosion which might result, these are codified in the same way as for electric motors, using "Ex" motor codings. See **Section 3.4.3.1**

Most industrial alternators are not designed to cope with flammable gases and can be installed in "safe" areas only. For offshore applications, this would require the unit to be installed inside an acoustic enclosure with an atmosphere managed and monitored to prevent the ingress of significant quantities of flammable gas. It is possible to obtain alternators suitable for zoned areas, but it is difficult to see how the associated driver is to function safely.

4.14.3.2 Equipment Hazards

Under normal operation, an alternator can be treated in exactly the same way as a high voltage motor.

The special case is overspeed. Normally, the shaft power fed into the alternator is matched by the electrical load. Under certain fault conditions, for example a switchgear failure, the complete electrical load is disconnected instantly. The engine governor must be able to cope with an instant change from full load to no load. This process is referred to as "Full Load Rejection". In practice, the alternator rotor has quite high inertia, and engine fuel systems react very quickly, so there is no good reason why the system will not work. It is still necessary to carry out periodic trip testing, with a simulated full load trip after any relevant maintenance work. Actual full load trip testing carries a risk of an actual overspeed event, and should only be done when the risk is justified, perhaps once after commissioning. Thereafter, a log should be kept of all load rejection events, with a record of the maximum speed reached if available.

There is a known risk of load rejection during "synchronisation" to a grid or distribution system. Appropriate operating procedures are required and should be followed.

4.14.3.3 Operational / Consequential Hazards

In normal operation an alternator should pose little threat to the safe operation of the installation.

Industrial alternators lose around 5 – 10 % of their rating as heat. They have an internal air cooling circuit, the hot air is then exhausted to atmosphere, or cooled against cooling water. As 5 % of even a 2 MW rating is 100 kW, air cooling is only used for smaller, typically emergency or standby, sets. If ventilation is lost, the area will overheat very rapidly and the alternator must be shut down. Air cooled units also get dirty inside, despite air filters.

Failure of the alternator or its switchgear will remove power from the driven equipment, which may have an impact on the process. Particularly during major load changes, electrical spikes can be generated which can damage electronic and computer equipment. Such equipment should be fitted with electrical protection filters and/ or screening.

Under some engine governor fault conditions, the supply frequency and voltage may exceed normal bounds. The electrical switchgear protection system should be set to trip the supply before, for example, motors overheat (low frequency or voltage) or compressors overspeed (high frequency).

4.14.3.4 Maintenance / Access Hazards

High Voltage alternators can be physically quite large, normally in the form of a rectangular box. Access is by bolted panels and terminal box covers.

Alternators are usually located inside acoustic enclosures, these may be shared with the drive turbine or engine. It may be very noisy or hot, particularly if two units share an enclosure. Alternators are very heavy (see Nameplate for weight). Rigging points will be provided. The maker's instructions should be checked for arrangements to release drive couplings and power cables.

If the entire package has not been shut down, adjacent equipment may not have been isolated or may even be running.

4.14.4 OPERATING REQUIREMENTS

- ***Alternators are very tolerant of variable operating loads, but the drive engine's governor may not be so tolerant.***
- ***Operating on zero or very low load may tax the driver governor and result in poor speed and thus frequency control.***
- ***If excessive load is applied, the control system may be able to "shed" part of the load, otherwise the whole load will be rejected.***
- ***If an alternator is to be linked to a grid ("synchronised"), this significantly alters the way in which it is operated and controlled.***

The most benign operating pattern is continuous operation, alternators are very tolerant of load changes, within the design range. Since the load change impacts on the driving engine's governor, abrupt load changes or operation on very low load may lead to poor speed control and thus poor frequency control. Alternators linked to a grid system (as is typical onshore) are much less sensitive to load changes. Brushless alternators can operate for 3 years and more without maintenance, subject to routine lubrication, cleaning, condition monitoring as required.

Alternators have no real restrictions on starts, stops and speed changes, the limit is with the driving engine and constraints like fuel system purge times.

If the applied load exceeds the limits of the alternator or the driving engine (which will have been matched), then either the supply voltage or the supply frequency (drive shaft speed) will drop. If this drop exceeds safe limits, then load must be reduced immediately or the drive will trip. Some control systems are designed to "shed" or disconnect excessive loads, on a priority basis. Such systems are notoriously difficult to set up and monitor, frequent spurious trips might be one good indicator of problems in this area.

A single alternator feeding one or more loads is very simple to start up and operate. This arrangement typically applies to an emergency generator, where it is assumed that there will be a complete power failure, which can be sensed by voltage loss relays. The alternator is permanently connected to the drive engine, which is started normally. Once the system is up to normal speed and has settled down, the speed and load controls are put into automatic mode and the alternator connected to the supply circuitry. Some load will be switched on automatically, e.g. lighting, and other loads will be switched on in turn. The additional load on each occasion causes the alternator and engine to slow down until the governor feeds more fuel and brings the unit back up to speed. Reduction in load has the opposite effect, with the governor reducing the fuel supply as required.

Multiple alternators linked together, whether on a single installation or a national grid, operate differently. Here the load is continuously supported by a number of alternators, ideally working close to, but not at, full load. If there is additional demand, or a running unit is to be switched off for some reason, an additional alternator must be connected. In this case the drive is run up to speed as before, but now the supply circuitry is already live. The control system will very gently adjust the speed of the drive, and even the shaft position (described in effect as the "phase" of the generated voltage), until there is an exact match. Only then is the switchgear closed and the alternator starts producing electricity. This process is described as "synchronising" and is now normally automatic. Historically, synchronising was manual and could cause spectacular switchgear damage if the alternator was put on line out of synchronism.

Once an alternator has been synchronised it is locked into the common frequency, the control system has the much easier job of monitoring the electrical load allocated to the particular machine, and providing the correct amount of fuel.

Alternators can tolerate long periods out of service (e.g. on stand-by), provided they are kept warm, dry and in particular protected from high-frequency vibration. This vibration can cause bearing damage ("brinelling"). Electric heaters are fitted to prevent internal condensation. Emergency or standby units should be test run regularly, more for the benefit of the driver than the alternator.

Alternators work in fixed berths and have operating limits on tilt and acceleration. These limits will be defined by the manufacturer.

4.14.5 MAINTENANCE REQUIREMENTS

- ***Apart from brushgear (where fitted), alternatorss require very little maintenance. Specialists must be employed for major work.***

The only routine maintenance is cleaning, inspection and lubrication. Other work should be carried out in workshop conditions. Smaller units can be lifted complete but for larger units it is more practical to remove components.

Bearings, fans and heat exchangers may be serviced or repaired in situ. The rotor must be removed to a specialist repairer for any work, the removal process is very tricky as the rotor is "threaded" through the stator with very narrow clearances. Minor electrical repairs to the stator can be done in situ, otherwise the stator must be removed. Major work can take many weeks.

Most designs will have oil lubricated bearings, typically roller bearing cartridges with an oil feed from the driven equipment oil console. Smaller units may be grease lubricated.

As the outgoing connections must match the supply system phase order, careful checks are required if any wiring has been disturbed. Incorrect wiring or testing can result in huge fault currents, sufficient to start fires or burn out major components.

Maintenance records must be updated after any overhaul work.

4.14.6 ALTERNATOR – MAIN COMPONENTS

- ***The rotor is driven by the drive shaft from the diesel engine or gas turbine.***
- ***The rotor carries coils, which are energised to create powerful magnetic fields.***
- ***The stator carries electrical windings, which generate power.***
- ***An "exciter" on the end of the rotor, feeds power to the rotor coils.***
- ***Rolling element or white metal bearings are fitted.***
- ***Cooling air is moved by internal fans.***

The construction of an industrial alternator is almost identical to a high voltage synchronous motor.

4.14.6.1 Frame

The frame is normally of fabricated carbon steel, typically a box section chassis supporting the stator and bearings, with a lighter sheet steel box forming the air circuit and supporting terminal boxes, heat exchanger. Bolted panels give access to the interior.

4.14.6.2 Stator

The stator has the mechanical purpose of supporting the windings, and is mounted on the frame. It consists of a pack of thin metal laminations made of a special steel alloy called "soft iron". Insulated copper wires or bars are wound into shaped coils and bonded into slots in the laminations. The coils are connected to the main terminal box, forming the electrical generating circuit of the motor. The cables from the terminal box connect to the supply switchgear.

Most of the heat generated in the stator is removed by cooling air passing through slots & circulated by fans on the rotor.

Terminal boxes are typically of sheet steel and provide sufficient space to gland off and terminate supply power and signal cables.

4.14.6.3 Rotor

The rotor consists of a carbon steel shaft running in two bearings, fitted with a set of insulated copper coils fitted through "soft iron" laminations. The Drive End of the rotor extends beyond the Drive End bearing, and is shaped and keyed to carry a coupling. The Non-Drive End of the rotor carries the Exciter. The exciter component on the rotor receives power from its static component, and feeds wires which run through inside the NDE bearing to power the rotor coils.

This power may be transferred by a rotating slip ring system, or by the newer “brushless” induction system. Slip rings look similar to D.C. motor brush gear, but are not subject to the same wear and unreliability issues. The “brushless” system looks like a very short, large diameter electric motor fitted to end of the main rotor, in effect it is a rotating transformer.

4.14.6.4 Exciter

The exciter is an electrical device which takes a small amount of power from that generated by the alternator, and feeds it back into the rotor to power the magnetic fields which generate the power. The exciter comprises a control element, a rectifier element and a pair of elements to transfer the power to the rotor.

The control element receives control signals from the alternator control cabinet and determines how much power to feed into the rotor coils. In modern systems this unit will be electronic.

The rectifier element, again solid state, produces the D.C. power required for the rotor coils.

The power transfer is achieved by brush gear or coils, as described in **Section 4.14.6.3** above.

4.14.6.5 Bearings & Lubrication

The shaft bearings are typically in cartridge format, supported by the end cross-members of the frame. Simple labyrinth seals exclude dirt and water. Normally the NDE bearing is axially located, the DE bearing has some axial float.

Smaller units have rolling element bearings, larger units typically have plain white metal bearings.

The avoid stray electrical currents, it is normal for the bearing to be insulated from the frame. One bearing only is then earthed via a link.

Where oil lubrication is used, the bearings may be self-contained or be oil fed. Even oil fed bearings often have a small oil reservoir to cover run-down in the event of oil supply failure.

For further information on Ancillaries, see **Section 5.2 for Lubrication Oil Systems**, and **Section 5.9 for Bearings.**

4.14.6.6 Cooling System

In open air cooled alternators, fans are fitted to the ends of the rotor. These draws air in through a perforated grille, and perhaps a filter, and blow it through the cooling slots in the rotor and stator. Exhaust air returns to atmosphere. Even with a filter, the interior tends to become dirty. Flammable or corrosive gases may be drawn in.

On water cooled alternators, the internal fans circulate air against water cooled coils, mounted either internally or on top of the frame. Cooling water is supplied by the main plant system. There should be a system to collect and detect any condensation or leakage from the cooling water coils.

4.14.6.7 Control Systems

All alternators require switchgear to link them to their loads. Smaller machines will have a mechanically operated switch (the "isolator"), an electrically operated switch (the "contactor"), a set of fuses and an overload trip device.

Larger machines will have fault detection devices e.g. thermistors, phase fault relays, these are linked to a trip relay which will trip the drive, reject the load and de-energise the rotor coils.

The control equipment is generally located in a separate cabinet or cabinets. One part of the system monitors the load being taken and checks for faults in the power circuits. If the alternator is operated in synchronised mode, this system will control the load via the drive engine control system. The system controls the exciter to generate the appropriate voltage and current to meet the demand.

Another part of the system monitors the frequency and phase of the generated current. When the alternator is operating alone, this system serves only to raise alarm or trip signals if values go outside the acceptable range. When the alternator is to be synchronised with an existing supply, the control system signals the engine control until there is a match, when the main contactor is closed.

Note that speed control, when required, is done by the engine / driver control system, which is responsible for overspeed control and trip actions.

High voltage electrical conductors are potentially fatal, so access to high voltage equipment is normally restricted to specially trained personnel.

4.14.7 INTEGRATION ASPECTS

Industrial alternators are built to order. Generally the supplier will select the appropriate unit for the duty, but it is much better if the client or contractor's rotating equipment and electrical engineers are consulted. Hazardous area requirements are fundamental, as these safety features cannot be added afterwards.

The range of loads to be fed must be considered, particularly for a unit which will operate in “stand-alone” mode. For example, reciprocating compressors can have a rapidly fluctuating torque characteristic that may cause problems with other machines on the same power net. The electrical characteristics of the loads may require additional electrical components to prevent excessive “reactive” currents, which waste energy.

The design of the power network is a skill in its own right, particularly if large drives must be started, or if parts of the system are to be dropped or “shed” in emergency.

Inverter drives can produce harmonic signals that can impact on control systems or damage electrical equipment. The larger the drive, the bigger the potential problem. Use of high voltage inverter drives requires the active input of a competent electrical engineer.

Specialist contractors who apply considerable experience of previous installations generally design emergency generator packages. The designs must be tested against the needs of the client, but the design philosophy differs from normal process plant design.

4.14.7.1 Cleanliness

Water cooled alternators are insensitive to dirt, unless it actually gets into the bearings or inside the casing. Internal cleanliness is important, otherwise dirt will foul heat exchanger surfaces. Oil contamination inside the machine poses a fire risk.

Air cooled units are sensitive to dirt in the surroundings, particularly if in an open ventilated enclosure and with no air inlet filters.

4.14.7.2 Mechanical Integrity

Alternator rotors turn at relatively low speeds and are contained within massive housings. Ejection of parts is very unlikely. Alternators are heavy and require a rigid mounting structure, poor mounting can distort the frame, causing vibration and potential damage.

4.14.7.3 Condition Monitoring

Vibration monitoring, in particular by trending, can identify a range of machine problems. For details of Condition Monitoring Systems and related hazards see **Section 5.12.**

Modern alternator control systems have a number of integral monitoring functions for protection purposes, but do not usually record and trend. Specialist electrical test equipment can be connected to alternators, and can be used to detect a range of electrical and mechanical problems. A high level of interpretative skill is required. Routine use of this equipment cannot usually be justified, unless several alternators are installed, or equipment is shared with other installations. Symptoms like electrical faults, overheating or strange noises will prompt further study.

4.14.7.4 Protective Systems

As well as the protective functions already described in the alternator control systems, normally there will be temperature sensing devices in the bearings, coils and internal cooling air circuit. These may display locally or in the control room, or simply operate protective devices. It is normal to have pre-alarm and trip on each temperature.

It is important that the protective systems are integrated with those in the driver and ancillaries.

4.14.7.5 Bearings

Where the bearings are oil fed, the oil supply may be derived from the driver, or from a small dedicated oil console. Diesel engines in particular suffer from fuel and carbon contamination of lubricating oil, which is best confined to the engine itself. The driver must be interlocked to the supply oil pressure, and tripped if the pressure falls.

4.14.7.6 Sealing

Alternators have simple labyrinth shaft seals on the air circuit, they should be reasonably dust tight and hose proof (IP55) but are not gas tight. It is good practice to set up terminal boxes and cable glanding to avoid water ingress down the cable. Terminal boxes are not isolated from the internal air space.

After maintenance, the dust and water tightness will be lost if the panel seals are damaged or ill-fitting.

4.14.8 CONTROL

- ***The alternator control must be integrated with the driver control system.***

The alternator control must be integrated with the control of the driving machine, in particular to ensure that trips, speed and load controls work properly. If there are different control stations e.g. engine governor, alternator panel, control room DCS, it must be clear which system has control under any particular circumstance, and that controls do not conflict.

SECTION 5 ANCILLARY SYSTEMS & EQUIPMENT

CONTENTS : -

5.1 FUEL SYSTEMS

Fuel systems will usually be proprietary systems developed by the equipment vendor for the needs of their particular machine. For offshore applications the system will have to be tailored to the particular fuel(s) available, and the space available. Single-fuel systems are quite straightforward, the fuel must be available at the required pressure and temperature, to secure block valves. There must be a provision for venting or draining the fuel system, and purging to a safe place.

Dual-fuel systems are much more complex, particularly if there is the requirement to change fuels on load. This can be a relatively hazardous activity, as any release of fuel will find an immediate source of ignition. Also, any abrupt change in fuel flow could cause a drive trip, with the load transferring abruptly to other units. The design, maintenance and operating procedures for dual-fuel systems must be robust for safe and satisfactory operation.

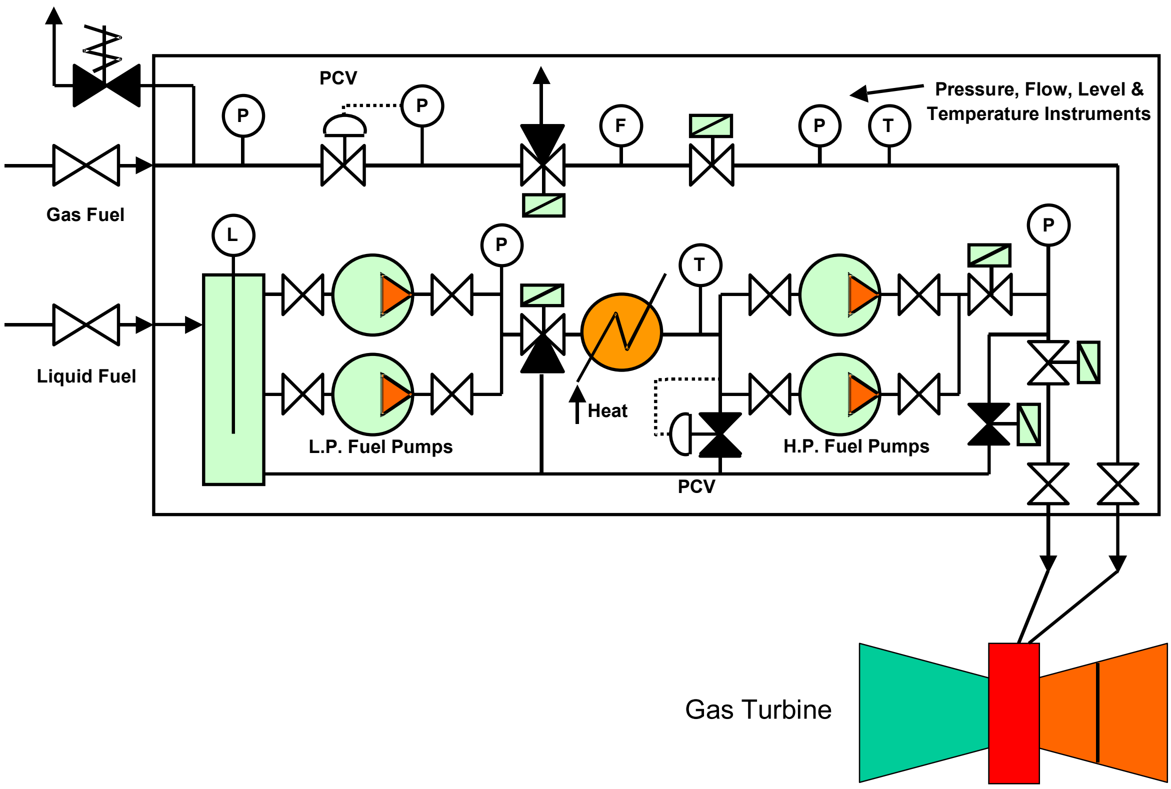


Figure 5 – 1 Gas Turbine Dual-Fuel System Schematic

5.1.1 Gas Fuel System for Gas Turbine

The basic gas fuel supply system for a gas turbine is a simple letdown, isolation and vent facility. It may have built in facilities for filtration, liquid removal (water or gas liquids), and nitrogen purging, depending on the requirements of the installation. The system frequently is trace heated and lagged to avoid liquid drop out during periods of shut down.

The primary purpose of the system is to provide fuel at the correct pressure and an adequate flow, when and only when required to do so by the control system on the turbine. The secondary purpose is to isolate the gas supply when it is not required, and to depressurise the outlet lines. Vent gas is piped to flare.

The main hazard associated with the Fuel Gas System is a gas release resulting in a fire / explosion. Hence as much as possible of the system should be located in well-ventilated locations with gas detector coverage. Elements located within the Gas Turbine Acoustic Enclosure rely upon the ventilation & safety systems within the enclosure. Work on any part of the fuel system should be avoided with the turbine running, if this is not possible then stringent controls are required. Any flange, joint or cover forming part of the fuel system containment should be part of a formal integrity check system, operated prior to re-pressurising the system.

The flexible pipework to the burners is particularly critical because it is after the last isolation valve and thus difficult to test. It is also in a hot location, subject to vibration and any fuel release is almost certain to find an ignition source. For this reason this pipework is often formed of double-walled steel pipe, with the capability to monitor the annulus between the two pipe walls. The remaining area of risk is the terminating flanges, work on these flanges must be to the most stringent standards, with witnessed checking.

A secondary hazard is the potential to supply fuel either when not required, or at too high or low pressure. This could cause a range of problems from unstable operation to an explosion inside the turbine. Hence the pressure control and isolation valves must operate correctly and provide effective isolation. The system must trip if inappropriate gas pressures are detected.

The operating instructions must cover the requirements for operating with all sequence links and vent routes in commission, and clearly spell out any occasions when it is permissible to operate with parts of the system disabled.

5.1.2 Liquid Fuel System for Gas Turbine

The liquid fuel supply system for a gas turbine receives, cleans and boosts the pressure of the fuel. It provides secure shut-off, draining and purging. It will have built in facilities for filtration, water removal, and nitrogen purging, depending on the requirements of the installation. The system frequently is trace heated and lagged to avoid waxing or water drop out during periods of shut down.

The primary purpose of the system is to provide fuel at the correct pressure and an adequate flow, when and only when required to do so by the control system on the turbine. The secondary purpose is to isolate the fuel supply when it is not required, and to drain and purge the outlet lines.

Gas turbines require liquid fuel at high pressure to suit the combustion pressure. The filtration is to remove fine solids which can otherwise erode the nozzles. Finely suspended water can be burned but can collect in dead legs and promote corrosion. Slugs of water can cause erratic combustion and difficult starting. For this reason, water is removed using special coalescer filters.

The main hazard associated with the Liquid Fuel System is a high pressure fuel release resulting in a fire / explosion. Hence as much as possible of the system should be located in well-ventilated locations with gas and fire detector coverage. Elements located within the Gas Turbine Acoustic Enclosure rely upon the ventilation & safety systems within the enclosure. Work on any part of the fuel system should be avoided with the turbine running, if this is not possible then stringent controls are required. Any flange, joint or cover forming part of the fuel system containment should be part of a formal integrity check system, operated prior to re-pressurising the system.

The flexible pipework to the burners is particularly critical because it is after the last isolation valve and thus difficult to test. It is also in a hot location, subject to vibration and any fuel release is almost certain to find an ignition source. For this reason this pipework is often formed of double-walled steel pipe, with the capability to monitor the annulus between the two pipe walls. The remaining area of risk is the terminating flanges, work on these flanges must be to the most stringent standards, with witnessed checking.

A secondary hazard is the potential to supply fuel either when not required, or at too high or low pressure. This could cause a range of problems from unstable operation to an explosion inside the turbine. Hence the pressure control and isolation valves must operate correctly and provide effective isolation. The system must trip if inappropriate pressures or flows are detected.

The operating instructions must cover the requirements for operating with all sequence links and drain routes in commission, and clearly spell out any occasions when it is permissible to operate with parts of the system disabled.

The parts of the fuel system located outside the acoustic enclosure are safely accessible with the gas turbine in service. Any fuel release or spillage should be contained, and will not be drawn into the turbine. There should be no sources of ignition in the area. For aero-derivative gas turbines, there should be no access to any parts of the fuel system located inside the enclosure with the turbine in service. Such components are thus remote and cannot be inspected, adjusted or operated. For industrial gas turbines, significant parts of the fuel system may be located inside the enclosure, which really serves as a turbine house. In this case, operators require access inside the enclosure with the turbine in service. This is potentially hazardous, and such access should be reduced to the essential minimum. In particular, starting up, shutting down, and fuel change-over are high risk activities; it would be good practice to modify equipment and procedures to permit these activities to be carried out remotely.

For either design of gas turbine, the design of the ventilation air flow inside the enclosure, with all the access doors closed, contributes greatly to the safety or otherwise of the turbine in the event of a fuel release inside the enclosure. The risk of explosion is greatly reduced if the release is drawn away from hot surfaces, towards gas detectors and is then diluted below the L.E.L . before being vented.

5.1.3 Fuel System for Diesel Engine

The liquid fuel supply system for a diesel receives, cleans and boosts the pressure of the fuel. It provides secure shut-off, draining and purging. It will have built in facilities for filtration & water removal. The system may be trace heated and lagged to avoid waxing or water drop out during periods of shut down. Lagging should be treated with care as it readily soaks up spilled fuel.

The primary purpose of the system is to provide clean fuel at the correct pressure to the fuel injectors. The secondary purpose is to isolate the fuel supply when it is not required. Standard practice for industrial engines is to have a low pressure pump providing a continuous supply of fuel to the engine-mounted high-pressure injection pump. The injection pump provides precisely timed pulses of fuel to each injector, as required by the engine. The engine is normally stopped by the injector pump stroke reducing to zero.

Diesel engines require liquid fuel at high pressure to achieve correct atomisation at the injectors. The filtration is to remove fine solids which can otherwise erode or block the injectors. Finely suspended water can be burned but can collect in dead legs and promote corrosion. Slugs of water can cause erratic combustion and difficult starting. For this reason, water is removed using special coalescer filters. Air locks can prevent engine starting. This is particularly important on emergency or standby equipment, which should have automatic venting to sealed drain. Manual fuel venting should be avoided.

The main hazard associated with the Liquid Fuel System is a high pressure fuel release resulting in a fire / explosion. Since the only high pressure pipework is from the injector pump to the engine, the rate of release will be relatively small. Good design should minimise the risk of spray onto hot manifolds, and collect any release or spillage into a tray with liquid detection and a drain provision. The low pressure pipework is less critical, the pressure should not be great enough to produce an atomised jet. The pipework should still be located so as to permit convenient inspection. There is always the potential to spill fuel when changing and cleaning filters, there should be provision to drain as much fuel as possible, and drip trays should be installed.

A secondary hazard is the potential to supply fuel either when not required, or at too high or low pressure. The low pressure fuel manifold will typically have a pressure regulating valve. The injector pump delivers directly to each injector, no relief is required. The system must trip if inappropriate pressures or flows are detected.

The fuel system is proprietary and much of it will be close-mounted on the engine. There will be very limited scope either for modifications/ improvements, or for safe access with the engine running. Since diesel engines are not suitable for extended continuous operation, periodic maintenance and inspections of the fuel system should be planned into routine engine servicing intervals.

5.2 LUBRICATION OIL SYSTEMS

Lubricating Oil Systems supplied as part of packaged equipment are a packaged sub unit of the equipment. The system will provide oil to act as lubricant to bearings and wearing surfaces which may in particular cases provide a buffer fluid for seals (see **Section 5.3**).

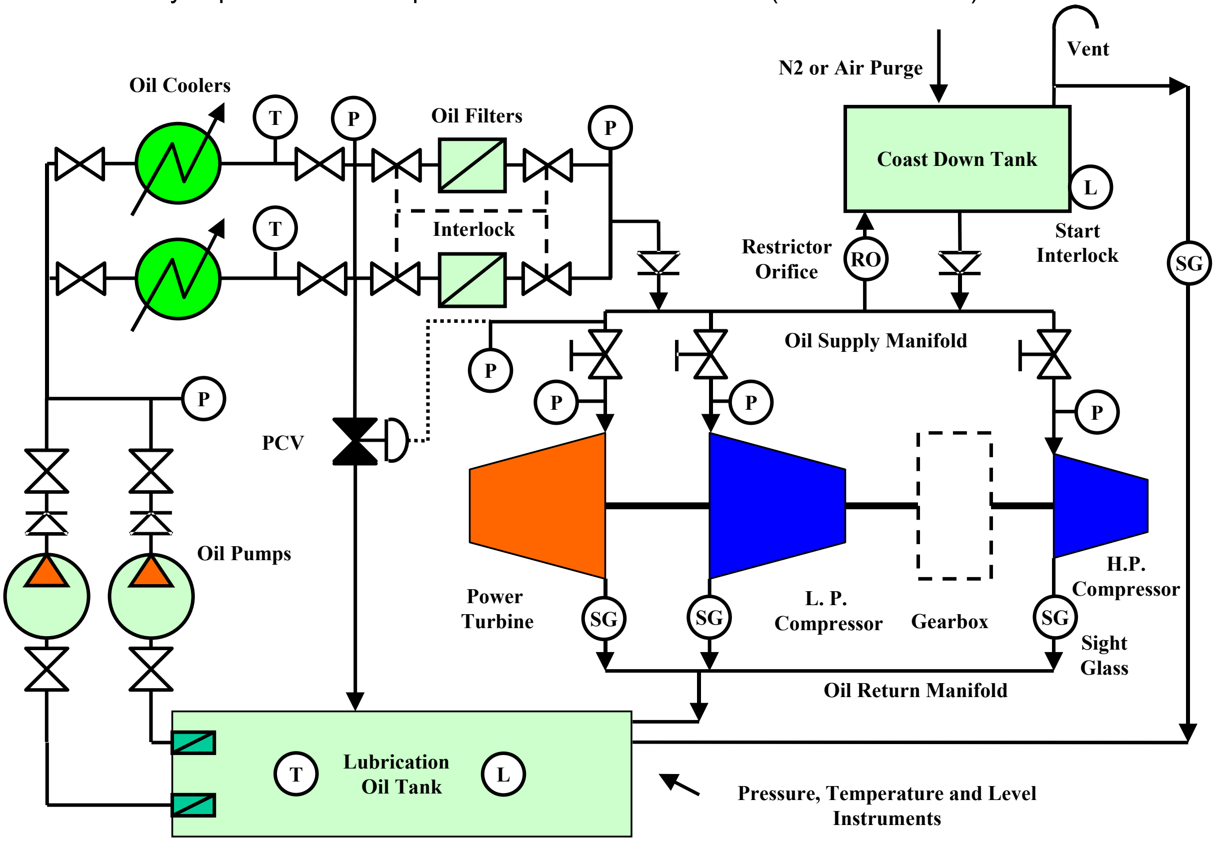


Figure 5 – 2 Process Schematic Diagram – Power Turbine / Gas Compressor Lubrication System

The supply of oil needs to maintain lubrication during all stages of machine operation, normal running, start up, shutdown, and failure.

The above diagram is a typical lubrication system for a large machine package. It has duplicate oil pumps, filters and coolers and a run down tank. The pumps should be powered from independent sources; e.g. separate electric supplies or one electric pump and one shaft driven pump. The oil tank operates at atmospheric pressure, this atmosphere could easily be contaminated with process gases / vapours or atmospheric moisture. For this reason it is good practice to purge the oil tank with a small flow of air or nitrogen. Nitrogen would be chosen to prevent a possible flammable or corrosive atmosphere, but then poses an asphyxiation risk on tank entry. One pump, one cooler, one filter would normally be in operation, with controlled changeover as required. Offshore, all parts of the system in contact with the oil should be in Stainless Steel. Onshore, it is common to use Carbon Steel or Epoxy lined Carbon Steel, upstream of the filters, and Stainless Steel thereafter.

Oil pressure is regulated to maintain the correct supply manifold pressure, and excess cooled oil is returned to the tank. Prior to machine start, the oil pump is started, which fills the Coast Down (or Run Down) Tank (if fitted). When the tank is full, excess oil overflows at a slow rate to prevent stagnation, a level switch providing a "run permit" signal to the Machine Train. In the

event of complete loss of oil supply, the Machine Train must be tripped, and the Coast Down Tank then provides enough oil to supply the bearings until the train stops. Note that the Coast Down oil supply rate is not enough to supply the bearings under full process load. Small units may use a hydraulic accumulator as a substitute for the Coast Down Tank. It is common to heat the oil tank to about 40 C prior to start, and to arrange for the normal tank temperature to be 40 – 50 C. This keeps the oil viscosity in the correct range, and prevents moisture condensation.

The oil system may have its own simple logic control, or be managed within the Package Control. Start-up & Shutdown sequences should be automatic and alarms / trips based on excursions of pressure, level and temperature. Changes to / operating out of sequence should be subject to a formal change control process.

Oil quality, temperature and pressure are all key parameters for successful machine & rotating equipment operation. This is particularly so when tilting-pad bearings are running at maximum load (usually this is at maximum shaft power). Oil temperature and pressure are continuously controlled and monitored, quality is checked by periodic sampling e.g. at monthly intervals. It is appropriate to test for water, metals (steel from gears, shafts, ball bearings: white metals from plain bearings: aluminium from labyrinth seals, copper from cooler tube corrosion), chlorides (indicates cooling water leakage), and process gas contaminants. At longer intervals it is appropriate to test the condition of the additives within the oil, and these can be topped up to maintain the condition. On a "clean" duty e.g. where the oil does not come into contact with process or combustion gases, it should seldom if ever be necessary to change the oil. Topping up should be with the same oil grade from the same supplier. Mixing of "equivalent" grades can give problems with incompatible additives.

Large machine bearings are normally continuously fed with oil, and some have a small internal reservoir for starting purposes. The return oil carries away the bearing heat, normally by gravity flow to the oil tank. Return pipes are thus often subject to 2-phase flow, which frequently puts the bearing housing under slight vacuum. If the bearing housing has good labyrinth or lip seals, a very small intake of the surrounding air will result. This is normally satisfactory, unless the oil seal area is subject to leaking process gas. A damaged oil seal will draw in excess air, probably bringing in corrosive moisture. A greatly excessive oil supply (probably caused by the trim valve having been left wide open) or problems with back pressure in the oil return lines, can result in oil leakage outward from the bearing. Oil seals are not designed to cope with being flooded, and will pass. Telltale oil dribbles point to oil level problems, and replacing the seal will give temporary relief only.

Oil storage should be well managed; opened containers should be mounted above containment trays, and re-closed after use. Oil labelling and handling procedures should cover oil management, hygiene, spillage, and avoidance of contamination, use of correct containers. There should be system in place for disposing of dirty, used or contaminated oils, with determination whether the waste oil is suitable to be processed through the installation's hazardous drain system.

Major Machines

The oil pumps may be driven by electrical power or by a combination of electrical and shaft drives. For an electric motor driven compressor, one working and one standby electrically driven oil pump would be logical. However, this arrangement requires an oil accumulator to hold oil at pressure or height, to support machine run-down in the event of power failure. It is common vendor practice to offer one shaft driven pump and one electrically driven pump. This provides for start-up, running, pump faults and run-down, without requiring a Coast Down Tank or accumulator. However, a fault on the shaft driven pump requires a machine stop to repair, and it is not good practice to run on a single pump. The other drawback is that if the shaft driven pump fails without warning, the machine bearings will be badly damaged if the standby pump fails to start automatically. Power requirements for control valves and other instruments must be considered, a UPS system may be required. As the package lubrication system will be very congested, and fairly inaccessible, oil leaks from pump seals or pipe joints will be difficult to

detect and repair. The use of drip / drain trays and the least possible number of screwed fittings is advised.

Where a common lubrication system is fitted, in particular one which also provides compressor seal oil, there is a real issue of potential cross-contamination of the oil. The heavier fractions of hydrocarbon gases can dissolve in oil, reducing its viscosity and increasing its flammability. The fire hazard associated with this potential problem will be greatly reduced if the oil system operates under a nitrogen atmosphere.

The most serious issues for the supply of oil to a machine package arise from either failure of the supply that can lead to damage of the machines, or from oil spill or leakage resulting in a fuel source for potential fires.

Two machines in duty/ standby configuration must never have linked or shared lubrication systems as this invites common mode failure and a complete shutdown.

For Reciprocating Compressors

If the piston rod seals and vents are not working properly, hydrocarbon gas can enter the crankcase. Avoidance of such cross contamination is essential and the design of the machine will include dual chambers between the cylinder head and the crankcase to isolate leakage from the cylinder gland and the crankcase. (see **Section 4.4**)

Minor Machines

The oil pumps may be driven by electrical power or by auxiliary drives from the turbine. Electrical drives are much simpler and make pump location much easier. Where the installation has reliable electrical supplies this option would be preferred. If the package is required to operate in "stand-alone" manner even after a total electrical failure, then shaft drives are required. Power requirements for control valves and other instruments must be considered, an UPS system may be required. As the package lubrication system will be very congested, and fairly inaccessible, oil leaks from pump seals or pipe joints will be difficult to detect and repair. The use of drip / drain trays and the least possible number of screwed fittings is advised.

Where a common lubrication system is fitted, in particular one which also provides pump seal oil, there is a real issue of potential cross-contamination of the oil. Liquid fuel or the heavier fractions of hydrocarbon gases can dissolve in oil, reducing its viscosity and increasing its flammability. The fire hazard associated with this potential problem will be greatly reduced if the oil system operates under a nitrogen atmosphere.

Hazards Associated with Lubrication Systems

The most serious issues for the supply of oil to a machine package arise from either failure of the supply that can lead to damage of the machines, or from oil spill or leakage resulting in a fuel source for potential fires.

Oil spillage / release around the lubrication skid poses personnel slip / trip hazards, in addition to concerns about pollution. If the spilled oil could run or drip onto other systems, it could pose a hazard remote from the oil system.

Cold lubricating oil does not readily ignite in air, even as a fine spray, which might result from a pinhole. Oil soaked into hot lagging is much easier to ignite, with the combination of increased temperature and large surface area. Burning lagging is not a major fire but is difficult to extinguish. Oil dripped or in particular sprayed on to high temperature ducting / casings, is very likely to ignite. Note that good ventilation will increase the severity and spread of such a fire. Hence oil supply pipework in known hot areas (e.g. gas turbine exhaust end bearing) should be designed with minimum joints, routed clear of hot surfaces, possibly put behind shields or

provided with some form of double containment. After any invasive work, leak checking / joint inspection should be carried out. Thermal expansion might create leaks on poor joints.

In the event of a major machine fire, it is quite likely that oil supply lines will be damaged. Hence the oil supply should be stopped in the event of a fire. Hazard studies should identify if remote isolation valves should block off bearing feeds (and Run down Tank) even before the Machine Train stops.

The Lubrication Oil Tank and pumps should be covered by the relevant Fire & Gas System, with detection and fire fighting arrangements. Oil tanks should be appropriately protected from the build up of static electricity with electrical continuity connections provided to give earthing of the components.

5.3 SEALS & SEALING SYSTEMS

5.3.1 Static Seals

Static sealing in effect comprises all non-welded joints between static components forming the pressure envelope. In order to prevent (or in some cases limit) the leakage of process fluids, a softer material is normally clamped between machined faces on the two major components. There are a few good principles that define a good static seal design: -

- The fully clamped joint forms a metal-to-metal fit enclosing the softer joint material. This controls alignment, joint compression and greatly limits the release rate should the seal fail.

- The joint component is of a material that is suitable for the temperature, pressure and chemistry involved. Typical examples are given below.

- The clamping force on the joint is controllable, and the pre-load is sufficient to keep the joint closed under all process conditions.

- On very critical joints, the clamping force can be monitored.

- Where it is necessary to replace the joint without affecting equipment alignment, this can be done without disturbing the pipework (normal pipe flange joints are an example)

- Failure of a single joint will not permit incompatible fluids to mix (e.g. cooling water and lubricating oil.

- Tapered screw threads cannot produce a highly reliable joint, parallel threaded pipe connections can do so in conjunction with e.g. Dowty seals.

Typical examples of joints are: -

- "CAF" (now non-asbestos replacements). Suitable for low-hazard service only as the fibre joint can fail and be blown out. (Older installations may still have original CAF jointing which will require to be properly handled and disposed of.)

- PTFE envelop joints. PTFE, providing chemical resistance, is wrapped around a metal core to provide mechanical strength.

- "Metaflex" and Graphite based systems provide high temperature pipe joints.

- "O" rings are very good for machine component joints where machined grooves can be provided. A wide range of elastomers, or PTFE wrapped elastomers, are available.

- Extreme temperature machine joints can be sealed by tubular metal "O" rings. These are expensive and easily damaged in handling.

- Seals tolerant of intermittent rotary or sliding motion include "O" and "X" ring designs in appropriate elastomers. These require some form of lubrication.

Seals/ gaskets should be stored flat, larger sizes should be supported e.g. by card. Many seal types have a shelf life, and this should be managed by stock rotation, with beyond-date items disposed of. Seals should be handled with care to avoid damage, "O" and "X" rings often require mandrels or ramps to aid fitting. Some gaskets have very sharp metal edges.

The primary hazard relating to seals is mechanical failure, with consequential release of flammable / toxic material. Significant leakage is mostly caused by incorrect assembly or bolt tightening. Another known cause is the substitution of non-standard gaskets within the seal.

PTFE which has been subject to high temperatures (perhaps 300 C +) can generate hydrofluoric acid. Hence PTFE should never be used on high temperature ducting, and singed or fire-damaged equipment treated as HF-contaminated.

All joints on process equipment, and hydrocarbon pipework, should be made by competent people using the appropriate tools. Joints should be tightened progressively and in a planned sequence. Systems that measure the bolt extension a s measure of pre-load are preferred to torque measurement alone.

Low-pressure leak testing on inert gas is advised prior to introduction of process gas. Hydraulic testing does not provide good leak detection on gas systems, and can put liquid in inconvenient places, providing a source of future corrosion.

5.3.2 Labyrinth Seals

Labyrinth seals are used to provide non-contacting shaft seals typically as interstage seals on gas compressors. Simple labyrinth seals also perform well as oil seals. The principle is a rotating sleeve inside a static sleeve. There is a small radial clearance, a series of steps or grooves provide a series of pressure breakers, restricting the leakage flow. As the seals do not contact, they require no lubrication and generate negligible heat. It is normal to make one component out of a soft metal, e.g. aluminium, which then wears away if the seal rubs.

Labyrinth seals are often allowed to float radially, and self-centre during machine start. If the seal is stuck and cannot float, it will wear away. In certain atmospheres, a metal like aluminium can fire if sufficiently heated by such a rub. The seal will then be destroyed, altering the internal pressure balance of the machine. This may then cause bearing problems or excessive vent flows.

Labyrinth seals often have a limited tolerance to axial shaft movement. In this case it is important that the cold set position is close to one end, designed so that the differential thermal expansion is within the working range of the seal. This may well mean a time-controlled warm-up or load-up on the machine. Bringing the machine on line too quickly may thus cause permanent seal damage.

5.3.3 Mechanical Sealing Systems

For the purposes of these notes, the term "mechanical seal" will apply to seals using a liquid barrier medium, either the process fluid or a separate flush liquid. Seals using gas as the barrier medium are covered in **Section 5.3.4**. All mechanical seals work on the principle of having 2 finely machined rings working as a matched pair. One ring is linked and sealed to, and rotates with, the rotating equipment shaft. The other ring is linked and sealed to the housing, and does not rotate. The adjacent axial faces of the rings are flat, the gap between the rings should be controlled to a few microns by permitting a tiny flow of the barrier medium to act as a sealant, lubricant and coolant. If the barrier medium is not present under the correct conditions, and the rings are allowed to touch, wear will occur and the seal may destroy itself.

The simplest form of mechanical seal is the single seal, here one pair of rings provides a single stage barrier to leakage. The process fluid acts as the barrier fluid, a tiny flow of liquid crosses the seal faces, normally to evaporate into the surroundings. Hence a correctly working single mechanical seal leaks continuously, but should not be producing visible liquid. For this technology to work, the fluid must be present at, typically, 1 – 5 bar above the local environment pressure. This provides the driving force to push the fluid across the faces. The fluid must be

clean, and have a viscosity in the range, typically, of 0.5 – 100 cP. The hydraulic design of the equipment must ensure the presence of clean, cool fluid at the seal faces. This is often achieved using external flush pipes, which are vulnerable to damage and thus leakage. Good modern designs have open seal areas with natural fluid circulation and no small bore drillings or pipes. Fluids containing dirt or salts will evaporate in the seal, leaving behind abrasive solids. These can damage the seal faces, and/ or force the seal faces apart, causing excessive leakage.

If the fluid being handled is toxic or flammable, the environment just outside the seal could well contain a vapour concentration which is above safe limits. This is particularly true with hot materials and if the seal is failing. It is difficult to monitor the leakage rate from a single seal, although vent/ drain pipes and correctly located gas detectors can help.

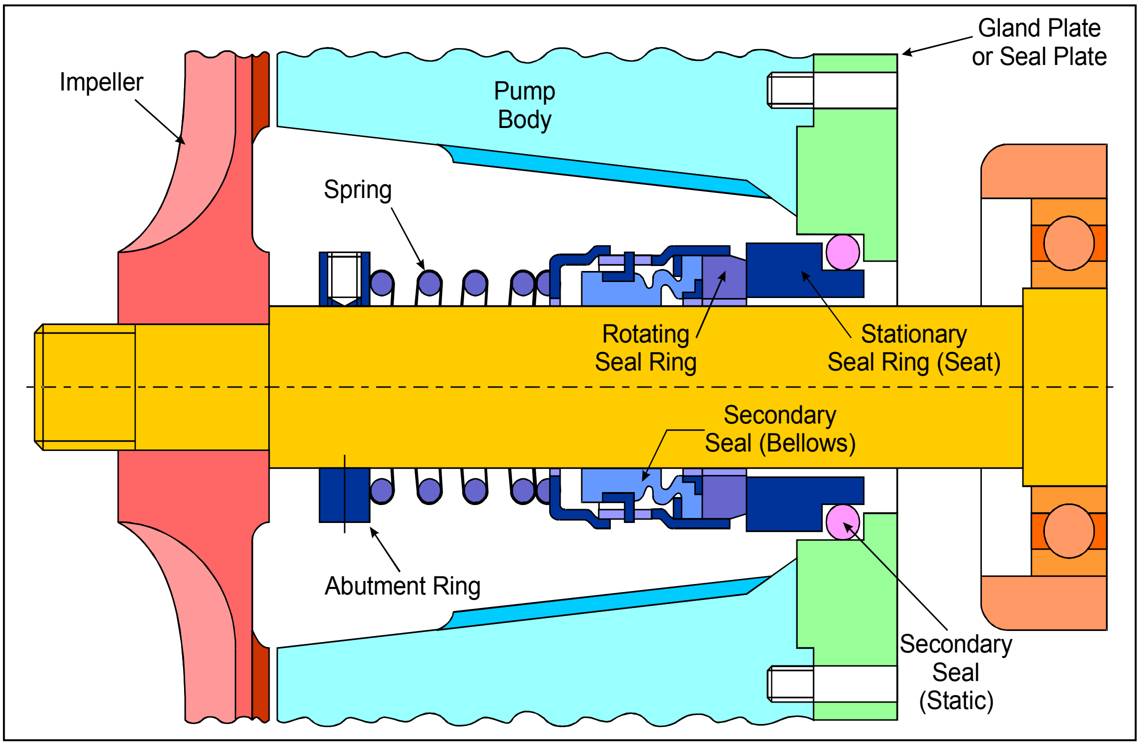


Figure 5 – 3 Single Mechanical Seal in Centrifugal Pump

Where a single seal will not work, or is considered to be not secure enough, two seals are fitted to work together. There are two different ways in which this can be done, the difference is significant and cannot be readily checked by observation only :-

The term "Double Seal" should be used when pair of seals work together, with the barrier fluid pressure higher than either the process fluid pressure or the atmospheric pressure. Thus the barrier fluid should always leak to process and to atmosphere. Provided that the barrier fluid pressure remains high, no process fluid can leak to atmosphere. Thus by monitoring the barrier pressure, the operators can be assured that the process fluid is being contained. By monitoring the flow or level of the barrier fluid, the rate of leak can be measured, thus the condition of the seals is monitored. In order to use double seals, some leakage of barrier fluid into the process must be acceptable.

Normally, double seals use a small service unit to circulate pressurised and cooled barrier fluid to each seal. These service units add significantly to the cost of the installation, particularly for split casing and barrel casing pumps which have two sealing locations on the shaft, each of which requires service. Shared service units have generally proved to be unsatisfactory.

Monitoring of fluid pressure, level, temperature and flow, as appropriate, is usually done on the service unit. The connecting pipework for the service unit is small bore and vulnerable to damage, particularly as the final connection to the seal is almost invariably a small screwed fitting. The pump design, and the need to remove the seal for service, often precludes a robust welded or flanged connection.

There is a particular type of service unit, often used on agitators fitted with double mechanical seals, which uses a small pump to circulate fluid from a reservoir, to the seal, and back to the pump. With this design, if the pump fails, the fluid pressure drops to the reservoir pressure, which is ambient. Many mechanical seal designed cannot tolerate reverse pressure of more than perhaps 1 barg and will open, allowing process fluid (or gas from an agitator) to flow back to the reservoir. Since these reservoirs are open vented, there will be a release to atmosphere. There is a protective measure using solenoid valves and a drive trip, but it is not an ideal solution and these units are not really suitable for hazardous locations. The preferred solution is a fully sealed unit with a Nitrogen pressure charge.

The term "Tandem" is used when pair of seals work together, with the barrier fluid pressure lower than the process fluid pressure but above atmospheric pressure. Thus the process fluid will normally leak into the barrier fluid, and the barrier fluid (with some process contamination) will leak to atmosphere. Provided that the rates of leakage are low, the rate of leakage to atmosphere is acceptable. For light hydrocarbons, if the barrier fluid is circulated to a vented vessel, and the vent is to flare or safe location, this can be a simple, robust and acceptable system. By monitoring the barrier fluid level, the operators can be assured that the leakage rate is under control.

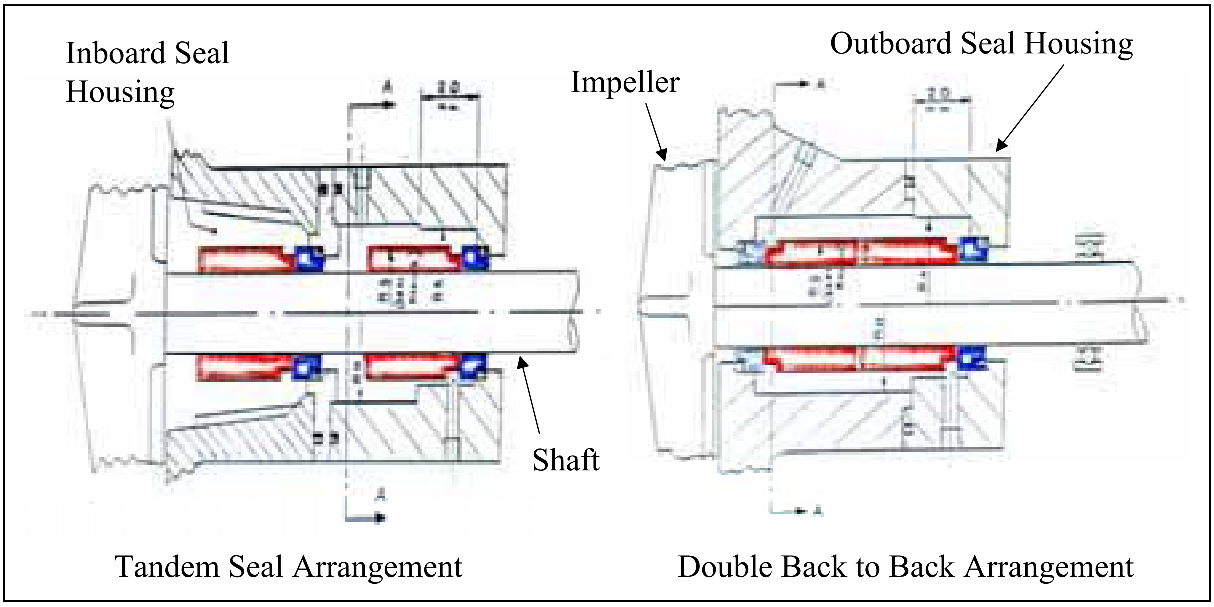


Figure 5 – 4 Tandem & Double Mechanical Seals in Centrifugal Pump

The mechanical arrangement of the sealing faces is very specialised and is proprietary technology. The basic arrangement is to have one seal ring, normally the static one, fixed in space, at right angles to the shaft centre line. This seal ring is referred to as the "seat" , and is sealed to the housing by an "O" ring or gasket. As the seal seat is manufactured to have a very flat face, and is often made of brittle materials, it is very important that the mounting and sealing system imposed low and even loadings on the seat. The mating rotating ring, known as the "face", is then located on, and driven by, the shaft. In order for the seal to work the face must be located radially, but free to float axially and free to rock sufficiently to seal. It must also be sealed to the shaft to prevent bypass leakage. This "soft" secondary seal can be very sophisticated and is part of the key to the seal's design and success. The seal seat is typically made of very hard, thermally stable material, for example Silicon Carbide. It should have high

thermal conductivity to remove heat. The mating face is usually of a resin bonded carbon material, which is lapped on to the seat, and has some degree of self lubrication to cope with brief dry running or vapour locking. For special duties, e.g. slurries, the face is also of Silicon Carbide, but such seals are intolerant to even brief dry running, hydraulic shock or impacts. The secondary seal may be a simple elastomer "O" ring, or a bellows made of elastomer, PTFE or metal. The seal will contain a spring, or use the inherent springiness of the bellows. The seal is then designed such that the fluid pressure difference + the spring load is sufficient to keep the faces together, floating on a fluid film, but that the faces do not grind together and overheat. The heat generated by the seal is removed by conduction, and by cooling the sealing fluid.

As mentioned above, in double seals the service pressure is maintained higher than the service pressure in order to keep the seal faces closed. If the service pressure is lost, the process pressure is often sufficient to overcome the spring pressure and the seal will open and leak. There is a special design of mechanical seal which is designed to withstand such pressure reversals without leaking. The cooling effect is, however, lost and the drive should be stopped immediately.

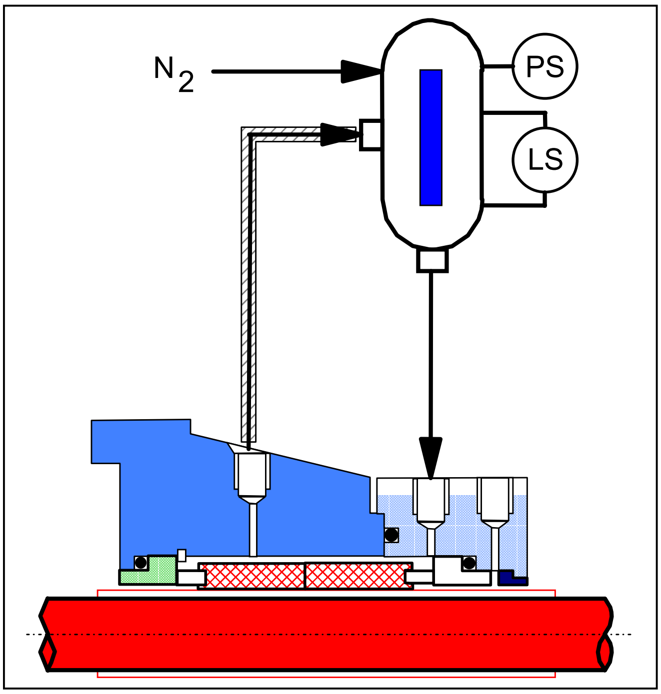


Figure 5 – 5 Double Seal with Thermosyphon Barrier Fluid System

Mechanical seals contain mobile seals, thin gauge metal parts, springs and brittle materials. As such, it has to be accepted that they can fail without prior warning, and release the process through a gap equivalent to the radial clearance between robust parts of the seal. Even double and tandem seals, although they reduce the risk of coincident failure of both, have some common mode failure mechanisms (e.g. bearing failure). It is good practice to have a non-wearing, simple and robust secondary seal. This can be provided in the form of a throttle bush, which is a static bush made of PTFE, bronze or brass, with a radial clearance of typically 0.5 mm to the shaft. The choice of materials is avoid corrosion or shaft damage, and the leakage rate is significantly reduced. Vendors offer proprietary secondary seals, but these generally are variants of lip or floating seals, and are not robust. The best possible secondary seal is possibly a throttle bush followed by a proprietary seal, with the interspace connected to a reasonably large drain pipe. This should drain the vast majority of the release to a safe area.

Seal failures are less common on new equipment with factory build quality and build cleanliness, partly because mechanical seals are difficult to install well under field conditions. This is particularly true of double seals, which require alignment and distance setting in a very confined space. Most mechanical seals are now available in a cartridge format, where most of the assembly and distance setting has been done under factory conditions. Where double seals are required, it is good practice to insist on the use of cartridge seals. If the bearings or shaft of a pump are worn or damaged, then more frequent seal failures can be expected. Some duties e.g. light hydrocarbons, high temperatures, high suction pressures, are particularly hard on seals and require very good seal selection and system design. Chemical industry practice is to use canned motor pumps, where possible, for such difficult duties.

For double and tandem seals, it is crucial that the appropriate monitoring is in place on the seal service unit, with alarms and trips as appropriate. Cooling may be naturally to air or via water-cooled coils. It is usually necessary to circulate the barrier fluid, this is ideally by means of a pumping ring built into the seal, or by a small canned motor pump. Natural circulation systems using a thermo-syphon are offered, but often do not work. For them to work properly normally requires an unlagged vertical (hot) pipe at least 1 metre long, which then typically puts the header vessel too high up for convenient access.

Useful Publications :-

I.Mech.E publication "Mechanical Seal Practice for Improved Performance" (edited by J.D. Summers-Smith)
Seals and Sealing Handbook (2nd. edition 1986). The Trade and Technical Press Ltd.
ISBN 85461-10-0
The Seal Users Handbook. R.M. Austin & B.S. Nau (BHRA Fluid Engineering)
ISBN 0 900983 337.

5.3.4 Dry Gas Sealing Systems

Application of Dry Gas Seals

Dry Gas (or Gas Barrier) seals are new technology and are not common offshore. The initial applications were for high speed gas compressors although there are now some pump applications. Dry gas seals absorb less power and generate less heat than liquid barrier seals. They also require a simpler, lighter, barrier fluid system. Typically, the stage sealing and balancing within the compressor or pump is done using the process fluid. The actual mechanical seal, which is almost always a double seal, uses a small amount of barrier gas. The applications may be limited by the availability of barrier gas, and by the consideration that a there is a small flow of barrier gas into the process.

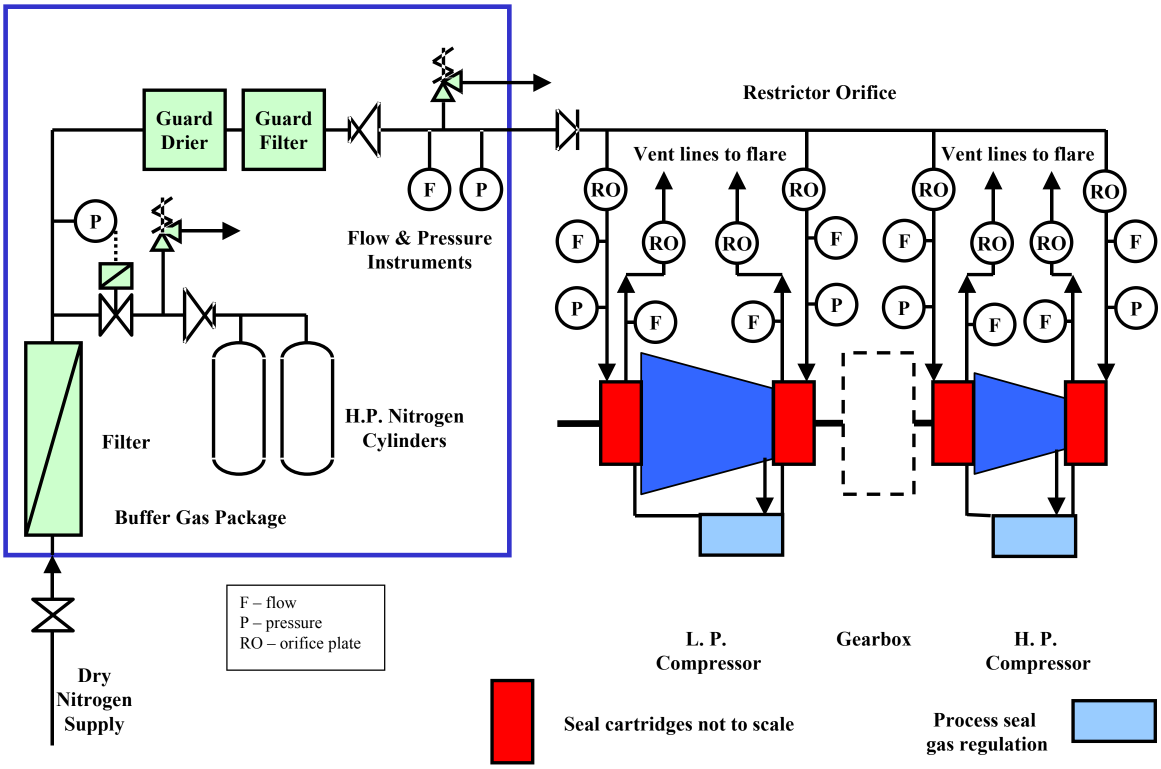


Figure 5 – 6 Process Schematic Diagram – Dry Gas Seal System

Design of Dry Gas Seals for Centrifugal Compressor Applications (pump application is similar)

Dry Gas Seals are mechanical shaft seals that use inert gas (normally nitrogen) as the service fluid, rather than the liquid service used with conventional mechanical seals. Dry gas seals are normally installed as double cartridge seals ensuring correct assembly and alignment of the complex and finely engineered internals. The seals are dependent on a continuous supply of clean dry inert gas to maintain the correct face gap and cooling. This is normally at about 1 – 2 bar above the buffering pressure. As the external seal sees full service pressure, it is good compressor system design to arrange for the buffer gas pressure at the seal to be just above atmospheric pressure. This keeps the service pressure and thus the pressure on the external seal, to the lowest practical value. Sub-atmospheric internal pressures pose potential inward leakage problems. Seals require gas pressure prior to start-up; many designs are uni-directional and will be permanently damaged by reverse rotation.

The process side of the shaft seal is in contact with buffer gas, normally this is clean process gas at a controlled pressure, derived from the compressor and fed into labyrinth seals mounted just inboard of the shaft seal. If inert gas is not available, it is technically possible to use clean dry hydrocarbon gas as the gas seal service fluid. In normal service the gas loss rate is negligible, but if the external seal fails there will be a hydrocarbon release to atmosphere until the compressor and seal system are shut down and isolated. The Safety Case for the installation would have to justify such an arrangement.

The primary hazard from Dry Gas Sealing systems is the release of the process fluid (e.g. hydrocarbon gas) as a result of seal failure. Any dry gas seal will eventually wear out and start leaking, but normally the leak will be inert gas into compressor, or inert gas to atmosphere. As soon as the leakage rate exceeds the alert level, the seal monitoring system will alarm. Under these conditions no hydrocarbon will have been released to atmosphere.

A more serious event is mechanical damage to seal components, e.g. a broken seal face. This can be caused by mechanical or thermal shock or from pre-fitting damage or extended standstill periods. The rate of release will be limited by the narrow internal clearances.

The most serious event is a complete loss of containment, which can happen if the complete seal fails. Possible causes are shaft breakage, or axial movement of the complete seal and mounting assembly. Assessment of this risk requires knowledge of the complete compressor shaft mounting arrangement, and the method of seal mounting. Where failure of a single screw or fastener could permit shaft or seal movement, there is a clear risk.

For a more detailed study on dry gas seal systems see "Hydrocarbon Release – Dry Gas Seal Integrity Survey Report" ref. HSE Agreement No. D3819, prepared for the HSE by Neale Consulting Engineers Ltd.,

5.3.5 Oil Seals

Oil seals are used to prevent oil leakage from bearing housings. They also have an important role in minimising the ingress of air, dirt, and water from outside. Lip seals are commonly used, although these start as a contacting seal, the lips wear rapidly until the effect is at best a lubricated simple labyrinth seal. This will not usually hold standing oil (from inside) or projected water (from outside). More sophisticated labyrinth seals are available, these are much preferred where the environment outside the seal is hostile (wet, dirty, contaminated). Labyrinth seals are not fully effective on a stationary shaft, and some designs include a component that is supposed to close when the shaft stops.

The only real hazard is that of oil release, significant release is only likely if the seal is flooded. The seal will have no effect in a fire, as it will burn away.

5.4 ACOUSTIC ENCLOSURES & SILENCERS (including Ventilation, Fire / Gas Detection)

5.4.1 Purpose of Acoustic Enclosure

The primary purpose of an Acoustic Enclosure is to protect people outside the enclosure from the noise generated by equipment inside. Secondary purposes may include weather protection, containment / ducting for cooling & ventilating air. Two basic designs are used: -

- Close fitting enclosure. In this design there is insufficient room to work inside the enclosure, thus panels must be opened or removed to gain access. This would almost always require the machine to be shut down first. In some designs the whole enclosure is lifted away.

- Walk-in enclosure with a general gap of 600 – 1200 mm between equipment and enclosure wall. Access is via personnel doors; operator attention and much servicing can be done without removing panels. Major overhaul still requires panel removal.

Acoustic Enclosures are only normally installed around equipment which is inherently very noisy – typically Gas Turbines, Multistage Air Compressors, Screw Compressors, Large Fans. The equipment must be designed on the basis of having the enclosure, otherwise operator / servicing access may be severely compromised.

Air compressors and fans should not pose a particular hazard within the enclosure, although it will be hot & noisy. There must be effective means of escape, and entry should not be made in order to investigate a potentially dangerous condition. At noise levels greater than 85 dBA, personal hearing protection is recommended, and at above 90 dBA, mandatory. Strictly, these levels apply to continuous exposure over a working shift, but it is good practice to apply them to any visit to a noisy location, with noise levels increasing greatly close to the source such as the machine.

Gas Turbines pose a particular hazard by combining high-speed parts, high noise levels, potential for release of easily ignited fuel, and continuous sources of ignition. The safe design of the enclosure requires inputs at all levels, to: -

- Minimise the risk of a release.

- Maximise the likelihood of detecting a release and stopping further release.

- Diluting the release below the flammable limit.

- Preventing the gas from reaching a source of ignition.

- Mitigating the effects of an explosion (relief panels, etc.,)

- Preventing unnecessary access inside the enclosure, particularly during events known to carry a higher risk e.g. fuel changeover.

See HSE Guidance Note PM 84 "Control of safety risks at gas turbines used for power generation " and Draft Guidance Note " Control of safety risks at gas turbine driven CCGT & CHP plant ".

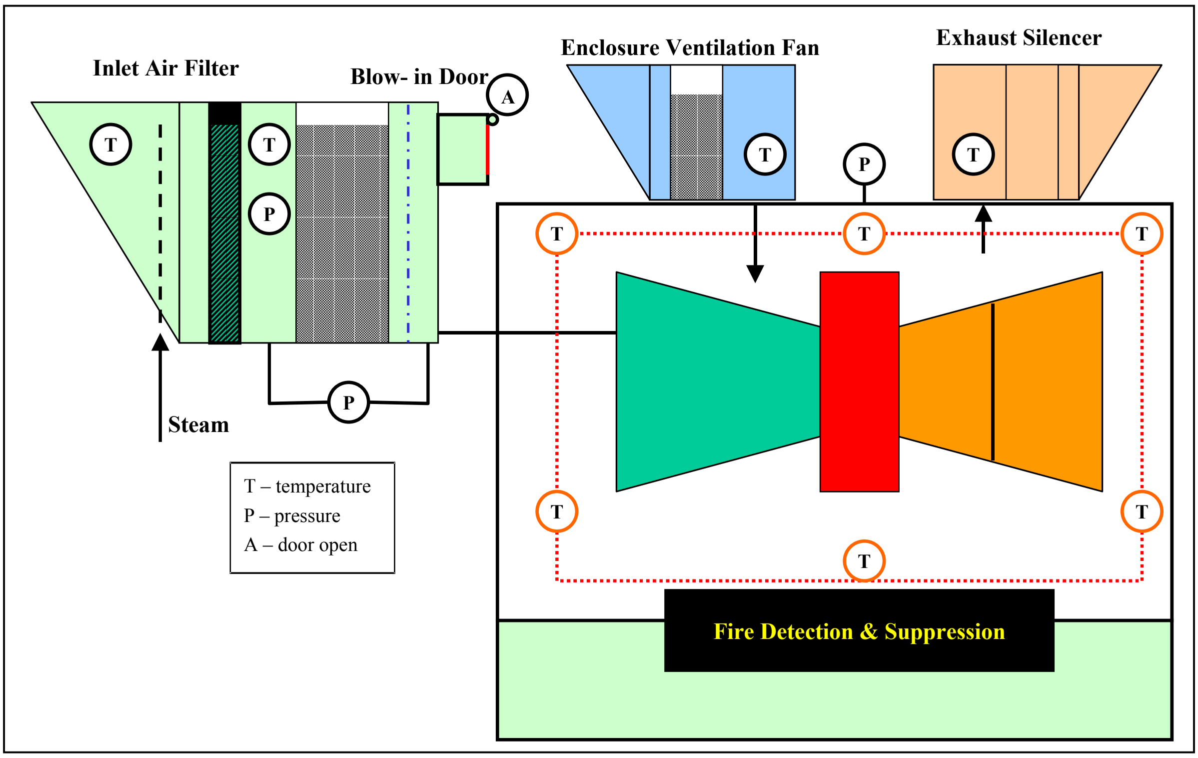


Figure 5 – 7 Process Schematic Diagram - Air Inlet , Acoustic Enclosure

5.4.2 Silencers

The air intake and exhaust from a gas turbine, the inlet & exhaust air from an acoustic enclosure, and many process gas streams, require silencers to control the breakout of machine noise. The design of silencers is a specialist activity, combining a pressure containment requirement with a noise reduction function.

Pressure containment will be dictated by the system design, gas line silencers will usually comprise pressure vessels with silencer internals, while air / exhaust system silencers operate at low pressure and usually require only sheet metal construction.

Machine noise, particularly from rotary machines, is normally controlled by absorption or splitter silencers, which have the necessary bandwidth. The air or gas flow is split into parallel channels, each of which is lined with perforated metal boxes filled with absorbent material. The material is usually mineral wool; this may be wrapped in polyester sheet to keep out moisture.

Silencers and ducts are inevitably subject to vibration, this can dramatically increase during start-up and load changes. Hence silencers may be subject to internal cracking, or failure of rivets. In the extreme the silencing material is lost or the flow partially or completely blocked. Downstream equipment may collect debris.

5.4.3 Ventilation Systems

Acoustic enclosure ventilation systems must provide cooling air, and dilute any gas releases as quickly as possible. This may pose apparently contradictory requirements. Air flow testing or Computational Flow Dynamics modelling may be required to assess the final design. The normal arrangement is multiple inlets via silencers, and multiple exhausts via fans and

silencers, to a safe place where any released gas will not pose a further hazard. Equally the intake must not be in a location which can suck in gas and should be fitted with gas detection.

Several ventilation fans should be used, powered from different sources. The total air flow must satisfy heat removal and dilution requirements. It may be appropriate to run only half of the installed ventilation fans, switch on the rest manually or automatically if a leak is detected.

The ventilation design must cope with open doors or access panels, if it is acceptable to operate the equipment under these conditions. Alarms or trips are required, based on air flow and / or temperature at key points in the enclosure. On loss of air flow, the enclosure must be evacuated and the equipment then shut down. Some designs may permit safe operation (but not access) under natural ventilation only.

5.4.4 Fire & Gas Systems

All locations where either a hydrocarbon gas release or a fire might reasonably be expected, should be covered by fire / gas monitors. These may be part of a whole-installation system or part of a package system, particularly if inside an acoustic enclosure. It is normal to place gas detectors close to potential leak points, and to exhaust points. However, the detectors must be reasonably accessible for inspection and testing. Gas is detected by its potential to react in air. Inert gases / non-flammable asphyxiants are not detected by this means. Fire may detected by heat, ionisation or ultra-violet emissions. A mix of sensors may be used according to need.

There has been some recent use of acoustic gas detectors. These can pin-point the leakage point and can detect flammable and non-flammable gases. They do not need to be in the gas/ air mixture but do need a clear sound path from the leak point to the detector.

All fire / gas systems must be co-ordinated at the control room, with the facility to assess a plot plan or similar to map the boundaries of a release or fire and plan its management.

Hazard studies should determine the need for automatic or manual links to shutdown systems, air dampers, and fire suppression systems. Provision must be made to disable any fire-suppression system covering an acoustic enclosure or enclosed space, if access is required.
Fire & gas systems require periodic calibration and testing.

5.5 GEARBOXES, HYDRAULIC DRIVES & COUPLINGS

5.5.1 Mechanical Gearboxes

Mechanical gearboxes transmit power between two shafts that are not co-axial, and are running at different speeds. The speed ratio of a mechanical gearbox is normally fixed. Parallel shafts are driven by spur gears with straight, helical or herringbone tooth arrangements, in order of increasing design tooth load. Shafts at right angles are driven by bevel gears or worm gears. Gearboxes often have multiple gear reductions (thus pairs of gears) in the same casing.

Gearshafts must be very accurately guided; this is done by rolling element or plain bearings according to shaft speed and load. Helical gears generate thrust loads that are taken out by internal thrust bearings or rings. Gearboxes are normally intended to accept only moderate external thrust loads. Bearings and gears will be lubricated by a common oil system, this may be a self-contained pumped or splash system, but on larger units will normally be shared with other machines or rotating equipment in the package.

Gearboxes should normally pose little hazard, as all moving parts will be enclosed or guarded. On higher power / higher speed units a failed gear could result in ejection of parts, with a significant release of lubricating oil over a wide area.

There might be a consequent risk from the loss of drive to the driven rotating equipment, or overspeed of a variable speed machine (driver) from sudden loss of load.

It is normal to fit flexible couplings to the input and output shafts of power gearboxes, to minimise transmission of axial or bending loads from shafts.

Gearboxes may require acoustic protection, and this can often be done with a lagging box. Gearboxes can emit oil vapour, and vents should be fitted with mist eliminator filters.

Typically, two types of gearbox are used :-

Parallel shaft gearbox, using helical or herring bone pattern gears to reduce the speed in one or two stages. This type of gearbox displaces the driven equipment laterally by typically 0.5 – 1 metre. It is easy to inspect and maintain, as the gearbox cover can be removed without disturbing the gear mesh. This type of gearbox is more likely to be used for reciprocating compressors.

Epicyclic gearboxes, which work on the "sun and planets" principle, have co-axial input and output shafts. Hence all machine shafts are in line, making alignment easier. Epicyclic gearboxes are also smaller, for a given power, than parallel shaft units. They have inspection covers, but full examination requires the gearbox to be removed and at least partially stripped.
There are a limited number of safety issues from inclusion of a gearbox within a machine package. The most serious are : -

> The potential for unplanned engagement of auxiliary drives, used to rotate the compressor at low speed, leading to massive overspeed and, usually, disintegration of the auxiliary drive.
> For bursting of the gear wheels (design or manufacturing flaws).
> For fires due to leakage of lubricating oil.

5.5.2 Hydraulic Gearboxes

Hydraulic gearboxes are one-piece drive units with an input and output shaft. The two shafts are not linked mechanically but use an internal positive displacement hydraulic pump / motor mechanism to transmit power. A characteristic of the units is that a fixed input shaft speed can be used to generate an output shaft speed of between zero and about 95 % of input shaft speed. At reduced speeds, the output torque can be much higher than the input torque. The units can vary speed on load and can often be made to go into reverse when on load. The operating principle is a positive displacement piston pump, directly driven by the input shaft, which feeds hydraulic oil into a manifold. The pump has a mechanically controlled variable displacement. The hydraulic oil drives a hydraulic motor mounted back-to-back with the pump. Hydraulic gearboxes are very compact, but often require oil coolers. Their particular merit is very quiet operation, continuously variable speed with good control and very little wear. They are much more efficient than hydraulic couplings for operating below about 70 % speed. The speed ratio varies with load thus for accurate control the output shaft speed must be measured.

Hydraulic gearboxes are not generally used for particularly high powers, the only real hazard results from overheating and the potential for and oil fire. On loss of oil the drive will fail and hence give operator warning.

5.5.3 Hydraulic Drives

Hydraulic drives comprise a hydraulic motor and hydraulic pump working as a pair, coupled by pipes or hoses. Thus they provide exactly the same capability as a hydraulic gearbox, but with the advantage of remote mounting of the drive. The linking pipes can be flexible or even disconnected to remove a complete unit. Hydraulic drives are particularly useful for high torque, low speed drives into congested, dirty areas, or where mechanical drive alignment is impossible. See **Section 2.6.2** for a practical application. The drive can be a fixed displacement (fixed ratio except for slip) or variable displacement system, with variable displacement being preferred for starting. The hydraulic pressures can be over 100 bar, and will require robust pipework and appropriate relief systems. Pipework should be protected from mechanical damage. The hydraulic oil used will be of high quality, the hydraulic motor unit will normally be part of a package unit including oil tank, filter, cooler and relief system.

Figure 5 – 8 Small Hydraulic Power Pack & Hydraulic Slewing Drive Motor with Integral Brake

The hydraulic unit is normally driven by an electric motor but there is nothing to prevent it being driven by a diesel engine or the power take-off from a gas turbine.

Hydraulic drives can often run forwards and backwards, in which case good design is to run two main supply / return hydraulic lines with a smaller bore balance line. The balance line handles leakage flow and keeps the hydraulic motor shaft seal at the correct pressure to minimise outwards leakage while preventing ingress of dirt and water. Hence, correctly set up, the hydraulic motor can operate in dirty locations or underwater.

The very high oil pressures used in hydraulic systems give rise to the risk of injury from fluid jets, if pipework is damaged. Jets of oil can also reach sources of ignition at some distance from the release point. The jet can be well atomised thus easily ignited. The relief systems are vital otherwise the generated pressure under fault conditions can easily rupture pipework.

5.5.4 Hydraulic Couplings

Hydraulic couplings are self-contained units comprising co-axial input and output shafts, carrying rotors filled with oil. There are 3 typical variants :-

In simple hydraulic couplings, the input shaft drives a doughnut-shaped rotor containing a fixed charge of oil. As the rotor spins, internal vanes cause the oil charge to rotate. A second set of vanes, inside the hollow rotor, is connected to the output shaft. Hence the rotating oil charge causes the output shaft to rotate. The output and input torques are the same, but the output speed reduces as torque increases. The output speed is always less than the input speed. These units are ideal for starting conveyors and hoists, which have very high starting torques. They are inefficient and cannot be controlled. If the driven equipment does not start or runs slowly, the internal oil charge becomes hot. If the drive motor is not shut down automatically, a thermal fusible plug will blow and discharge the oil charge into the drive guard.

This level of hazard probably rules out simple hydraulic couplings for offshore installations.

Variable charge hydraulic couplings work on the same principle, but are housed in a transmission casing which contains an oil tank and a control system. The oil charge in the coupling is now variable, and is constantly recycled through a cooler. The control system can now increase the oil charge to increase output speed, and reduce it when required. If the drive stalls or the oil overheats, the charge can be reduced to a minimum value, and if necessary the drive motor will be tripped. Even if the coupling fails, the transmission casing will contain the oil charge. A typical duty is to drive large reciprocating pumps, which are controlled on the basis of variable speed.

Variable charge hydraulic couplings pose similar hazards to hydraulic gearboxes, and can safely be used where appropriate. The choice of drive will depend on the demands of the application, and on personal preference.

Torque converters are a form of variable charge hydraulic coupling with one special feature – they are able to deliver a higher torque on the output shaft than is applied to the input shaft, or they can drive the output shaft at a higher speed than the input shaft. The penalty for this flexibility is higher internal complexity, and generally poorer efficiency. Conventional automotive automatic transmissions use torque converters, some have special features to improve efficiency.

The hazards are the same as for variable speed hydraulic couplings, with the additional potential for overspeed of the driven device at low torques.

For modern electric motor drive applications, inverters are now often used instead of hydraulic couplings.

5.6 SHAFT COUPLINGS

Shaft couplings are designed to transmit the torque between two co-axial shafts with minimal loss of power. Any miss-alignment between the shafts gives increased bearing loads so it is best practice to minimise the miss-alignment at the normal running condition. This often requires the alignment to be pre-set in anticipation of thermal expansion.

Most large machine shaft couplings comprise a pair of hubs mounted on the input and output shafts respectively, a pair of flexible elements mounted to the hubs, and a spacer unit connecting the flexible elements.

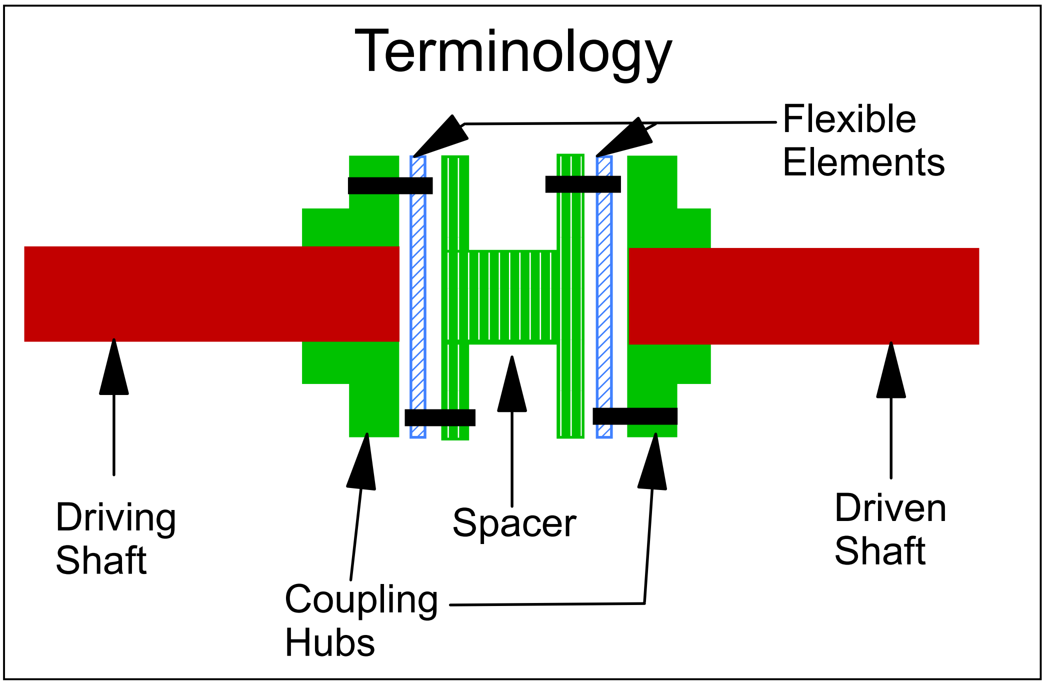


Figure 5 – 9 Shaft Couplings

This configuration gives the ability to accept parallel and angular shaft misalignment. The flexible elements may be formed by spherically cut gears, flexible metal plates or membranes, or rubber blocks.

Traditionally, gear couplings were used for high power drives. These have a long service life and high torque / power capability, but require lubrication. Grease lubrication is simple but periodic re-greasing is required. If this is neglected, the coupling can lock up and fly. Oil lubrication can be used instead, a continuous feed of oil is taken form the adjacent machine, injected into each gear mesh. The used oil is ejected from the spinning hub. Hence an oil-tight coupling guard is required to collect the oil. Oil filtration quality is vital as the gear teeth act as a centrifuge, removing any solids that can then jam the teeth.

More modern high power couplings use pressed metal membranes. These are contoured discs, which can flex enough to permit small movements. They are not tolerant of large misalignments, but these are unacceptable on large drives anyway. Provided there is no corrosion, and the alignment is within limits, these couplings do not require maintenance.

Large medium – high power couplings are available which use rubber blocks as the flexible element. These have the advantage of providing torsional damping, which is beneficial for

screw compressors and high ratio gearboxes. The couplings are physically large, and require periodic inspection to replace worn rubber blocks.

Low power couplings use moulded rubber discs, rosettes or tyres. These are often sufficiently flexible that a single flexible element will suffice and no spacer will be required. These couplings require no maintenance.

All couplings can be prone to being thrown if badly fitted or misaligned, or if the supporting shaft fails.

5.6.1 Lateral & Torsional Critical Speeds

All machines and rotating equipment have “Critical Speeds” at which natural frequencies of the system coincide with running conditions. When this occurs, the small vibrations caused by unbalance or misalignment build on each other, causing ever-increasing oscillations. Extended running at a critical speed can cause machine destruction, unless the system is very heavily damped. Steel shaft systems generally have very little damping and problems are normally avoided by ensuring that machines run at speeds well removed from critical. Many machines run at between the first (lowest) critical speed and the second (next to lowest) critical speed. In this case it is good practice to ensure that the shaft passes through the critical speed as quickly as possible.

Lateral critical speeds refer to transverse vibrations of the shaft and bearings. They can, in general, be predicted quite accurately by the vendor, using sophisticated computer programs. Typical values for a centrifugal compressor might be First Critical at 4500 rev/min and Second Critical at 8300 rev/min. In this case fixed speed operation at 7200 rev/min would be satisfactory. Critical speeds are affected by the density of the process fluid handled, and can change in service e.g. due to bearing wear. It is good practice to avoid running within 15 % of a critical speed, as the vibration increase occurs over a band on either side. Engineering changes, e.g. fitting a heavier coupling, can significantly move the critical speed.

It is normal practice to test, carefully, for critical speeds during commissioning, to validate the vendor predictions and confirm safe operating margins.

High speed rotating equipment with light weight rotors, e.g. centrifugal compressors and gas turbines, are particularly sensitive to lateral critical speed problems. High speed rotor balancing to appropriate standards, and meticulous fitting practice, especially of bearings and labyrinths seals, will minimise the risk of problems.

Torsional critical speeds refer to torsional oscillations of the complete shaft system. Again, computer analyses can be done, the complete rotating system including any ancillary drives must be covered. Gas turbines and centrifugal pumps and compressors impose little torsional oscillation and are benign. Reciprocating compressors and diesel engines can impose huge low frequency torsional oscillations, and gearboxes and synchronous, stepper and slave motors can input high frequency oscillations. Low frequencies can be damped with the aid of a flywheel, high frequencies by the use of an appropriate rubber element coupling. The fundamental design of the equipment defines the problem – a single cylinder 4 stroke engine would probably be the worst case.

In either the case of Lateral or Torsional critical speeds, a problem developing in service usually points to a change in the equipment. Possible causes include :-

- Radial bearing, shaft sleeve or labyrinth seal worn or rubbing.
- Shaft unbalance through bending, fouling, blade failure.
- Operating multi-cylinder reciprocating machines with parts of the motion works or valves damaged or removed
- Inappropriate modifications particularly to shaft couplings.

5.7 PIPING SYSTEMS

All piping systems should be designed, fabricated and tested to standards appropriate to the duty and environment. The standards will cover materials, thickness, fabrication, inspection and testing, operating pressure and temperature envelope, appropriate connection methods and gasket materials.

There are two distinct dimensional standards for piping systems in use in Europe, the DIN / ISO system (based on Continental European practice) and the ANSI system (based on American practice). UK Oil, Gas & Petrochemicals operations tend to use the ANSI system, with possible vendor preference for DIN/ ISO pipework and fittings, particularly for service pipework. Bolts, joints and fittings for the two systems should not be mixed as they are not compatible but are difficult to tell apart by inspection. It is important that packages are specified to use appropriate standards, preferably using consistent standards for all piping in one package. It is important that interfaces between different standards are clearly identified.

Where necessary, connecting between the two systems is best done with special adapters or welded connections. Pipe flanges are stamped on the edge with their type and size. Small bore compression fittings, in particular, will fail if made up with mixed parts or used with the wrong pipe size.

The majority of the pipework on an Oil & Gas installation will be of carbon or stainless steel, these pipes are strong enough for conventional pipe fabrication and supporting practices to be used. For hydrocarbon lines, all-welded construction is required, with flanges restricted to the minimum necessary valve and equipment flanges. Even here, welded connections can be used on particularly critical service. Flanges should always be located where they can be made properly and can be inspected. For low-hazard fluid e.g. water, flanged pipework can be used, although it is still cheaper and more convenient to weld long runs where access is not required.

Steel pipework can deteriorate internally or externally, typical mechanisms being corrosion and stress-corrosion cracking. Corrosion under lagging is particularly insidious, and can cause pipe supports to fail at the same time. All pipework should be subject to a controlled inspection regime, with the frequency and degree of inspection selected based on experience and potential consequences of failure.

See **Section 5.1.1** for comments on the special double wall pipework used in critical parts of Gas Turbine fuel systems.

Other metals, e.g. copper, may be used, also a range of plastics and glass reinforced plastics for some vents and ducts. These systems are not generally subject to corrosion but are mechanically weak, requiring better supporting and mechanical protection than steel pipework. Un-reinforced plastic pipes are particularly prone to damage from impact or temperatures typically in excess of 70 – 80 C. Where such pipes are appropriate, they should be supported and protected e.g. by being run on cable tray. Even small bore steel pipes, e.g. for instruments, should be supported and protected in such a manner. Within congested skids, small bore pipes are particularly vulnerable to damage, it should be part of the design and inspection brief to ensure that this pipework is routed and supported sensibly.

Screwed connections of any size are prone to leakage and vulnerable to damage. Tapered screw threads are particularly weak and should be avoided. Pipes of above 1/2" / 15 mm should certainly be flanged or welded. For smaller pipes, parallel threaded connections can be used to equipment ("O" ring or gasket sealed), with appropriate grade compression fittings for pipework. Seal welding of screw fittings may be practical. The fitting of flanges to small screwed pipes simply risks the pipe thread snapping off. For example, API 610 (Eighth Edition) standard Clause 2.3.3.4 prohibits the use of screwed pressure connections to pump casings on flammable or hazardous liquids. Note that screwed blanking plugs are permitted (Clause 2.3.3.7). Where screw threads are subject to corrosion, this poses the risk of plug blow-out and the consequent hazard of a process fluid release. Hence it is essential that such screwed plugs

be subject to maintenance inspection. For effective inspection, the plug must be removed and the plug and socket threads inspected. External inspection only does not assure security.

In order to permit thermal expansion of hot pipework, it is normal to design in expansion bends and loops. Such pipework often requires special supports, and must be allowed room to expand. The inspection procedures for such pipework must include checks that supports have not seized or corroded, and checks that expansion gaps have not been compromised.

The use of bellows to permit expansion of hydrocarbon lines is very unsatisfactory practice and must be avoided if at all possible. Any such bellows must be easily accessible and subject to frequent inspection. Bellows are prone to fatigue failure and are easily damaged by pressure pulsations or mechanical impacts.

For machine packages prone to pulsations, e.g. reciprocating compressors or pumps, it is necessary to assess the pipework and mechanical system for resonances. API 618, for example, gives guidance on pulsation and vibration control for Reciprocating Compressors. It calls for the purchaser to specify one of 3 progressively more sophisticated design approaches.

Where machines and rotating equipment are located on anti-vibration mountings, it is reasonable to use bellows or suitable flexible pipes for non-hazardous services. The items should be robustly made with permanent end connections to standard pipe flanges. This permits a damaged or suspect flexible to be changed easily. Such bellows and flexibles should be registered and service life monitored.

Bellows are fully welded items so should have no fugitive leakage problems, they are often fitted with tie bars to limit travel and thus prevent damage to the convolutions. Flexible hoses are typically made using fibre reinforced elastomers, often with a stainless steel wire braid outer sleeve. Some designs can be made up on site using clamped or screwed terminations to steel stub pipes. Any machine connections, as above, should use permanent terminations which are retained by a crimped or swaged steel sleeve. These are made up by specialist hydraulics service companies who can produce consistently good and tested assemblies. Flexible hoses should be treated with care as they can be permanently damaged by crushing, kinking or stretching.

The primary hazard from the failure of a pipe is the release of the contained fluid and thus its fire/ explosion / toxicity hazard. The secondary hazard is the loss of the duty which the fluid served. Thus a cooling water line failure poses little direct hazard, but the associated equipment could overheat.

5.8 INGESTION PREVENTION

Liquid ingestion into gas compressors can lead to significant machine damage and hazard from loss of containment due to the damage caused. Ingestion is a particular problem for reciprocating compressors, but will also affect all other types compressor including lubricated screw compressors. Lubricated screw compressors, though designed to handle substantial quantities of liquid, can be overloaded leading to machine damage. This is particularly the case if the liquid is in discrete slugs.

The possible sources of liquid ingestion are in summary :-

- Inlet to the compressor :-
  - Leak of coolant into the gas line – from coolers, or jacketed pipes.
  - Liquid trapped in inlet pipe above machine inlet.
  - From upstream process equipment scrubber or catchpot overflow, condensation.
- Machine Sources :-
  - Inward leak of coolant.
  - Inward seal system leakage and accumulation.
  - Condensation.
  - Reciprocating Compressor : -
    - Cylinder lubricant build up during period of machine offline.
    - Cracked cylinder liner.
    - Failed gasket.
  - Lubricated screw compressors : -
    - Overload of liquid.
    - Machine not drained following shutdown.

Protection available : -

- Inlet : -
  - Adequately sized knock-out pots or effective separators to separate liquid and retain it until removal.
  - Cyclone and/or low velocity separation.
  - Drainage by automatic trap or level control.
  - Gauge glass / level indicator, high level alarm and trip on inlet condensate removal vessel / separator / catch-pot.
  - Drains on pulsation dampers.
  - Moisture removal device at inlet.
  - Drain points.
- Avoidance of Liquid accumulation : -
  - Piping falling to drain points with no hold up.
  - Automatic isolation valves to barrier migrating vapour from inlet, to supplement NRV to prevent back flow of vapour.
  - Manual bypass around condensate removal level control valve or trap.
  - Heating to avoid condensation.
- Machine (reciprocating compressor) : -
  - Top inlet bottom exit horizontal cylinder.
  - Cylinders maintained above condensation temperature.
  - Spring relief of cylinder head.
  - Small capacity, limited rate cylinder lubrication interlocked on machine stopping.

Pressure testing of cooling circuits, design to avoid direct leak paths to cylinder.

Ancillary equipment : -

High integrity heat exchangers.
Separator for continuous liquid removal.
Inert gas purging of condensing gas.
Control of liquid inventories to avoid over-filling.

Operations and maintenance : -

To minimise the possibility of liquid ingestion, either during start up or under normal operation operating procedures and instructions should include the following aspects : -

Checks on installed systems : -

Suction separation vessels and knock out pots.
High level switches and indicators.
Tell tale drain points.
Vibration monitoring systems.
Operating records for evidence of liquid condensation carry over, leakage into or from cooling systems

Possible pre start checks : -

(different procedures may exist for immediate re-start or re-start after extended shut down)

Check on the operation of each separator drain valve, consider the possibility of chokes.
Check for liquid in the compressor inlet line down stream of separator or knock out pot.
Check cooling system is not causing condensation inside machine.
Check for liquid by opening drains on interstage pipes and coolers.
Open drains on each suction and discharge pulsation damper.
Check for inward leaks of cooling medium into machine.
Check for inward leak of seal barrier fluid into machine.
Check condition of trace heating when fitted.
Where possible and particularly for reciprocating machines turn machine over slowly (bar over) and check for mechanical noise and resistance to motion.

Checks during machine operation : -

Check operation of each knock out pot / separator drain valve and that flow is not excessive.
Checks on machine efficiency.
Checks on cooling systems – loss of coolant or contamination of coolant system.
Routine inspections defined for all trips alarms, and operation of emergency shut off valves.

Liquid ingestion is a rare occurrence so checks are expected to yield zero return for most of the time – this doesn't mean they should not be done.

Codes and Specifications.

API codes for the specific machine cover general requirements for ingestion avoidance and protection (see **Section 5.15**)

5.9 BEARINGS

Bearings are at the heart of all machines and rotating equipment. Their purpose is to support and guide moving parts within the equipment. The most sophisticated bearings are those which support high speed heavily loaded rotating shafts. Two distinct designs are used,
Plain Bearings and Rolling Element Bearings.

Plain bearings rely on a lubricating oil film between two sliding surfaces. Once the oil film has been established, the bearing should run essentially for ever without significant wear. Plain bearings are also capable of carrying high shaft loads. They are reliant on a lubricant support system to establish and maintain the oil film; this commonly requires a pressurised supply of cooled and filtered oil. Plain bearings are relatively massive and bulky, particularly the "tilting pad" designs used in modern high performance process equipment. The long operating lives of plain bearings make them preferred in many applications.

Rolling Element bearings utilise balls or rollers to separate the moving surfaces, this mode of operation generates much less heat than plain bearings, thus absorbs less power and requires much less lubricating oil. High-speed rolling element bearing assemblies are smaller / lighter than plain bearing systems, hence they are used in the aero-derivative gas turbines normally used offshore. Rolling element bearings are subject to fatigue mechanisms thus have a fairly predictable wear-out progress, which can be followed by condition monitoring equipment. Process overloads or lubrication failures, however short, can cause damage equivalent to thousands of hours of normal service.

Bearing wear does not in itself pose a safety hazard, but if a bearing actually fails or seizes, the heat generated can locally melt the shaft. The resulting bent or broken shaft can tear seals from housings or permit a coupling to be thrown. The close internal clearances in e.g. a barrel compressor, combined with the massive casing, will limit the external effect of a bearing failure. Periodic condition monitoring will not, in general, provide data quickly enough to prevent a bearing failure, it is necessary to have continuous detection / monitoring of key parameters e.g. bearing temperature, oil pressure.

Worn bearings can result in excessive vibration or shaft movement; this can cause further damage to e.g. labyrinth seals, increasing vent rates or shaft loadings. Increasing vibration increases the risk of failure of instruments and similar components.

5.10 AIR INTAKE FILTER SYSTEMS

Air intake filters remove dirt and debris from the air supplies to Gas Turbines, Fans, Air Compressors. In the case of the Gas Turbine the primary purpose is to prevent fouling of the compressor itself. To achieve the necessary filtration, it is common to use two filter stage stages in series. The first will be a thin (25 – 50 mm) coated glass fibre mat, fitted either as cassettes or as a continuous felt roll, normally in a vertical holder. The second stage will be box-like "HEPA" (High Efficiency Particulate Air”) filters, typically 300 mm cube sized for easy handling, or bag filters of coated textiles. Filters are mounted in a box-like "house", for which stainless steel construction is preferred to prevent corrosion and avoid paint deterioration. Downstream of the filters will be a mechanical screen that should be able to retain a broken filter cassette.

Differential pressure gauges, with alarms, should be fitted across each filter bank, to monitor fouling rate and guide filter change intervals. Compressor efficiency will gradually deteriorate as the filter blocks; changing the filter should restore the efficiency. A gas turbine or air compressor can suck in a blocked filter or even collapse the filter house, so it is good practice to fit a "blow-in door" to act as a safety valve. This door must be linked to a turbine trip sequence.

Filters can be blinded by snow and, in particular, by freezing fog. It is therefore good practice to fit an upstream louver system (which removes rain / spray). Considerable benefit can be gained by siting the intake duct to reduce any such ingestion risk. .

5.11 COOLING SYSTEMS

Process equipment is typically cooled against air or water.

Air cooling is very simple but requires relatively large, fragile finned tube type heat exchangers. It is not possible to cool below perhaps 10 C above local ambient.

The potential hazards of air cooling relate to release of the medium being cooled, should a tube fail, and the risk of the failure of the associated fan.

Water cooling uses compact and robust heat exchangers, for offshore installations it would be very desirable to use a fresh water intermediate cooling circuit, which is then cooled by seawater. It should then be possible to cool to about 8 C above sea temperature. The intermediate circuit protects equipment heat exchangers against salt scaling or corrosion, and minimises the potential for pollution. Water based cooling systems present few risks.

Should loss of cooling itself pose a safety hazard, then redundancy or duplication of cooling systems (and their power supplies) may be required.

5.12 CONDITION MONITORING

Condition monitoring can provide very valuable information about the status and safety of rotating equipment while it is running. The only hazards associated with carrying out condition monitoring activities might relate to the manual taking of oil samples, and attempting to maintain shaft sensors on running plant. Lack of condition monitoring should not contribute to safety hazards, as condition monitoring should not be a substitute for protective safety systems, though effective monitoring will reduce the demand rate on the protective device.

Inspection & overhaul activity timing may be based on the assumption of appropriate condition monitoring being in place. If this is not the case, these intervals should be reduced.

Equally, there is a good case for extending maintenance intervals based on effective condition monitoring, provided that favourable results are achieved, as in good oil sample test results.

The chart below shows in outline the typical monitoring carried out on machinery

Machine Monitoring	Gas Turbine	Centrifugal Compressor	Recip Compressor	Pumps	Motors	Diesel Engines
Speed	Y	Y	Y	Y		Y
Vibration levels	Y	Y	Y	Y	Y	Y
Bearing temps	Y	Y	Y	Y	Y	Y
Seal system flow / pressure		Y	Y	Y		
Lube oil flow / pressure	Y	Y	Y	Y	Y	Y
Oil supply level	Y	Y	Y	Y	Y	Y
Cooling water flow / temp		Y	Y			Y
Oil filter condition	Y	Y	Y			Y

Condition monitoring to enhance safety is the subject of a HSE Contract Research Report CRR120 providing details of the techniques and areas for application of the techniques. Below is a chart showing typical application of techniques:

5.12.1 Condition Monitoring Techniques for Machinery and Rotating Equipment

This listing of techniques is by no means exhaustive, a comprehensive listing of techniques and detailed discussion on these is given in Appendix 4 of the HSE Contract Research Report CRR120.

Problem Area	Techniques Available
General machine Systems	
Seal / Gland Leaks	Thermal Inspection Techniques
	Acoustic Emission
	Ultra sound Techniques
	Seal Leak off monitoring
	Shaft Seal Monitoring
	Filtration
Hot/ Noisy bearings	Vibration techniques
	Lubricant Analysis
	Thermal Inspection Techniques
	Look listen feel
	Ultra sound
Excessive /Abnormal Vibration	Performance Analysis - determine operating point
	Vibration Techniques - Phase/ spectrum analysis

Pumps

Repeated Pump Trips	Performance Analysis - direction of rotation
Mechanical Failure	Alignment
	Performance Analysis - cavitation
	Vibration Techniques - Phase/ spectrum analysis

Motors

Mechanical Failure	Alignment
	Rotor bars - current analysis
	Vibration Techniques - Phase/ spectrum analysis
Insulation breakdown	Thermography

Compressor / Gas Turbines / Fans

Hot/ Noisy bearings	Vibration techniques shaft / housing
	Lubricant Analysis
	Thermal Inspection Techniques
	Oil temperature / pressure
	Shaft position monitoring

- Surge / Stall
  - Noise Monitoring
  - Pulsation monitoring
  - Performance analysis
  - Current monitoring
  - Shaft Seal Monitoring

Reciprocating Compressors

- Valve Failure
  - Thermal Inspection
  - Performance monoitoring
  - Listen
  - Acoustic emission

- Seal / Gland Leaks
  - Thermal Inspection Techniques
  - Acoustic Emission
  - Rod drop monitoring
  - Seal Leak off monitoring
  - Shaft Seal Monitoring

5.12.2 Comments Against Selected Condition Monitoring Techniques

(For further details see the CRR 120 as previous)

Techniques Available	Comments
Vibration Measurement	Fundamental indicator of machine condition – indicative of dynamic stresses applied. Trending of results will determine rate of deterioration. Clear statement of allowable limits required. Measurement of housing velocity / acceleration or detection of rotating shaft position can be provided by equipment from a wide range of suppliers. Output can be displayed directly or analysed for problem understanding. Protective systems can be based on logical assessment of data, ultimate protection should be provided by independent device with direct measurement of vibration. e.g. accelerometer set to pick up major machine disruption.
Shaft position measurement	Measurement of shaft axial position will provide indication of major thrust bearing damage. Use as ultimate protection on failure of bearing temperature probes. Reliability of device improved by design in redundancy for example 2 out of 3 readings from independent devices required to provide protection avoiding spurious trips.
Bearing temperature	Indication of deterioration within the bearing. Very dependant on position of temperature probe with respect to point of heat generation. Trending of information will identify deterioration of system. High temperature gives indication of fault condition (though the fault may be within the probe). Measurement of temperature may not identify fault conditions.
Oil Temperature / Pressure	Service systems monitored, lack of lubricant pressure will lead to rapid deterioration of the bearing.
Oil Condition	Oil analysis will provide history of damage to bearing systems, and potential for future deterioration. Oil contaminants such as water will affect bearing performance, whereas traces of metal can show wear processes occurring. Provides information to reduce demand rate on protection devices.
Seal Leak off monitoring / flow monitoring	Simple measurements, providing both operational monitoring and machine protection when values exceed design limits.
Performance Analysis	Monitoring of process parameters (pressure ratio / temperature / flow / power) will provide indication of operational instability. Extended operation of the machine in unstable conditions can result in major machine damage. Protection of the machine provided to avoid internal damage. Deteriorating performance from the machine may give indication of machine fouling / corrosion. Protection of the machine is required by direct measurement.

5.13 CONTROL SYSTEMS

Machines within a package must be integrated to function as a complete system. Therefore control systems are designed to provide this essential control and protection for the machine elements. There will be key logical interlocks between the main control system and the machine or package control. These will provide for start / run permits and sequence control, e.g. Control Room authorisation for machine start. These logical signals must be of high integrity as they cannot be bypassed or ignored. There will then be numerical (possibly a mixture of analogue and digital) signals controlling e.g. compressor load, set speed (if variable), and for data logging.

It may be permissible to operate with manual over-ride on some of these signals, for example during load changes. Alternately, the system may be intended to operate purely in fully automatic mode. This will require increased sophistication e.g. speed ramping, critical speed avoidance, operating temperature bands, load and speed matching during duty changes.

Fixed speed electric motor drives should avoid the issues related to operation close to or on critical speed, the installation should be designed to run well away from critical speeds, and the run-up and run-down should pass through any critical speeds quickly enough to avoid problems. The rapid run-up, in particular, can on occasion cause damage to axial or centrifugal compressor seals, due to high vibration levels and local heating. Variable speed or soft start systems can avoid the seal problems by gentle acceleration at low speeds, but care is required to ensure that critical speeds are passed through briskly. Normally, the operating speed range should not include any critical speeds, but if there are known critical or resonant conditions then either procedures or software should be set up to prevent operation at these conditions.

Although as much as possible of the Package will be tested onshore, prior to shipping, it will not be possible to fully test and tune the control system prior to commissioning. The interlocks, and to some degree the load control, might be tested by use of a computer model. The greater the degree of automation, the greater the demands on the commissioning team, who must set up and prove the system, knowing that in normal operation load changes will be done without close manual supervision.

Control valves within a package will be specified and configured to suit the particular requirements of the duty, for example temperature control valves are normally slow acting and pressure or flow control valves often have to be fast acting. Anti-surge or blow-off valves often have a dual requirement to operate slowly and accurately in the normal control mode, but to drive rapidly to a part or full open position in response to a demand from the surge control system. Every component in such a system must be compatible with this requirement. For example, anti-surge control valves often have much larger actuators than might be expected for their size. It may be necessary to mount a large and a small valve in parallel to achieve control over a range of operating conditions. It is not generally realistic to expect a tight shut-off from a control valve, thus fire-safe isolation valves are normally separate from the control system and have a simple open/ closed action.

DCS (Distributed Control Systems) have to be specified and set up carefully if they are used in machine control applications. DCS systems do not monitor and control continuously, instead they sample available data at pre-set intervals. Some control actions and indications can work with intervals of several seconds between samples, but machine control requires many samples per second. This is one of the reasons to prefer machine-specific control systems, with monitoring and supervision from the DCS.

Control software must be rigorously checked, subject to strict version and change recording and control. Pre-programmed cards can be fitted to the wrong machine; they may be physically identical (to Model and Serial Number) but carry different instructions.

Details of the requirements for these systems are noted in the Guidance notes for each element.

5.14 INSTALLATION

All machine elements are mounted to a common baseframe that is sufficiently rigid to maintain machine alignment, despite movement of the supporting structure or vessel. The 3-point mounting system eliminates the transmission of twisting forces to / from the baseframe. In order to save space, and the weight of additional bases, as many as possible of the ancillary systems e.g. lubrication oil system, seal gas support system, are built into the main baseframe. The control panel may be built on to the end of the baseframe (which is convenient for pre-wiring) or mounted separately (which permits control panels to be grouped together).

The available space on the package will be tightly packed, making access to internal components quite difficult. Thus any problem on one component has the potential to affect adjacent components / systems, whether by release of material, vibration or over-heating. Similarly, it may be necessary to remove a component either to work on that component or to gain access to adjacent components. For pump installations it is important that there is sufficient access to remove the shaft or cartridge (which can be very long) in the appropriate direction. Special tools, e.g. slide frames, may be required. Similarly large electric motors are serviced by removing the rotor axially, using special lifting equipment.

The package will require effective ventilation to ensure dilution of any leakage gas.

Packages with a mix of foot-mounted and centre-line mounted drives, particularly if they include a gearbox, are difficult to align. The manufacturer should provide alignment instructions but it is valuable to understand how the various thermal expansions have been allowed for. “Hot” alignment is a valuable check but can be difficult and frustrating in practice as the equipment is moving while being measured. It may be possible to fix sensors to machines and monitor the alignment during a working run. Machine vibration readings give a good guide to alignment quality and can be analysed to look for the cause of a problem.

Mechanical Hazards
Hot surfaces will be fitted with heat shields or thermal insulation. These must be in place for operator safety.

Access Hazards
The design of packaged equipment should take account of all normal operational and maintenance activities with suitable access to all maintainable parts. The congested nature of the design may leave potential tripping hazards, and other obstructions. These are items of concern for operator movement, as well as the consequence of inadvertent damage to small bore pipelines and instrument connections which could lead to machine damage if they become disrupted.

5.15 APPLICABLE STANDARDS

Selection of British Standards Relevant to Machinery in use in Petrochemicals Installations (Transposed Harmonised Standards)

BS EN 292-1 1991	Safety of Machinery – Basic concepts and general principles for design – Part 1: Basic terminology and methodology.
BS EN 292-2 1991 & BS EN 292-2/A1 1995	Safety of Machinery – Basic concepts and general principles for design – Part 2: Technical principles and specifications.
BS EN 418 1992	Safety of Machinery – Emergency stop equipment, functional aspects – Principles for design.
BS EN 457 1992	Safety of machinery – Auditory danger signals – General requirements, Design and testing. (ISO 7731: 1986 modified)
BS EN 547-1 1996	Safety of Machinery – Human body measurements – Part 1: Principles for determining the dimensions required for openings for the whole body access into machinery. (Also Parts 2 & 3)
BS EN 563 1994 & BS EN 563/A1 1999	Safety of Machinery – Temperatures of touchable surfaces – Ergonomics data to establish temperature limit values for hot surfaces.
BS EN 626-1 1994	Safety of machinery – Reduction of risks to health from hazardous substances emitted by machinery – Part 1: Principles and specifications for machinery manufacturers.
BS EN 626-2 1996	Safety of machinery – Reduction of risks to health from hazardous substances emitted by machinery – Part 2: Methodology leading to verification procedures.
BS EN 746-1 1997 & BS EN 746-2 1997 & BS EN 746-3 1997	Industrial thermoprocessing equipment – Part 1 : Common safety requirements Part 2: Safety requirements for combustion and fuel-handling systems. Part 3: Safety requirements for the generation and use of atmosphere gases.
BS EN 809 1998	Pumps and pump units for liquids – Common safety requirements.
BS EN 842 1996	Safety of machinery – Visual danger signals – General requirements, design and testing.
BS EN 953 1997	Safety of machinery – Guards – General requirements for the design and construction of fixed and movable guards.
BS EN 954-1 1996	Safety of machinery – Safety-related parts of control systems – Part 1: General principles for design.
BS EN 981 1996	Safety of machinery – System of auditory and visual danger and information signals
BS EN 982 1996	Safety of machinery – Safety requirements for fluid power systems and their components – Hydraulics.
BS EN 983 1996	Safety of machinery – Safety requirements for fluid power systems and their components – Pneumatics.
BS EN 1012-1 1996	Compressors and vacuum pumps – Safety requirements – Part 1: Compressors.
BS EN 1037 1995	Safety of machinery – Prevention of unexpected start-up.
BS EN 1050 1996	Safety of machinery – Principles for risk assessment
BS EN 1088 1995	Safety of machinery – Interlocking devices associated with guards – Principles for design and selection.
BS EN 1127-1 1997	Explosive atmospheres – Explosion prevention and protection – Part 1: Basic concepts and methodology.
BS EN 1299 1997	Mechanical vibration and shock – Vibration isolation of machines – Information for the application of source isolation.
BS EN 1837 1999	Safety of Machinery – Integral lighting of machines.
BS EN ISO 4871 1997	Acoustics – Declaration and verification of noise emission values of machinery and equipment. (ISO 4871:1996)

BS EN 60204-1 1992 & 1997	Safety of machinery – Electrical equipment of machines – Part 1 : General requirements (IEC 60204-1 : 1997)
BS ISO 3977-5 2002	Procurement of Gas Turbines for Oil & Gas Industries.

Selection of API Standards Relevant to Machinery in use in Refineries / Offshore

API 1111 1999	Design, Construction, Operation & Maintenance of Offshore Hydrocarbon Pipelines
API 11P 1989	Packaged High Speed Separable Engine-Driven Reciprocating Gas Compressors
API 11PGT 1992	Packaged Combustion Gas Turbines
API 14E 1991	Design & Installation of Offshore Production Platform Piping Systems
API 14F 1999	Design & Installation of Electrical Systems for Offshore Production Platforms
API 14G 1993	Fire Prevention & Control on Open Type Offshore Production Platforms
API 14J 1993	Design & Hazards Analysis for Offshore Production Facilities
API 1B 1995	Oil Field V-belting
API 2031 1991	Combustible-Gas Detector Systems & Environmental / Operational Factors Influencing their Performance
API 541 1995	Form-Wound Squirrel Cage Induction Motors – 250 HP and larger
API 546 1997	Form-Wound Brushless Synchronous Motors – 500 HP and larger
API 55 1995	Conducting Oil & Gas Producing & Gas Processing Plant Operations involving Hydrogen Sulphide
API 610 1995	Centrifugal Pumps for Petroleum, Heavy Duty Chemical and Gas Industry Service
API 613 1995	Special Purpose Gear Units for Petroleum, Chemical and Gas Industry Services
API 614 1999	Lubrication, Shaft-Sealing & Control Oil Systems and Auxiliaries for Petroleum, Chemical & Gas Industry Services.
API 616 1998	Gas Turbines for Refinery Services
API 617 1995	Centrifugal Compressors for Petroleum, Chemical & Gas Industry Services.
API 618 1995	Reciprocating Compressors for Petroleum, Chemical & Gas Industry Services.
API 619 1997	Rotary-Type Positive Displacement Compressors for General Refinery Services
API 660 1993	Shell and Tube Heat Exchangers for General Refinery Services
API 661 1997	Air- Cooled Heat Exchangers for General Refinery Services
API 670 1993	Vibration, Axial-Position & Bearing-Temperature Monitoring Systems
API 671 1998	Special-Purpose Couplings for Refinery Service
API 672 1996	Packaged, Integrally Geared Air Compressors for Petroleum, Chemical & Gas Industry Services
API 674 1995	Positive Displacement Pumps – Reciprocating
API 675 1994	Positive Displacement Pumps – Controlled Volume
API 676 1994	Positive Displacement Pumps – Rotary
API 677 1997	General- Purpose Gear Units for Refinery Service
API 682 1994	Shaft Sealing Systems for Centrifugal and Rotary Pumps
API 686 1996	Machinery Installation & Installation Design

SECTION 6 OPERATION SUPPORT GUIDANCE

INSPECTION GUIDANCE NOTES – OPERATION SUPPORT GUIDANCE.

CONTENTS

6.1 GENERAL

- ***This section of the guide covers the effects of operation on machinery behaviour, but does not cover how the operator actions would be carried out.***

- ***Mal-operation of machines is a common cause of their failure, which may lead not only to loss of plant production and damage to equipment, but also to hazardous incidents. Operation of rotating equipment for all applications cannot be considered in isolation and must be viewed as a system, depending on system conditions and operational demands.***

- ***Machinery and Rotating Equipment are designed with intrinsic limitations and protective systems to keep the machine operating within a safe and acceptable window of operation. Major machine systems, such as gas compressors driven by gas turbines, will normally have extensive monitoring and protective systems. Incidents with such systems can develop very rapidly, leading to situations where intervention by operators, prior to requirement for taking protective action, is impracticable due to the short time scale available.***

- ***Correct operating procedures and operator actions are relevant to the safe control and operation of the machine system. Detailed below are operator actions and interventions which can in normal circumstances assist in avoiding incidents, limiting the effect of an incident, and reducing the demand rate on the protective systems.***

- ***It is assumed that the operations have been assessed for risk and are exercised within a safe system of working, with associated training of personnel, and operators are equipped with the relevant personal protective equipment.***

6.2 IMPACT OF OPERATIONS

- ***The operator provides a key and very powerful control on the satisfactory operation of any machine system. Identification of deteriorating trends in machine performance, or non-conformances with the installation when carried out in a systematic way will reduce demands on protective systems, potentially at the point prior to the onset of damage.***

- ***The dilemma for operators is always at what point to intervene prior to protective systems engaging (causing processing interruptions), and damage occurring. Operating demands will also pose questions on the "acceptable" level of fault or degradation of the system that can be tolerated.***

- ***Intervention of operators to override protective devices or sequences must only be done under the strictest of controls with regard to consequences for the machine or system that they have been designed to protect.***

- ***The amount of energy stored in a machine system can be very high, even with appropriate protective systems, dissipation of energy from the machine can take a significant amount of time (an uncoupled electric motor may take over 45 mins to coast to a stop).***

- ***Support services to machines - oil supply, seal supply, cooling water, standby power, etc. must be available throughout any run down period to the point that the system is safe.***

- ***In some instances the support system is only required during transient operations, and where such systems do not affect normal running of the machine the vulnerability of the system can be seriously affected should operations continue with these support systems degraded.***

6.3 OPERATING POLICY

- ***A written operating policy should be established for each item, which would normally form part of an overall plant operating strategy. The operating policies will be derived from both economic and safety considerations.***

Operating policy should be consistent with : -

- Plant hazard study reviews which may have identified operating requirements to protect against hazards associated with equipment.

- Maintenance policy, which may require, for example, a machine to be shutdown for routine maintenance at specified intervals.

Operating policy should be supported by information on equipment hazards and care, and operating instructions to include start up, normal operation, shut down and emergency shut down. Manufacturers' operating requirements should also be incorporated into operating instructions. Tick-off sheets should be completed for key / critical stages in each instruction. Written instructions and actual operating practice must be consistent.

Operating policy should include : -

- The running of multiple / standby / spare machines (Where availability is required for safety reasons periodic test runs are expected).

- Induction and refresher training of operating teams in the hazards associated with equipment and the importance of adhering to operating policy and instructions.

- Action to be taken in abnormal circumstances.

Responsibility for the regular review of operating policy and writing operating instructions should be defined locally.

Auditing should be established locally to check compliance with operating policy and its instructions.

6.4 OPERATING PRACTICE - NORMAL RUNNING

- ***Main machine systems are complex entities, the design of the system will have been developed to provide protection and performance monitoring of the systems. The information from such systems will be displayed or recorded in a variety of ways, the operating team should be aware of the information available and be able to identify variations from normal performance.***

- ***Complex machines are designed with inherent safeguards; this should cause machines to fail-safe. In some cases this will not prevent machine damage, with inspection or repair required before restarting the machine.***

- ***A fundamental requirement is that the machine protective systems are fully functional, Manufacturer's operating instructions in some cases provide the specific warning that shut down devices must not be bypassed, or wired around, as they are incorporated to prevent personal injury and damage to the equipment.***

6.4.1 Operational Monitoring - Machine Systems

Information normally required for monitoring includes: -

Process Conditions

Operational Monitoring	Gas Turbine	Centrifugal Compressor	Recip Compressor	Pumps	Motors	Diesel Engines
Inlet / outlet temps	Y	Y	Y			
Inlet / outlet pressure		Y	Y	Y		
Power draw / fuel flow	Y	Y	Y	Y	Y	Y
Flow forward / recycle		Y	Y	Y		
Minimum flow	Y	Y	Y	Y		
Process density / MW		Y	Y	Y		
Speed	Y	Y		Y		Y
Process feed density / Mole Weight / contaminants		Y	Y	Y		
Process feed availability		Y	Y	Y		

Machine Conditions

Machine Monitoring	Gas Turbine	Centrifugal Compressor	Recip Compressor	Pumps	Motors	Diesel Engines
Speed	Y	Y	Y	Y		Y
Vibration levels	Y	Y	Y	Y	Y	Y
Bearing temps	Y	Y	Y	Y	Y	Y
Seal system flow / pressure		Y	Y	Y		
Lubrication oil flow / pressure	Y	Y	Y	Y	Y	Y
Oil supply level	Y	Y	Y	Y	Y	Y
Cooling water flow / temp		Y	Y			Y
Oil filter condition	Y	Y	Y			Y

The operators should be aware of the normal condition for all the parameters monitored, the point at which alarms will be activated, and the procedures and program of activities to take on identifying a deteriorating trend, or at the point of alarm. All actions need to be timely and an indication of the response to alarms should be identified.

Where monitoring of the system condition has led to a machine trip, a process should be available where by the actions to diagnose the cause and rectify the fault with appropriate integrity testing prior to machine restart are identified.

A machine trip on high vibrations will bring the machine to a stop. Once shut down the fault condition is cleared. Diagnosis is required prior to restarting the machine to show the cause of the trip and action required to prove the system. Restarting the machine with an inherent fault may lead to significant machine and collateral damage, particularly where the protective system may, by design, be switched out during the start-up process.

The conundrum here is that the machine is often at a higher risk of damage during start up, however the capability of the monitoring or protective system is such that to allow the starting process to be complete these must be switched or timed out. An examples of this is with vibration monitoring where there is a typically 3 second delay built in to protection systems at start up to avoid overcome initial rotor vibration or movement. Where torque protection is used with electric motors the starting torque may be 3 or more times the normal full load value to allow the machine to accelerate to full speed.

Checks prior to starting any machine must be rigorous to ensure the machine starts up successfully.

6.4.2 Operator Patrols

Routine patrols on machine installations provide facility operators with direct feedback on the general condition. Non conformance can be identified from a physical view of machine condition which can anticipate the diagnosis provided by the monitoring systems. Unmanned installations require significantly more sophisticated remote monitoring for effective / safe operation.

LOOK / LISTEN AND FEEL and SMELL are key senses for the operator

During Plant tours the operators must be aware of additional personal protective equipment requirements. Machines are sources of high noise levels, and leaks of potentially dangerous vapours and gases.

LOOK

Knowledge of the equipment is essential to allow identification of change to the physical configurations. The operator should be especially aware of the need to report the following:

Leakage - oil / water / process fluid / service gas
Breakage - disconnected cables / fittings.
General observations - dirt / debris build up / over activity of control valves.
Abnormal local instrument readings. Burned paint. Ice or condensation on a pipe (or lack of it)

LISTEN

Awareness of normal sounds from the machine will allow operators to notice change. Reporting and investigation of change to be covered by appropriate procedure.

FEEL

Vibration monitoring should provide quantifiable information on the condition of the machine, but these only record the values at the measured points. Awareness of change through feel will add to the overall diagnostic ability. Care is needed on any contact with the machine, particularly for hot surfaces, or access to inappropriately guarded moving parts.

SMELL

Minor leakage and overheated surfaces may result in abnormal smell from the unit. Used in conjunction with other senses (including common sense) can give advance warning, or indication of other problems, and direct any further investigations.

Machines, such as Gas Turbine engines, are enclosed in a noise reduction enclosure. During machine operation entry into the enclosure is not advised. When the machine is off line a procedure must define the safe working practice to confirm and underwrite cessation of operations during the period of entry, and define the conditions under which it will be safe to enter the enclosure.

The restrictions on operators to view the machine in these circumstances gives a conflict with other requirements such as: -

Identification of fuel or oil leaks around turbines and compressors must lead to immediate action to eliminate the leak.

These conflicts should be recognised within the operating procedures and not left to discretion of local operating practice.

6.4.3 Operator Activity

During normal running operator activity will in the main comprise monitoring of instruments. There are a number of essential routines that will be required dependant on the installation. Operator routines must be identified in procedures with a clear indication on the frequency or requirement for the actions.

Typical actions would include: -

To monitor values and trends which may indicate a deteriorating situation.
Examples of this are increase in filter pressure drop, change in bearing temperature, loss of process pressure generation, higher power draw, etc.

Draining of knockout pots to avoid excessive build up leading to liquid carry over of disengaged fluid or condensate - and hence damage to machine

Stroking of control valves - operating steadily can result in jamming of control systems. Displacing the system in a controlled way can avoid sticking problems ensuring that the control system will respond when required. (Some systems can automate this, but still require the operator to initiate the sequence)

Filter cleaning

Sample collection

Where routine operator actions are required appropriate access should be provided. Observation of temporary fixes for unsuitable access will show where the routine is carried out with difficulty, where as evidence of dirt / debris build up will show lack of attention to the routine.

Machine specific activities would include:

Operator Activity	Gas Turbine	Centrifugal Compressor	Recip Compressor	Pumps	Motors	Diesel Engines
Priming				Y		
Blocked in running		Y	Y	Y		
Isolation valve operation / Closing speed		Y	Y	Y		
Conditions leading to accelerated corrosion		Y	Y	Y		
Freezing	Y	Y	Y	Y		Y
Cavitation				Y		
Leaks	Y	Y	Y	Y		Y
External damage						

Other activities will be determine by the detailed of the individual piece of equipment and reference to the information provided by the designer and manufacturer of the equipment need to be included in the operating instructions available to the operators with appropriate training to ensure familiarity.

6.4.4 Maintenance Activity

During normal running all activities may be carried out by one group, though individuals may have been given additional support training to undertake these more specialist tasks:

Maintenance activities required on machines and rotating equipment are detailed in the relevant part of Sections 3,4 and 5 of this Guide
Machine Condition monitoring (see also 5.12.1)

In addition to the on line monitoring equipment further measurements and observations would be recorded by the machine maintenance specialist.

Machine Adjustments and other Maintenance Activities

Major machine systems do not in general need significant invasive maintenance during normal operations. The control of activities should be such that when any circumstance requiring attention occur they are well documented, risks are identified and all such activities are well defined.
Some examples where activities may be required as a routine:

Trip Testing

- All protective and alert devices should be checked to identify hidden failure modes. The period should be calculated dependant on the reliability of the device and reliability required.
- All trip test methods should be clearly defined as well as the condition and control of operations during trip testing.

- ***Overspeed Trip testing may introduce a higher risk than normal operations. Control of conditions throughout these activities is paramount. Failure to achieve necessary control has resulted in fatalities due to catastrophic failure of the machine system.***
- ***Annex A contains a reported process aimed at providing the necessary control during overspeed trip testing***
- ***Risk assessments should be available for trip testing procedures, with necessary precautions identified.***

Risk assessments should be available for trip testing procedures, with necessary precautions identified.

Oil supply replenishment :-

Introduction of fresh oil may be required for a variety of reasons due to deterioration of oil quality, normal process loss (sour seal oil etc.).
Topping up due to other system leaks suggests enquiries as to the source of the leak and programme of rectification.

In all cases where oil is added to the system the quality and quantity need to be strictly controlled, with proactive verification that the material added is compatible in all ways to the system.

Oil has multiple uses within machine, rotating equipment and drive train sets; the wrong lubricant can have significant consequences to the performance of process sealing, gear train integrity, and capability of bearings within the machine train.

6.5 TRANSIENT CONDITIONS - START UP, SHUT DOWN, RATE OR DUTY CHANGE

- ***Changing the operating state of the machine may be an infrequent activity that requires the operating team to carry out a wide range of potentially unfamiliar tasks in a very intensive period of activity. Emphasis should be put on co-ordination of activity within the limited time frames.***

- ***At such time there is the potential to do serious harm to the equipment, and though many protective systems will remain active during these conditions, some by their design have blind spots, and others can be misled, bypassed, or made inoperable intentionally or inadvertently.***

6.5.1 Actions to Start up Machine System

The operating procedures to define a number of sequential / parallel activities to establish initial conditions on the machine, with associated supplies of services, enabling of protective systems, and processing conditions.

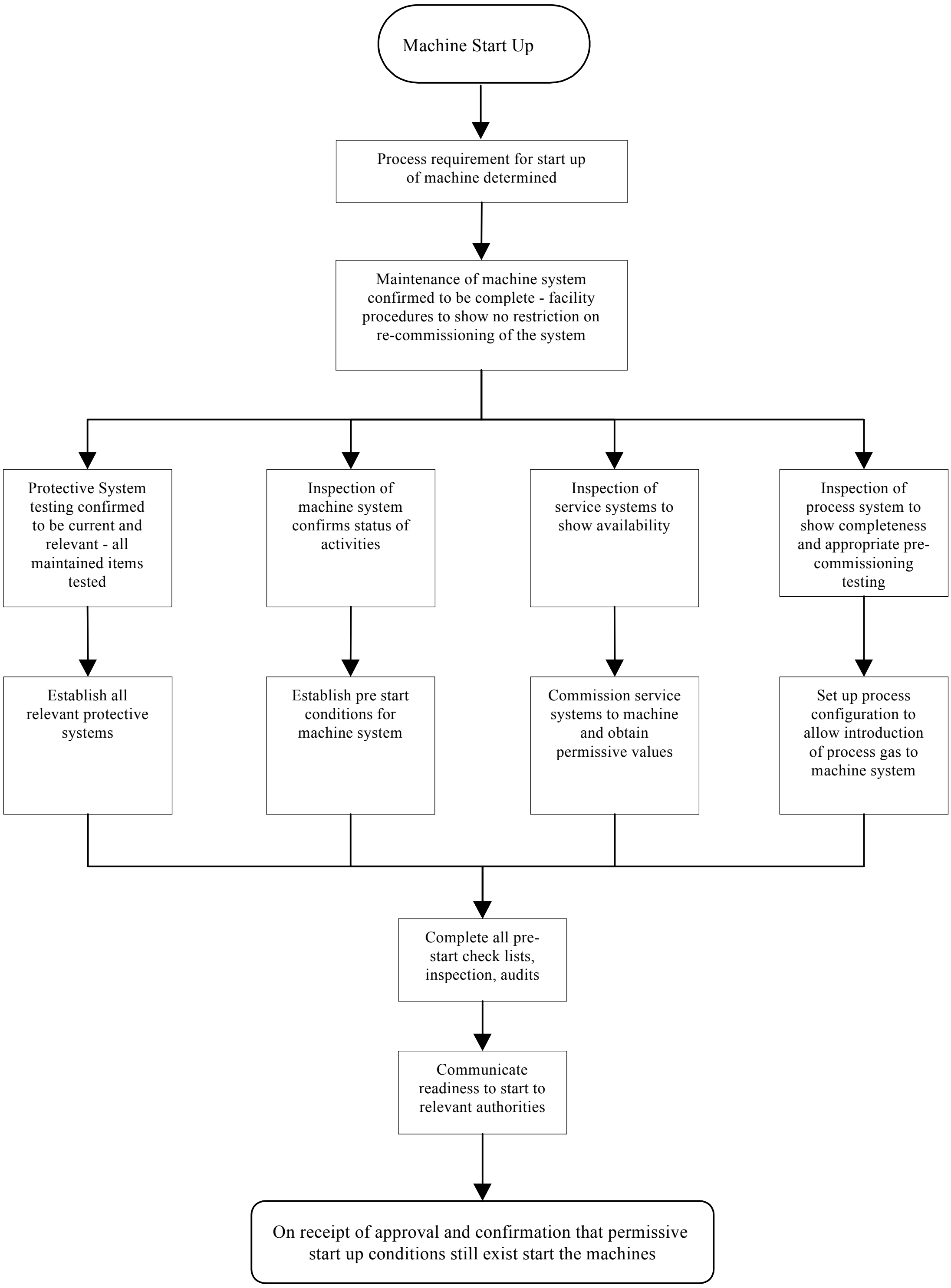


Figure 6 – 1 Actions to Start Up Machine System

6.5.2 Actions to Shut Down

Machines and rotating equipment must be shut down in a controlled way to prevent internal overload or damage.
The protective systems are normally designed for both process and emergency shut down. The protective devices should give indication of problems during the machine shut down and operators must examine anomalies and diagnose the response of the machine prior to restarting.

Failure to spot or diagnose anomalies will place a higher demand on protective systems during restart, which may lead to machine damage. (As noted earlier the protective system may, by design, not be engaged during restart)

The system must be shut down in a controlled way to avoid the potential to create transient surge pressure within the system, and the potential to allow reverse flow.
Once shut down the machine should be prepared for the period for which it is expected to be off line :-

For a short term off line – seal and oil cooling systems should be maintained, the machine left primed / under pressure against appropriate isolations – normally with the suction valve open and the delivery valve closed.

For longer term off line without the requirement for immediate restart :-

The machine should be fully isolated and drained, cooling water systems can be isolated and should then be drained. Maintenance routines established for periodic turning of the rotor.
Lubrication systems should be maintained, any ingress of water identified and rectified, for pump circulated systems, continued oil circulation is advantageous to equipment reliability.

Deterioration of the machine can be accelerated if the maintenance of the system is neglected during periods offline.

Support services must be maintained to the machine until system is in safe state.

Seal system services must be maintained until process conditions would not cause seal leakage.

Oil systems and machine slow turning (barring) should be maintained until the machine has cooled down.
Note that machines will have defined periods when the machine can be restarted. At other times, restarts should not be attempted due to possibilities for distortion or overheating. These periods are machine specific and guidance should appear in the operating instructions. Typical examples of this are :-

Electric motors, due to internal heating, will have a limit to the number of starts within an hour (or other defined period), this will be different if the machine is restarting from cold or after a period of operation.
The temperature within a compressor may cause the rotor to bow thermally once shut down. Although this may be countered by slow rolling of the machine, restarts may only be permissible either before the rotor has distorted or after it has recovered following a cooling period.

6.5.3 Actions to Introduce Duty Change

Machines and their drivers have a defined operating window. Changes which move the required duty outside this window may lead to machine overload, overstressing, instability, etc.

The operating limits for a machine system must be understood by the operating team. The limits should be defined with operating instructions, and reproduced on check sheets.

Changes which are known to move the machine outside the identified window must be documented and be assessed for risk.

SECTION 6 ANNEX A

Overspeed Protection Testing of Machines

The activity to test the over-speed protection on machines brings the machine closer to its limit of capability than normal operation. The conditions during such testing must be rigorously controlled to ensure that the testing itself does not cause the failure it is designed to protect against.

All personnel involved should have received documented 'hands-on' training, verified by testing. Initial and refresher training should include instruction regarding all components, including the turbine, governor, tachometer and the effect of the process conditions on trip testing. Manufacturer's data including the trip speed set point should be prominently displayed on or near all machines to be tested.

Documentation to be maintained on all machines where appropriate should include: Critical speed range, maximum safe operating speed, over-speed trip settings and tolerances (both mechanical and electronic if applicable).

Records should be maintained of all over-speed trip tests. A record of the previous test should be made available to all personnel performing an over-speed trip test. Records should include initial trip speed prior to any adjustments, a record of three consecutive trip speeds (within an acceptable range) in the specific order which they were performed.

Two independent speed measurement devices of different types should be used for verification of actual speed. Calibration of speed units should be current and per manufacturer's recommendations. Calibration records should be maintained by the operating unit.

At least three over-speed trips should be performed. They should be within the acceptable range, be consecutive and non-trending in order to constitute an acceptable test.Over-speed trip tests should be performed on all machines with the potential for over-speed on a scheduled frequency and whenever the machine is being re-commissioned or has been overhauled.

Mechanical over-speed protection devices such as trip linkages, bolts, weights, trip lever knife edges, springs, governor control systems etc., should be tested for freedom of movement by manual tripping prior to over-speed testing.
Over-speed trip tests may be performed with the turbine coupled or uncoupled to the driven equipment. Uncoupled tests require adequate control of the speed to be maintained. Over-speeding driver and driven equipment together is unusual and would not normally be preferred as it increases the power and kinetic energy available in extremis. Coupled tests have the advantage of providing better speed control but before commencing such tests. The maximum safe operating speed and power of the driven equipment and the turbine must be verified against design information to ensure they will not be exceeded during the tests.

Absolute control of the conditions must be maintained at all times during the over-speed tests to prevent uncontrolled speed excursions above the maximum trip speed. Control systems sized for maximum load conditions may not provide adequate control for trip testing, therefore alternative speed control devices must be considered to maintain control. When writing specific operational procedures each of the following should be considered: use of an appropriate sized recycle system to control flow, use of local speed control, possible step changes in energy supplied due to changes in barometric exhaust conditions, closing of multiple governing valves which may cause a non-linear acceleration.

Trip & throttle valves should be exercised on a periodic basis and immediately before each trip test. Individual organisations should determine frequency and procedure based on valve history and type.

SECTION 7 REVIEW PROCESS

SECTION 7.1 REVIEW PROCESS – VISITS

CONTENTS

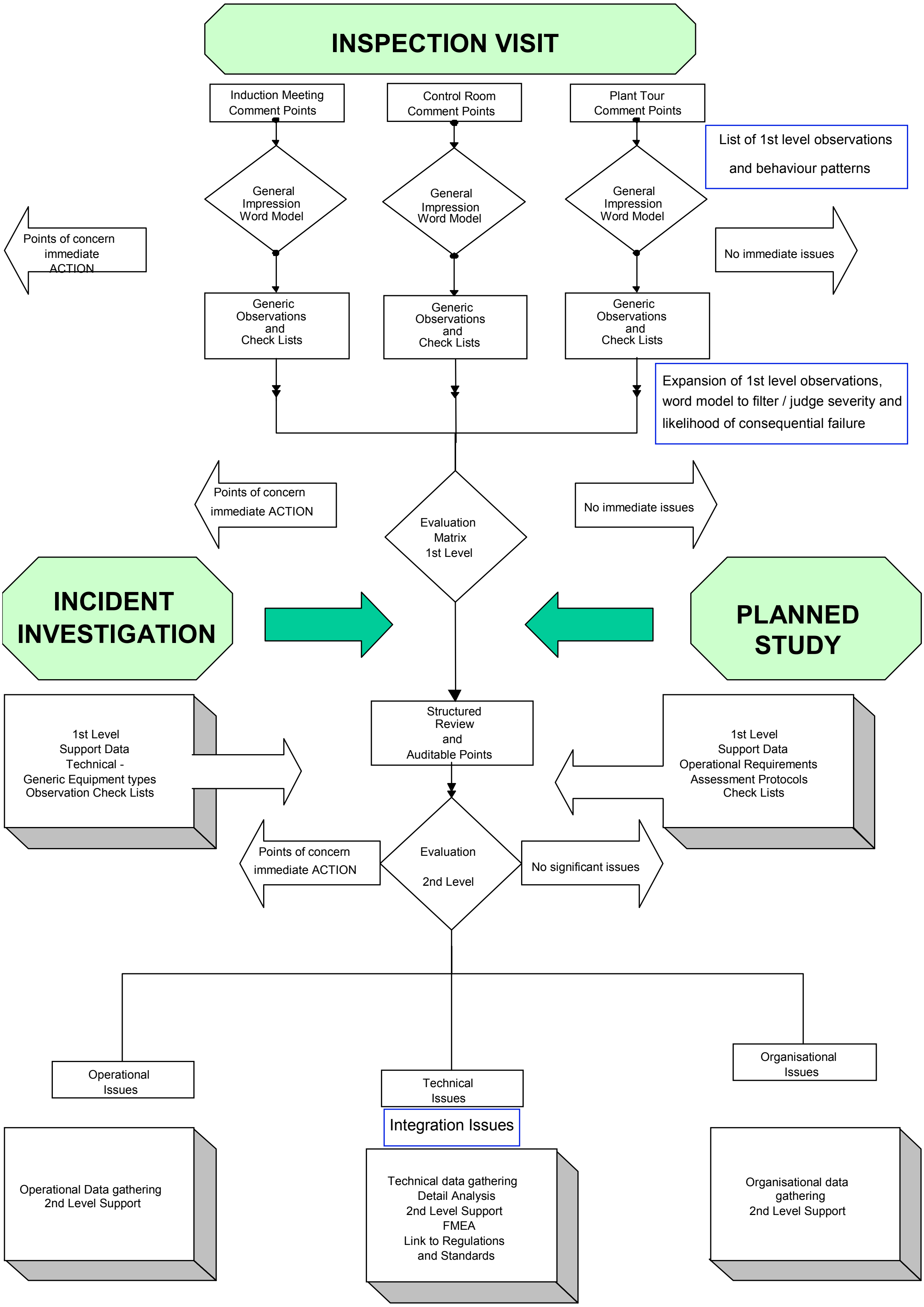
- ***The observations made on initial contact with a facility may not directly affect machine safety, but taken as a whole are the background against which a machine incident may occur.***
- ***In a good operating regime the potential incident will be recognised and controlled with no significant effect on the safety or operation of the platform. In a poor operating regime an incident may reach a dangerous state before its effect is recognised.***

7.1.1 GENERAL

Any competent and experienced inspector will gain a general impression of an installation when visiting for any reason. This impression will be coloured by that person's experience, expectations, mood, the behaviour of the hosts, even the weather at the time. Evaluation of impressions against standard "Word Models" should help to produce consistent feedback, permitting "ranking" of installations and operators. Less experienced inspectors may benefit from reading through the Word Models prior to a visit, to form an impression of what to expect on a well-run installation. All of the information gained during a visit can contribute usefully to the impression, but that which reflects the actual management process and the competence of the senior personnel, is probably the most valuable. The superficial condition of the equipment is not a good indication of the real safety of the operation. What is on paper is meaningless unless it is translated into action, as demonstrated by how things are done, records and operator knowledge.

7.1.2 USE OF GUIDANCE NOTES FOR AN INSPECTION VISIT

The guidance notes introduce the process which an Inspector might go through during a general visit. Documents have been prepared for training / reference purposes, suggesting topics and appropriate evidence of a satisfactory system. These have been split into 3 streams, being Induction / Meetings , Control Room, Plant Tour.


INSPECTION VISIT
Induction Meeting Comment Points
Control Room Comment Points
Plant Tour Comment Points
List of 1st level observations and behaviour patterns
General Impression Word Model
General Impression Word Model
General Impression Word Model
Points of concern immediate ACTION
No immediate issues
Generic Observations and Check Lists
Generic Observations and Check Lists
Generic Observations and Check Lists
Expansion of 1st level observations, word model to filter / judge severity and likelihood of consequential failure
Points of concern immediate ACTION
Evaluation Matrix 1st Level
No immediate issues
INCIDENT INVESTIGATION
PLANNED STUDY
1st Level Support Data Technical - Generic Equipment types Observation Check Lists
Structured Review and Auditable Points
1st Level Support Data Operational Requirements Assessment Protocols Check Lists
Points of concern immediate ACTION
Evaluation 2nd Level
No significant issues
Operational Issues
Technical Issues
Organisational Issues
Integration Issues
Operational Data gathering 2nd Level Support
Technical data gathering Detail Analysis 2nd Level Support FMEA Link to Regulations and Standards
Organisational data gathering 2nd Level Support

7.1.3 INDUCTION & MEETINGS

- ***The Safety Induction to an installation gives a first insight into the nature of the installation, the materials and processes and the management approach. A competent and complete induction not only shows the approach of the installation management, but gives the best chance that other newly introduced personnel are fully briefed and know how to behave safely. The induction should also identify the key hazards on the installation and the means for managing them.***

- ***Meetings with the OIM and the Safety Representatives give the opportunity to assess the management and employee commitment to a safety culture on board. Past incidents, how they were handled, learning points for the future can be covered. Future plans, changes to the operating regime, changes to manning system, can be discussed.***

- ***Any particular strengths or weaknesses should be noted, these may affect the safe operation / maintenance of all the on-board equipment including machines.***

Inspection Guidance Notes - Induction to Installation & Management Meetings

7.1.3.1 Induction

- ***A competent, professional induction into the purpose, operation, hazards and safety procedures of the installation. Use of video, projector or booklet to give visual impact, replay alarms/ tannoy messages. Clear identification of safe locations, refuges and areas requiring special access.***

- ***Test of understanding, completion of identity card & induction log.***

7.1.3.2 OIM Meeting

- ***An OIM who is in control of the situation, understands the purpose of the installation, the capabilities of the operating personnel and his / her powers / responsibilities for safe operation.***

- ***A clear ownership of any outstanding safety issues for the installation or its associated units.***

- ***A clear forward view of safe operation and pro-active safety management.***

7.1.3.3 Actions from Previous Safety Review Meetings with OIM

- ***Any actions from previous meetings cleared. On-going actions with a clear forward programme.***
- ***Any difficulties notified to Inspection Authority for discussion with Inspector.***

7.1.3.4 Incident Report

- ***No major machine incidents. All relevant incidents reported in a clear and consistent format. No double reporting. No incidents (of which the Inspector is aware) non-reported.***

7.1.3.5 Safety Case

- ***All requirements (particularly relating to changes) of Safety Case in place. System in place to call up special cases support.***

7.1.3.6 Operating Programme

- ***Forward operating intentions within the scope of the Safety Case, plans in place for realistic contingencies. Plans allowing for the resources, weather & operating arrangements prevailing. Adequate level of availability of duplicated / redundant support & safety systems. Programme developed with operating teams & well communicated. Planning of operations to co-ordinate with other operating units in the field.***

Word Model for :- **Operating Programme**

Keyword	Example	Concerns
Acceptable	Realistic operating programme in place and known to operators.	Consider "reality check" of location / weather / intentions.
Indifferent	Operating programme is not clearly understood at all levels, may be optimistic. Relies on good weather, no contingencies. Has been imposed	Suggest a review process with outside / independent assessment of contingencies / alternative plans. Escalate with Senior

	rather than developed.	Management if OIM has no influence on programme.
Not Best Practice	No proper forward programme. "Waiting for onshore approval". Activities requiring fair weather in winter. Serious resourcing problems looming.	Escalate with Senior Management - potential for unplanned incident or serious personnel workload problems.

7.1.3.7 Maintenance Programme

- ***All safety tests & inspections up to date. All Actions / Learning Points identified & owned. No "common mode" failure risks apparent from test results. Forward maintenance programme consistent with operating programme. Plans allowing for the resources, weather & operating arrangements prevailing. New equipment / new operating patterns planned for. Plans for safe commissioning of hydrocarbon lines. Overhaul plans with effective isolation / de-isolation, hydrocarbon removal & reintroduction.***

Word Model for :-	**Maintenance Programme**	
Keyword	Example	Concerns
Acceptable	All safety tests & inspections up to date. Forward maintenance programme matches operations needs.	Is the data shown real or cosmetic. Follow up examples where an independent check is possible.
Indifferent	Slight problems. A few tests / inspections deferred. Maintenance programme does not match operational needs.	Check that deferrals have had a risk assessment carried out & recorded. Check if situation is temporary or getting worse.
Not Best Practice	Serious problems with safety tests & inspections. No effective forward programme. Testing system & records in disrepute. Maintenance programme has not been produced or is awaiting approval / funding.	Is there the potential for major safety checks having been missed or faked ? Press for independent validation of key inspections. Escalate to clear causes of delay.

7.1.3.8 Safety Representatives

- ***A group of people representing a reasonable cross-section of the personnel on board, in terms of skills, groups employed, experience in the industry / on that installation. A commitment to a safety culture without either being petty or completely in awe of the operator. Recognition that safety is a continuous process with shared interests & responsibilities, with management taking the lead role.***

7.1.4 THE CONTROL ROOM VISIT

- ***The Control Room is the operating hub of the installation, the state of the equipment and the behaviour of the operators will affect the safety of the entire installation. The age of the equipment, perhaps with a mixture of newer technology, will give some indication of the operating history.***

- ***The level of activity, and the number of / distribution of current alarms will give an indication if the present activities are normal and being well managed.***

- ***The "Permit to Work" system is the safety link between the Operating and Maintenance groups, the system must show evidence of being comprehensively and intelligently applied. This particularly applies to multi-functional jobs which extend for more than 1 shift.***

7.1.4.1 "Permit to Work" System

- ***All work not covered by normal operating instructions, done under PTW system. All personnel understand how to use the system. Controller can clearly track each job and show closure. Effective handover of "open" jobs. Permit is reviewed if circumstances change.***

Word Model for :- **"Permit to Work" System**

Keyword	Example	Concerns
Acceptable	All appropriate jobs done on PTW system. System is well managed.	What evidence is available ? Does PTW apply to all groups ?
Indifferent	Some difficulties or lack of understanding. Poor handover at shift change. Jobs extended for many days. Sign-offs missed. Hazards not fully identified.	Does personnel quality / experience, local care, make up for deficiencies ? Is situation getting better or worse ? Does OIM know / understand the situation ?
Not Best Practice	System in disrepair. Some groups not using system. Vague task descriptions. Permit sheets missing.	Does the OIM have a plan in place for recovery ? Do incidents indicate that an immediate warning is required ?

7.1.4.2 Control Room Operations

- ***Correctly manned, reasonably clean & tidy, all display systems working, few / no alarms permanently in. Operators paying attention to job in hand, aware of visitors but not distracted, introduction of visitors to key operators. Description of operation in hand, state of the plant, any changes being managed.***

Word Model for :- **Control Room Operations**

Keyword	Example	Concerns
Acceptable	Tidy control room, adequately manned, operators concentrating on job in hand.	Are there other control rooms on this installation / complex ? Are they similarly well managed ?
Indifferent	Too few operators paying attention to the job. Undermanning. Use of control room as a social centre. Modifications & other distractions.	Does the incident report indicate a real problem ? Is this the normal situation or a temporary effect e.g. from refurbishment work ?
Not Best Practice	Operators not generally in control. Control room sometimes unmanned. Faulty displays. Many permanent alarms. Air of panic.	Do operating instructions permit empty control room - cause for immediate warning ? Does OIM have action plan for hardware problems ?

7.1.4.3 Technology / Equipment

- ***Technology relevant to the age of the installation. Effective labels on displays, pens / charts working, display screens clean / viewable / no flicker. Controls properly labelled / keyboards with legible characters. Logical layout of controls relating to process route / modules / on & off- platform equipment. Operator workstations permit all necessary controls to be reached / viewed readily without strain or risk of inadvertent operation. Alarm panel windows located / lit for clear viewing. Ventilation / air conditioning adequate for effective working. Smoke / gas doors & windows undamaged & working.***

Word Model for :- **Technology / Equipment**

Keyword	Example	Concerns
Acceptable	Control room layout & equipment functional and well labelled. Display screens are clear & easy to view.	If control room is new - do operators understand it ?
Indifferent	Control room layout compromised by modifications. Layout illogical or cramped. Poor labelling in some areas. Alarm panels awkward to view.	What plans does OIM have to improve the situation ? Is this temporary ?
Not Best Practice	Control room operability severely compromised by redundant and badly located instruments / screens. Some equipment obscured, screens not	What plans does OIM have to improve the situation ? Are operators really in control ?

working. Operators having to stand on boxes.

7.1.4.4 "Tour Guide"

- ***One or more operators showing the Inspector over the selected parts of the installation. "Guide" shows working knowledge of the installation, wears / carries correct PPE & checks same on Inspector. Advises Inspector of what activities are taking place, drawing attention to those which are unusual. Chooses route(s) to maximise view of operations, condition of equipment, minimise interference. Does not apparently avoid potentially "difficult" locations / operations. The behaviour of the "Guide" shows a positive approach to safety rather than blind understanding of rules.***

Word Model for :-	**"Tour Guide"**	
Keyword	Example	Concerns
Acceptable	Looks after Inspector & wants to help promote safe working.	Has he been briefed on current operations ? Can he spare the time ?
Indifferent	"Neutral" operator trying to steer inspector away from trouble. Does not talk. Chooses routes away from working areas. Wants to hand inspector over to job supervisor.	"Tour Guide" lacks confidence, is this general in operating team ? What is age / experience profile of the team ?
Not Best Practice	Hostility / conflict. Pours out petty complaints. "Tour Guide" seen as a punishment duty.	Is this person representative of the team ? What does incident report show ? Are the complaints petty or a real concern ?

7.1.4.5 Culture

- ***A competent, professional induction into the purpose, operation, hazards and safety The "culture", as seen from meetings, tours, operations, indicates an intelligent and co-operative approach to working safely. Work is planned in a safety-aware manner and carried out to the plan. The plan is revised as circumstances change, the necessary time is taken to review the safety provisions. There is a clear recognition that Safety (like Quality), is not a "bolt on" activity but is most (cost) effective when it is a totally basic and integrated part of doing the job. "The Rules" are not used as an excuse for why something has not been / cannot be done. There is pride in having contributed to a safety review, or found a safer design / method.***

7.1.5 THE PLANT TOUR

- ***A Plant tour of an installation provides the opportunity to gain an insight into the operating context in which machines are used and how well the activities are marshalled.***
- ***There are a number of detailed points that can be observed during the Plant tour, the attached guidance gives a logical structure for these observations.***
- ***The following pages initially provide an overview of such observations and how the activities seen may impact on the safety of the facility.***
- ***The overview is supported by a structure of more detailed observations and identifies particular points which would provide evidence to direct further inspections.***

7.1.5.1 Principles of Machine Integration

- ***Need for ability to adjust / control / maintain the item safely without putting persons at risk.***

Word Model for :-	**Principles of Machine Integration**	
Keyword	Example	Concerns
Acceptable	Operational controls and associated valves clearly identified and labelled. All easily accessible, labels readable, local instruments readable.	Check incident report. Look for temporary access "aids", inappropriate access routes. Are instruments orientated to be readable?
Indifferent	Operational controls and associated valves identified and some labelled. All accessible but layout is difficult, labels readable, local instruments readable.	Check incident report - out of compliances may escalate to minor incidents. Look for temporary access "aids", inappropriate access routes. Are all necessary controls used, difficult access may result in valves left open / not closed. Are instruments orientated to be readable? - check reading sheets to see if readings actually taken.

Not Best Practice	Operational controls and associated valves not identified and few labelled. Access is difficult, labels difficult to read, local instruments unreadable, or broken.	Minor incidents noted in log sheets - incidents may escalate due to poor access. Look for temporary access "aids", inappropriate access routes. Are all necessary controls used, difficult access may result in valves left open / not closed. Are instruments orientated to be readable? - check reading sheets to see if readings actually taken.

7.1.5.2 Materials and Product Hazard

- ***Products used and created during the use of the equipment must not endanger exposed persons' health.***

Word Model for :-	**Materials and Product Hazards**	
Keyword	Example	Concerns
Acceptable	COSHH assessment for all materials and products of reaction.	Material hazard identified, but potential for release not recognised.
Indifferent	COSHH assessment for main materials, minor process items not covered by assessment.	Material hazard not fully identified, potential for release consequence not to be recognised, or assumed to be tolerable.
Not Best Practice	No assessment of materials handled in process, or assumption that noxious substances created during process will not be released.	No action taken on release which may be toxic or flammable. In extreme this may produce major event situation, or additive to escalate minor event to major.

7.1.5.3 Ergonomic Issues

- ***Lighting - suitable for operations concerned.***
- ***Access issues - slipping / tripping/ falling on to / the machine. Hot / cold surfaces.***

Word Model for :- **Ergonomic Issues**

Keyword	Example	Concerns
Acceptable	Clear lay out for equipment, all access points / routes marked, and warnings of residual risks.	Infrequent operations may not be covered, issues on start up / shut down of machines. Essential operations possible in safe and timely way.
Indifferent	Design of system was reasonable, degraded by maintenance / modification / housekeeping standards.	Not ideal working environment, may place higher demand rate on machine protection systems, or results in damage prior to protective actions, and limited potential for operator injury (minor).
Not Best Practice	Poor initial standards, poor maintenance, confusing, poorly lit.	Difficult working environment, places higher demand rate on machine protection systems, or results in damage prior to protective actions, and potential for operator injury (minor).

7.1.5.4 Handling of Equipment

- ***Machinery and components must be capable of being handled safely.***

Word Model for :- **Handling Issues**

Keyword	Example	Concerns
Acceptable	Lifting arrangements clearly marked - weights of significant items marked	Operational procedures for lifting to be in constant with LOLER requirements. Importance of type and application of lifting eyes recognised.
Indifferent	No identified lifting arrangements	Overload on lifting devices leading to hazard from dropped load.
Not Best Practice	No identified lifting arrangements and no obvious means to allow handing.	Damage to machine element during handling / injury potential for maintenance operators

7.1.5.5 Releases (gases or liquid)

- ***No sign of releases of gas or liquids. No evidence of repairs to joints or seals. Drip trays / collecting bottles are in place for known drip points (e.g. sample points, certain machine seals) and are not full. No oil absorbent packs under equipment (but may be available in local locker). Gas sampling / warning systems in good order, not covered or disabled.***

Word Model for :- **Releases (gas or liquid)**

Keyword	Example	Concerns
Acceptable	No identified releases. No oil marks under bearings / seals.	Check incident report. Look for repairs on joints/ small bore pipe.
Indifferent	Minor releases , non-hazardous materials only, liquids being collected. Quantity being monitored. Water / lubricating oil flanges dripping. Full bucket hanging on sample valve. Use of oil absorbent pads.	Query material, quantity, disposal route. What are repair plans ? Are things getting worse ? Are any toxic/ highly flammable materials involved ? Consider formal warning to OIM.
Not Best Practice	Significant releases of Hazardous Materials. Oil spills on walkways. Areas hazard taped off. Pipe clips on hydrocarbon lines. Patch repairs on equipment. No drip trays (or damaged). Gas detectors wrapped in plastic bags.	Consider formal warning to OIM or need for an enforcement notice Barrier off particularly difficult areas. Move up next visit timing with review action.

7.1.5.6 Smells / Odours

- ***Faint smells close to equipment (hot lubricating oil), little or no hydrocarbon smell. Accommodation / control room smells fresh, not damp / musty suggesting corrosion. Wind direction may give smell from flare / vent booms.***

Word Model for :-	**Smell / Odours**	
Keyword	Example	Concerns
Acceptable	No detectable smell in open areas. Slight smells inside enclosures.	
Indifferent	Localised smells around seals or valve glands. Smelly inside modules, close to valves or machines. Open containers of chemicals / solvents. Accommodation / control room ventilation ineffective, stuffy or smelly.	Ask OIM plans for improvement.
Not Best Practice	General smell of hydrocarbons. Enclosed areas overpowering, lack of ventilation. Some valve gland leaks can be seen/ heard. Panels removed / doors propped to increase ventilation. Control room windows open. Additional portable fans in place.	Consider formal warning to OIM or need for an enforcement notice Barrier off particularly difficult areas. Move up next visit timing with review action.

7.1.5.7 Fire Protection / Prevention

- ***Operation & Maintenance covered on Op. & Mtce. plans. PTW's cover fire precautions, possible effect of job on protection systems. Fire walls / doors undamaged. Fire detectors / alarms / extinguishers in place & in test.***

- ***Work in progress does not block escape routes or prevent fire doors closing.***

Word Model for :-	**Fire Protection / Prevention**	
Keyword	Example	Concerns
Acceptable	Plans and equipment in place & being maintained	Make random check on inspection dates, equipment location vs. plan.
Indifferent	Some compromises. Temporary pipes / cables through fire doors. Extinguishers moved to cover jobs in progress. Small holes in fire walls.	Ask OIM plans for improvement. Are things getting better or worse ?
Not Best Practice	Serious breaches of safety. Fire doors missing or badly damaged. Fire extinguishers missing. Burning / welding sparks not contained.	Consider formal warning to OIM. or need for an enforcement notice Shut down modules with breached fire walls. Move up next visit timing with review action.

7.1.5.8 Noise / Acoustic Enclosures

- ***Control room / accommodation well insulated, normal conversation possible. General plant areas permit conversation at close range without shouting. Noise protection areas marked, acoustic hoods well sealed and doors close properly. Acoustic enclosures marked for PTW to enter. Correct ear protection available & being worn.***

Word Model for :- **Noise / Acoustic Enclosures**

Keyword	Example	Concerns
Acceptable	Noise areas well marked. Access controlled. Noise levels outside noise areas are acceptable.	Check for appropriate use of hearing protection. Are any particular employee groups at high risk ?
Indifferent	Some areas where noise is excessive. Some signs are inadequate. Easy to walk into noisy areas without warning. Tendency to shout to communicate.	How good is training / induction ref. noise ? Discuss with OIM, look for improvements in signage.
Not Best Practice	No control over access to noise areas, very noisy areas not marked. General tendency to work without ear protection. Ear protectors difficult to obtain. General requirement to shout. Control room too noisy for normal conversation.	Warn OIM of potential for hearing loss claims, incidents caused by poor communications. What is programme for improvement ? Urgent requirement re control room noise level, issue of ear protection.

7.1.5.9 Dirt / Corrosion

- ***Working floor areas / tops of beams are clean. No areas of general corrosion on structural steelwork or modules. Stairways and handrails in good condition. Pipework and in particular pipe supports without major rust stains. Pipe hangers not designed as water traps. Air filter systems / ductwork in stainless steel / plastics.***

Word Model for :- **Dirt / Corrosion**

Keyword	Example	Concerns
Acceptable	Clean facility.	Look for corrosion under lagging, behind cladding / finishes, on pipe hangers.
Indifferent	Some dirty corners. Some waste bins overflowing or being used for the wrong purpose. Rust collecting in odd corners. Some rusty cladding & pipe supports. Flat surfaces covered in dirt.	Ask OIM for improvement plan. What is pipe & hanger inspection plan / status ? How are working areas kept clean ?
Not Best Practice	Generally dirty. No waste bins. No mats at doorways to accommodation / control rooms. No indication of cleaning programme. General corrosion on structure & pipework. Failed pipe hangers.	Advise OIM of concern & state requirement for improvements. Are any hydrocarbon or toxic materials lines affected ?

7.1.5.10 Debris

- ***All working materials in correct containers / laydown areas. Bins to collect waste material. Separation of oily waste. Effective system for compacting and storing waste for shipment.***

Word Model for :- **Debris**

Keyword	Example	Concerns
Acceptable	Lay-down in bays only	Check trip hazards, lighting, access.
Indifferent	Generally slightly untidy. Some loose items lying around. Some lagging & cables loose. Rubbish collecting inside skids.	Ask OIM for improvement plan.
Not Best Practice	An obstacle course. Large amount of debris. Lagging & scrap parts lying loose. Accesses compromised.	Advise OIM of concern & state requirement for improvements. Discuss with Safety Reps.

7.1.5.11 Operating Practices

- ***Good co-operation between operators, carrying out equipment status checks (particularly isolation / vent / drain valves) prior to starting up machines. Effective monitoring of instruments, management of operation to keep within acceptable limits. Planned start-up of spare / standby equipment in anticipation of need. Good record keeping and handover between shifts. Effective logging of maintenance requests. PTW system functioning smoothly.***

Word Model for :- **Operating Practices**

Keyword	Example	Concerns
Acceptable	Operators show thought and control in their activities. No evidence of over-ridden alarms.	Does competence apply to all shifts ?
Indifferent	Some operators show lack of competence, some equipment being mal-operated. No pre-start checks. Equipment being started in a rush. Isolation valves not closed properly.	Query operator experience & training Query operating instructions for specific items of equipment against practice observed.
Not Best Practice	Air of panic. Operators rushing around. Mal-operating machines being ignored. Equipment being operated in "manual" mode. Wheel keys used to close valves. Instruments removed and blanked off.	Advise OIM of concern & state requirement for improvements. Discuss with Safety Reps.

7.1.5.12 Maintenance

- ***Clear handover of systems for maintenance, control of working areas, storage & management of spare parts. Good co-operation with shore side on maintenance records & spares procurement. Effective control of modifications & stock rotation of consumables (e.g. gaskets, filters). Good area clean-up after maintenance. Pre-checks and leak tests prior to hand-over for re-introduction of hydrocarbons.***

Word Model for :- **Maintenance**

Keyword	Example	Concerns
Acceptable	Most maintenance is planned. Jobs are completed tidily. Mtce. records are kept. Spares are re-ordered.	Is this just a special effort for your visit ? Check sample maintenance records.
Indifferent	Struggling a little, excessive proportion of breakdown work. Work part-done, awaiting spares. MTBF is dropping, spare parts not in stock or obsolete. Repairs take longer than necessary.	Are matters getting better or worse ? Ask OIM for improvement plan. Is an onshore visit required ?
Not Best Practice	Virtually all breakdown maintenance. Poor repairs, many incomplete awaiting parts. Reliance on "lame spare" equipment. Equipment left part repaired. Empty berths with valve isolation only.	Consider potential incidents from "lame spare" equipment. Advise OIM of concern & state requirement for improvements. Discuss with Specialist Inspector on return.

7.1.5.13 Personal Protective Equipment

- ***PPE being worn appropriate to the job in hand, reasonably clean and in good condition. Good labelling of areas where e.g. goggles, ear protection, are required. Suitable bins for disposal of used PPE / items for servicing or cleaning. Locations for individuals to store own items.***

Word Model for :-	**Personal Protective Equipment**	
Keyword	Example	Concerns
Acceptable	Correct PPE is available, issued & worn. PPE is clean and in good order.	Is this just an effort for your visit ?
Indifferent	A few problems. PPE is "borrowed" from others. Filters used beyond due time/ date. Dirty overalls.	Ask OIM for improvement plans. Query laundry system, note dermatitis risk.
Not Best Practice	PPE generally not being used. Much PPE not available. Jobs being done without PPE. PPE is damaged / very dirty. Overalls torn or contaminated with oil.	Advise OIM of concern & state requirement for improvements. Discuss with Safety Reps.

7.1.5.14 Behaviour

- ***People behave in a controlled & organised manner. Visitors treated respectfully & well managed. Behaviour is consistent across working groups / shifts. Stairs / doors treated with care, tools carried safely, use of harnesses, protective screens as required.***

Word Model for :-	**Behaviour**	
Keyword	Example	Concerns
Acceptable	People behave in a controlled & organised manner. Visitors treated respectfully & well managed.	
Indifferent	Some horseplay / unsuitable clothing. Visitors ignored / allowed to wander at will. A few lapses, a feeling that things are a little over-relaxed.	Advise OIM of concerns. Check incident report.
Not Best Practice	Behaviour totally casual, visitors pushed aside/ treated as a nuisance. Control Room treated as a social club. Instructions ignored/ treated with contempt. Bad language on radio calls.	Advise OIM of concern & state requirement for improvements. Discuss with Safety Reps.

SECTION 7.2 REVIEW PROCESS - EVALUATION

CONTENTS

7.2.1 WORD MODEL FOR INDUCTION / MEETINGS

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION	Develop by:
Induction	Induction misses key safety information. Inadequate checks for understanding. Misleading information shown.	New personnel or contractors will behave unsafely, put themselves and others at risk.	The contents and effectiveness of the Induction Process have not been reviewed	Identify and correct the errors in the content and delivery of the Induction Process	Addressing Organisational Issues
OIM Meeting	OIM is inexperienced, has not prepared well for meeting. OIM does not present a clear forward view on safety.	Lack of clear leadership on safety could lead to confusion and loss of morale. Potential loss of safety management control.	The OIM is not being adequately supported while gaining experience.	Identify and plan for additional support and training for OIM.	Addressing Organisational Issues
Actions from Meetings	Actions incomplete or lost. OIM unwilling to take responsibility for actions.	Known problems not dealt with, preventable incident occurs.	It is "acceptable" for actions to be "lost".	Ensure commitment to manage agreed actions to completion.	Consider Safety System Issues
Incident Report	Increasing number of incidents. Some indication of under-reporting or downgrading.	Root cause of incidents not recognised and dealt with. Larger incident which could be prevented.	Lack of commitment or capability in Root Cause Analysis	Establish Corrective Action Team with remit to analyse incidents.	Consider Safety System Issues
Safety Case	Installation operating outwith the provisions of the Safety Case. New equipment has not been assessed or notified.	Potential for an incident which has not been considered. Operating outwith the safe envelope.	Management are not aware / concerned that they are operating outwith Safety Case.	Limit operations to current Safety Case scope. Review Safety Case and update as required.	Consider Safety System Issues

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION	Develop by:
Operating Programme	Lack of effective forward operating program. Fair weather activities planned for winter.	Potential for incident caused by inadequate planning, activities rushed to beat bad weather.	Installation management are in "fire-fighting" mode and not looking ahead. May be waiting for data / sanctions from on-shore.	Establish forward programme with known data. Test validity of programme against fixed constraints e.g. maintenance outages.	Addressing Maintenance System Issues
Maintenance Programme	Lack of effective maintenance programme. Delayed inspections and safety checks.	Equipment is run beyond safe realistic limits. Trip systems fail and are not detected due to delayed test.	Breakdown maintenance only is possible due to lack of resources or commitment.	Establish forward maintenance programme covering at least safety-related inspections & tests, and those overhauls with a secondary safety impact.	Addressing Maintenance System Issues
Safety Representatives	Safety Representative system is ineffective.	Loss of morale within operating & maintenance staff. Grievances & concerns build up, lack of co-operation.	Senior management are not committed to UK Safety Representative process.	Senior management to publicly affirm commitment and follow through to operations level.	Addressing Organisational Issues

7.2.2 WORD MODEL FOR CONTROL ROOM

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION	Develop by:
"Permit to Work" System	Faults in PTW system. Not all jobs covered, permits not closed off. Hazards not covered.	Possible major incident caused by inadequate isolation / de-isolation. Work on live equipment. Personal injury.	There is no system in place to audit the effectiveness of PTW system.	Implement audit process on effectiveness of PTW system for all activities.	Addressing Organisational Issues
Control Room Operations	Under or over-manning of control room. Faulty displays or alarms. Operators not in control.	Minor incident is allowed to escalate. Operators take totally inappropriate action, releasing hydrocarbons.	Lack of proper management of control room operation.	Carry out review of control room effectiveness and manning levels.	Addressing Organisational Issues
Technology / Equipment	Additional or modified equipment makes normal control activity difficult.	Potential mal-operation. Incident escalates.	The modifications to the control room have not been integrated into the original control room concept.	Carry out hazard assessment of additional equipment and re-locate as required. Remove redundant panels.	Consider Technology Issues
"Tour Guide"	"Tour Guide" is not confident or familiar with installation.	General standard of competence of operators may be poor, mal-operation. Poor incident management.	Shift manager cannot spare a competent operator from an over-stretched team.	Review manning levels, sickness / absence levels, turnover of personnel.	Addressing Working Environment Issues
Culture	Groups do not take care of each other. Operators blame "others" for problems.	Lack of co-operation during an incident. Mal-operation.	Management permit / encourage insular behaviour on the "divide and conquer" principle.	Review personnel / training policies, set up regular emergency exercises to demonstrate effective co-operation.	Addressing Cultural Issues

7.2.3 WORD MODEL FOR PLANT TOUR

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION	Develop by:
Principles of Machine Integration	Operational controls and associated valves, identification and access. Equipment accessibility and apparent maintained condition.	Minor incidents may escalate due to poor access.	Consequences may only be determined by system limitations.	Study to determine effectiveness of design standards, operating processes, and effectiveness of preventative measures.	Consider Technology Issues
Materials and Product Hazard	Assessment of materials handled in process, or noxious substances created during process to ensure that these will not be released.	Possible release which may be toxic or flammable. In extreme this may produce major event situation, or additive to escalate minor event to major.	Where high hazard material is being processed, appropriate standards must be applied.	For high hazard applications consequences of weakness in other area need to be tested in structured reviews.	Consider Safety System Issues
Ergonomic Issues	Lighting , access, danger from hot / cold surfaces	Immediate impact on operator safety. Machine issues arise from activities incomplete, in error, or not being carried out.	Concern for individuals, and may worsen other situations.	Consider as potential accelerator of worsening situation on topics covered in Structured Review	Consider Working Environment Issues
Handling of Equipment	Potential for mishandling of equipment during maintenance activities. Correct use and types of lifting equipment	Immediate impact on operator safety. Machine issues arise from mechanical damage - not expected to influence main protective systems.	Concern for individuals	Investigate through consideration of maintenance practices in Structure Review	Consider Maintenance system Issues
Releases (gases or liquid)	Significant releases of Hazardous Materials.	Barrier off particularly difficult areas.	Where high hazard material is being processed, appropriate standards must be applied.	Consider as potential accelerator of worsening situation on topics covered in Structured Review	Consider Containment Issues for enforced improvement or prohibition

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION	Develop by:
Smells / Odours	General smell of hydrocarbon.	Evidence of lack of control - look for improvement	Where high hazard material is being processed, appropriate standards must be applied.	Detect sources, prioritise for repair / improvement	Consider Containment Issues for enforced improvement or prohibition
Fire Protection / Prevention	Missing or damaged fire protective systems	Escalation of localised incident due to lack of containment.	Where high hazard material is being processed, appropriate standards must be applied.	Consider as potential accelerator of worsening situation on topics covered in Structured Review	Consider as Working Environment Issues
Noise / Acoustic Enclosures	Noisy areas with little evidence that appropriate PPE required or worn	Chronic injury to operators, consider issues on communications during incidents.	Concern for individuals	Investigate through consideration of noise aspects in Structure Review	Consider Technology Issues
Dirt / Corrosion	General build up of debris / corrosion.	May influence stability of larger items.	Poor housekeeping standards. No effective maintenance on structure	Survey for condition of steelwork, plan treatment programme	Consider as Working Environment Issues
Debris	Loose items / cables blocking access. Tripping hazard.	Tripping injury, blocked escape routes.	Lack of concern for safe access / egress	Establish programme / objectives to make & keep tidy	Consider as Working Environment Issues
Operating Practices	Obvious faults ignored, operating team not able to follow through activities	Escalation of minor event to incident.	Where high hazard material is being processed, appropriate standards must be applied.	Consider as potential accelerator of worsening situation on topics covered in Structured Review	Consider Operation / Maintenance Practice Issues

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION	Develop by:
Maintenance	Key operating and safety equipment vulnerable to failure due to other breakdowns	Compromised operations, incurring higher risk of system failure	Where high hazard material is being processed, appropriate standards must be applied.	Consider as potential accelerator of worsening situation on topics covered in Structured Review	Consider Maintenance Planning Issues for enforced improvement or prohibition
Personal Protective Equipment	Absence of consistent application of PPE	Minor injuries possible due to exposure to equipment hazards.	Concern for individuals, and may worsen other situations.	Consider as potential accelerator of worsening situation on topics covered in Structured Review	Consider Personnel Safety Policy
Behaviour	Uncontrolled behaviour, climbing on equipment/ handrails.	Unsafe acts, personnel injury, interference with safety systems.	Concern for individuals, and may worsen other situations.	Consider as potential accelerator of worsening situation on topics covered in Structured Review	Consider Personnel Safety Policy and Practices

SECTION 7.3 REVIEW PROCESS

– STRUCTURED REVIEW

CONTENTS

7.3.1 SUMMARY OF STRUCTURED REVIEW GUIDANCE TOPICS

- Core Knowledge
- Maintenance Policy
- Requirements for Operating Policy
- Hardware Protective Systems
- Requirements for Operational Monitoring
- Noise
- Equipment Guarding
- Labelling Of Equipment
- Maintenance Practices
- Statutory and Codal Compliance

- ***The objectives of the structured review are : -***
- ***To confirm that engineering equipment and associated systems are designed, installed and maintained in accordance with legislative requirements, good engineering practice and in a manner that ensures that they are fit for purpose for safe operation for a defined period.***
- ***To ascertain compliance with statutory requirements.***
- ***To ascertain that engineering teams are working to defined procedures, best practice, or appropriate relevant Site instructions.***
- ***To raise awareness of the necessary engineering knowledge, standards, best practice and to encourage staff to seek appropriate technical help, advice and training.***

7.3.2 GUIDANCE NOTES

The PUWER Regulations 1998 provide the requirements that must be met by operators of equipment in some cases these requirements can be associated with particular standards (e.g. European Norms). Where no standards exist the regulations require the operator to ensure appropriate measures are in place relevant to the issue noted.

The guidance note indicates, in 10 key areas, actions that would provide operators such assurance.

7.3.2.1 Core Knowledge Assessment Notes

Most supervisory and managerial jobs require knowledge of certain key SHE and equipment reliability and safety issues. This structured review topic looks at how these areas of corporate knowledge are transferred between individuals in the event of planned or unplanned role changes or transfers of responsibility. The way in which training and skills needed as a consequence of the change are identified and implemented is also covered.

Background and Legal Aspects

The PUWER Regulations 1998 require operators to be aware of specific risks, have appropriate information, and protection against specific hazards.

Retention of core knowledge by facility operators is essential to avoid repeated incidents, whilst no code or other legislation exists demanding the use of Job Safety Handover Notes they are a critical system for maintaining corporate memory. There have been incidents in the past, the worst of which have involved fatalities in which the loss of corporate memory has played a significant part.

System

A written system should exist which incorporates the following points :-

- Job Safety Handover Notes should be written for all line Production and Engineering Management jobs down to Supervisor level. (A two tier system with a Safety, Health and Environment dossier for a Production / Plant Area supplemented by key items for individual jobs satisfies this objective).

- The system should have an appointed owner.

- All Handover Notes should be reviewed periodically, e.g. annually, to ensure the most recent learning is included in them.

- Evidence should exist for each job holder to show that he / she has completed the Safety Handover programme for their job.

Content of Safety Handover Notes in Relation to Machines

The following points should be included :-

- All relevant local Codes / Instructions / Procedures should be referenced.
- Equipment operating / maintenance policy.
- Equipment protection systems.
- All significant past incidents on the plant involving machinery.
- Engineering process auditing systems.
- The function of support engineering groups.
- Critical Item Register /Technical Folders.

7.3.2.2 Maintenance Policy

A maintenance policy defines how individual items or generic groups of equipment are maintained in terms of policy (e.g. breakdown, preventative, predictive), by whom (e.g. local resources, specialist contractors, off-site facilities, service contractors), spares policy (e.g. unit spare, overhaul spares etc.), technical/design authority and failure investigation protocols

Background and Legal Requirements

The PUWER Regulations 1998 require operators to have assurance of suitability for purpose, keep equipment in good condition, and carry out appropriate inspections at suitable intervals.

The hazards associated with equipment must be considered and appropriate systems used to control the hazards. The approach through Equipment Registration may result in maintenance requirements for each registered item. These will have to be integrated into the maintenance policy for that item.

Establishing a Maintenance Policy

A maintenance policy should be established for each item of equipment. Both economic and safety requirements have to be taken into account in establishing this policy. Economic aspects should be derived from the plant output and run requirements which can be translated into an availability target for each item. For most chemical plants the key factor will be whether the item is spared or unspared. If the latter, reliability may be 'critical'. Safety aspects must be derived from Hazops, where available, or consideration of the hazards of that particular item of equipment.

For critical reliability or high hazard machinery, maintenance policy will normally include prevention and condition based elements. A detailed analysis of failure modes will normally be worthwhile.

For major machines the works based machines engineer should be involved in defining policy and approving procedures.

For spared equipment on low hazard duties a breakdown maintenance policy may be appropriate. However operational monitoring should be used to detect and reduce the extent of failures.

For all equipment, improvement maintenance should be practised. This is based on recording and investigating failures in order to determine the root cause and the designing out the failure mode.

Where economic, condition monitoring techniques should be used in lieu of a preventative or breakdown maintenance policy. This will normally apply to unspared or critical reliability equipment where the important failure modes can be detected.

Local Requirements

Each plant should maintain an up to date equipment list.

Maintenance policy should be recorded for each item.

Where there are complex maintenance requirements procedures should be written to describe the activities that have to be carried out by Plant personnel. In particular a lubrication schedule, and spare parts schedule (e.g. spare gearbox) should be maintained.

Responsibilities for reviewing maintenance policy and writing maintenance instructions should be established. An auditing process should be established to check that policy is being carried through to the work place and instructions reviewed in the light of findings.

7.3.2.3 Requirements for Operating Policy

Operating policy covers such issues as operating instructions and changeover philosophy for spared machines.

Background and Legal Requirements

Mal-operation of machines is a common cause of their failure, which may lead not only to loss of plant production and damage to equipment, but also to hazardous incidents.

There are no specific legal requirements for an operating policy. However, the requirements of the Health and Safety at Work Act and PUWER Regulations 1998 mean that the specific hazards associated with equipment must be identified and systems such as training, supervision, information and instructions shall be used to control the hazards.

Requirements

A written operating policy should be established for each item, which would normally form part of an overall plant operating strategy. The operating policies will be derived from both economic and safety considerations.

a) Operating policy should be consistent with :-

- Plant hazard study reviews which may have identified operating requirements to protect against hazards associated with equipment.

- Maintenance policy, which may require, for example, a machine to be shutdown for routine maintenance at specified intervals.

b) Operating policy should be supported by information on equipment hazards and care and operating instructions to include: start up, normal operation, shut down and emergency shut down. Manufacturers' operating requirements should also be incorporated into operating instructions. Tick-off sheets should be completed for key / critical stages in each instruction. Written instructions and actual operating practice must be consistent.

c) Operating policy should include:

- the running of multiple / standby / spare machines (where availability is required for safety reasons periodic test runs are expected).

- Induction and refresher training of operating teams in the hazards associated with equipment and the importance of adhering to operating policy and instructions.

- Action to be taken in abnormal circumstances.

d) Responsibility for the regular review of operating policy and writing operating instructions should be defined locally.

e) Auditing should be established locally to check compliance with operating policy and its instructions.

7.3.2.4 Hardware Protective Systems

Background and Legal Aspects

The basis for Safety for many equipment items is dependent on the hardware protective systems incorporated into the design to detect abnormal operation and, if need be, safely shutdown the machine and the plant.

Legal requirements incorporated in the Health and Safety at Work Act and, PUWER Regulations 1998 require us to identify and control against the specific hazards associated with the equipment.

The review to be concerned with particular aspects of Hardware Protective Systems on equipment while recognising that further in depth reviews will be required to consider the details of individual systems.

Requirements

Equipment hardware protective systems including relief devices, trip systems including overspeed and mechanical trips, alarms, anti-surge protection, and shutoff systems should be defined, registered and classified in accordance in accordance with agreed established procedures.

For machine systems requiring registration as Safety Critical Machines, the hardware protective systems should have established documentation including a Schedule of Protective Systems.

Such documentation should link the hardware protective system with the hazards which it is guarding against, the integrity required (need for redundant systems), the target fractional dead time, and defined test interval. In some cases Hazard Analysis may have been carried out.

Testing procedures, records, defect reporting, and other aspects of trip overhaul, control of defeats and over-rides, should all be in accordance with similar systems in operation for other plant protective systems. Documentary evidence supporting these procedures and aspects should include equipment protective systems.

7.3.2.5 Requirements for Operational Monitoring

Operational monitoring not only covers the collection of data, either by operator inspections or "DCS" systems, but also the protocols by which the data is monitored, analysed and used to identify corrective actions, the training and understanding of those collecting the data and the reference standards used in validation of the data.

Background

Machines are, on nearly all plants, the most frequent cause of maintenance problems leading to downtime. They are also one of the most likely contributors to loss of containment incidents.

However, by good ownership and care, the reliability can be greatly increased. Operational monitoring has a key role in firstly acting as an early warning system and also as a means of increasing the ownership of the machines.

Requirements

- All running machines should be visited on a regular basis. In most cases this would be carried out by Process Operators as part of a patrol.
- The people carrying out the visits must know what they are looking for, e.g. excessive noise, seal failures, empty oil feeders.
- A means of proving that the visits took place should exist. Usually this is in the form of a patrol sheet on which the items to be inspected are listed. The person carrying out the inspection ticks against each item, makes any comments and signs the form.
- Key requirements for machines should also be checked, e.g. is the flush on, cooling water on, etc.
- Key readings should be taken as appropriate and recorded, e.g. bearing temps, oil levels, pressures, etc.
- The person taking these readings must have standard or normal valves to compare the readings with and know what to do if they are out of parameter.
- The sheets with the readings on must be stored in a logical manner.
- Management must be informed if a serious problem emerges from the data.
- Someone must own the responsibility for the system and ensure that it is followed and updated.
- In the case where data is automatically gathered by data logging systems, there must be a system for interrogating the data in order for trends / anomalies to be spotted.
- The system should be monitored through the use of local Auditing.
- The scope and frequency of inspections, extent and format of plant records for Major Machines should be defined.

7.3.2.6 Noise

This structured review topic looks at how individuals are protected against the adverse effects of exposure to noise.

Background And Legal Aspects

EEC directive 86/188 seeks to ensure that measures for hearing protection at noise exposure levels of 90 dB(A) are widely implemented and introduces measures intended to reduce hearing damage at lower exposure levels. In the UK the Noise at Works Regulations 1989, made under the Health and Safety at Work Act 1974, implement the EEC directive and as amended by The Offshore Electricity and Noise Regulations 1997 extended its use to off shore facilities.

Review Requirements

A Management Process must conform to legislative requirements, and should adopt good practices for elimination or reduction of the noise hazard.

There is a general duty to reduce risk of hearing damage to the lowest level reasonably practicable.

a) Identify workplaces and activities where noise levels may exceed 85 dB(A).

b) Assess exposure : -

- Job titles and individuals with unprotected $L_{EP,d}$ value > / = 85 dB(A) (Action level1).
- Significant noise sources within 90 dB(A) contours (Action level 2).
- Noise exposures from use of mobile / portable sources.
- Instances where peak sound pressure may exceed 200Pa (Peak action level).

c) Publicise Areas :-

- By map prominently displayed showing :-

(a) 90 dB(A) contour adjusted to conform with physical features, and where practicable, 85 dB(A) contours,

(b) advisory (unmarked 85 dB(A) areas).

- On site 90 dB(A) areas by "Wear Ear Protection" notices and, when notices alone are inadequate, red lines.

d) For 90 dB(A) areas, reduce as far as reasonably practicable noise emissions by technical means and exposure by organisational means.

Where significant noise sources exist then consideration should be given to application of noise enclosures (but in all cases where avoidance of one hazard might lead to introduction of others then appropriate measures must be taken to ensure that the overall risk level is considered. – e.g. Noise enclosure on a gas turbine needs careful consideration of fuel leakage within the enclosure.)

e) Where the likely daily exposure of an employee exceeds 85 dB(A), advise the employee of relevant noise sources and activities, risks, protection measures and responsibilities, and train in use of ear protection, and make suitable and efficient personal ear protectors available.

f) Ensure individuals with $L_{EP,d}$ > / = 90 dB(A) have hearing tests.

g) Maintain personnel records identifying individuals whose $L_{EP,d}$ has been or is > / = 85 dB(A).

h) Issue instructions, which are up to date, setting out requirements and responsibilities above.

i) Issue instructions setting out responsibilities and arrangements in respect of off plant noise.

j) Check that where practicable modifications do not increase existing background noise,

otherwise the increase is not to exceed 5 dB.

k) Monitor (a) and (j) above and keep permanent records.

Requirements for all Personnel

a) Wear ear protection within mandatory area and when using equipment tagged "Wear Ear Protection".

b) Fit and use noise reduction equipment correctly.

c) Report any defects in noise reduction or protective equipment.

7.3.2.7 Equipment Guarding

Background and Legal Aspects

HASAWA, PUWER Regulations 1998, Supply of Machines (Safety) Regulations places upon the suppliers and user of machinery an obligation to have a safe system of work so that people are protected from the risks associated with the machinery. Machinery Guarding often is a major element of the Safety System of work.

The definition, provision and maintenance of effective guarding required knowledge of the process in action, the people and the culture. Access for cleaning is often overlooked.

Once the risks of machinery are identified the requirement to guard must be appropriate to the risk assessed. The standards for guarding are now incorporated into a series of European Norm Standards. - For example BS EN 953 for the design standards required for guards.

Design of Guards

Prevention of contract may be by close guarding or area guarding. This choice will be made normally at the time of installation. It is necessary however to understand the philosophy of each in its application to a particular situation.

Guards must be robust, fastened to something solid and secure, i.e. requires a spanner or tool to remove

A number of documents exist which give guidance on detailed design aspects, such include (but not exclusively):

- BS 5304 : Code of Practice.
- BS EN 292 Part 2 /A1 1995– Safety of Machinery – Basic Concepts and general principals for design – Part 2 Technical principals and specifications.
- BS EN 414 1992 Rules for Drafting and presentation of safety standards.
- BS EN 953 1997 Safety of Machinery – Guards – General requirements for the design and construction of fixed and moveable guards.
- BS EN 563 A1 1999 Safety of Machinery – Temperatures of touchable surfaces – Ergonomics data to establish temperature limit value for hot surfaces.

Other standards are available as a series of Transposed Harmonised Standards covering design principals to support the Supply of Machinery (Safety) Regulations 1992.
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Inspection and Maintenance

Systems should exist to ensure that guards continue to protect people from the hazards.

All guards should be inspected at a frequency appropriate to the duty and plant conditions. The period may be a month and should not exceed a year. A guarding inspection should always be carried out after major maintenance on the area in question.

Particular care should be taken on the following aspects :-

- Guards left insecure.
- Signs of abuse, e.g. by poles used to clear hold ups.
- Deterioration due to environment.

A system should exist to ensure that following inspection, remedial action is taken promptly, recognising the essential safety nature of the work.

Evidence should exist to demonstrate compliance with the systems established.

7.3.2.8 Labelling of Equipment

Background and Legal Aspects

Inadequate labelling of machines has caused a number of serious accidents, including fatalities. Many other incidents of mistaken identity or missing labels have been recorded.

The PUWER Regulations require that work equipment is marked in a clearly visible manner with any marking appropriate for reasons of health and safety. The EEC Directive 89/665 specifies that work equipment must bear warning and markings essential to ensure the safety of workers. UK legislation through the Health and Safety at Work Act 1974 requires such information to be provided to ensure the safety of employees, and this is interpreted as requiring equipment to be clearly labelled to ensure correct identification.

Requirements

There is no universal numbering system, so to meet the requirements described above, the following guidelines should be followed :-

a) There should be an established numbering system for equipment on the plant including a planned procedure for generating new numbers when required. The system should be logical and easily understood. Operating and maintenance people should be aware of and understand the numbering system.

b) Each driven machine and, where required, each driving motor should have a number which is unique within that production area.

c) Equipment numbers should be clearly visible, painted on the item location, and also on the item itself, if necessary. In some cases it is important to identify machines in the

workshops, so the machine itself should be labelled. Where labels are attached to guards or noise hoods, the number should also be painted on the machine itself.

d) Emergency stop buttons should be clearly labelled with the same number as their associated machine. Special circumstances, such as auto-start machines, should have explanatory labels to warn of potential hazards.

e) There should be a routine procedure for checking labels to ensure that the standards of labelling is maintained, and evidence that this procedure has been carried out.

7.3.2.9 Maintenance Practices

Background

This Guidance note addresses the practices required for effective maintenance of machines. The PUWER 1998 Regulations require that work equipment is maintained in an efficient state, efficient working order, and in good repair. Equipment requires appropriate inspections before being put into service, where deteriation mechanisms exist at appropriate intervals, and following excursions which could cause deteriorations.

Training

Training appropriate to individuals is required for the purposes of health and safety. Refresher training or checks on understanding are required as well as initial training. Training needs to be recorded and its effectiveness assessed. The assessment may be by testing, questioning and observation, all by a competent, responsible person.

For machines, training should cover general maintenance principles and practice, such as the following :-

- Making and breaking of jointed connections.
- Bearing, seals, alignment, materials of construction, guarding.
- Critical items identification, and standards of maintenance required by the item.
- Retention of failed components for examination.
- Maintenance procedures and job method system.
- Handover of progress on uncompleted jobs, e.g. shift / days.

Specific machine requirements are covered by :-

- Instruction and practice on individual job instructions.
- Specialised off site training as appropriate (vendor, etc.).

Records Relating to Maintenance

Information such as the following, should be kept :-

- Lubrication routine performance.
- Machines dossiers (scope according to importance / complexity).
- - data sheets, drawings, makers manual.
- - assurance papers and certificates.
- - modification records.
- Results of Condition Monitoring.
- Overhaul reports.
- - work done, faults found, items replaced.
- Learning event reports.
- Job handover notes.

Working Practices To Be Reviewed

Workshops

- Labelling of work in progress and machine component spares.
- Special tools identification.
- Information to hand and up to date.
- Appropriately clean working environment.

Maintenance Instructions. These need to cover :-

- Best maintenance practice, repair / reuse of components, special tools.
- Key dimensions, with tolerances, to be checked / recorded.

Lubrication

- Lubricant testing on large systems.
- Storage and labelling of lubricants.
- Disposal of used oil.

7.3.2.10 Statutory Compliance

Particular aspects of Statutory compliance are in part reviewed as part of the other topics more generally other relevant regulations include :-

RELEVANT LEGISLATION

1. The Health and Safety at Work Act 1974.
2. The Management or Health and Safety at Work Regulations 1992 (MHSWR).
3. The Provision and Use of Work Equipment Regulations 1998 complement MHSWR.
4. The Confined Spaces Regulations 1997.
5. The Noise at Work Regulations 1989.
6. The Supply of Machinery (Safety) Regulations 1992.
7. Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations 1996 - ATEX Directive.
8. The Electricity at Work Regulations 1989.
9. The Pressure Systems and Transportable Gas Containers Regulations 1989.

7.3.3 REVIEW RATING ASSESSMENT

The evidence from the review should be assessed using consistent criteria. The following categories and criteria have been defined for the review.

The assessment of the topic considers the process by which the topic is managed, and then how effectively is the system applied. This assessment is considered in 4 stages.

Stage 1	=	Does the system exist?
Stage 2	=	What is the quality of the system?
Stage 3	=	Evidence of adherence to the system?
Stage 4	=	Is the system properly managed?

The assessment at each stage should be an overall view of the situation observed.

1	Very Poor	Immediate Corrective Actions needed in more than one area.
2	Poor	Immediate' Corrective Action needed in one area.
3	Development required	No Immediate Corrective Action needed, but longer term action required to improve general standards.
4	Development advised	Some Corrective Actions desirable but not essential.
5	Requirements met	No Corrective Actions recommended.

		Stage 1	Stage 2	Stage 3	Stage 4			Overview
1	Core Knowledge							
2	Maintenance Policy							
3	Operating Policy							
4	Hardware Protective Systems							
5	Operational Monitoring							
6	Noise							
7	Guarding							
8	Labelling							
9	Maintenance Practices							
10	Machines Legislation							
					Overall			

7.4 HAZARD OBSERVATIONS

7.4.1 PUMP OBSERVATIONS

- ***The table gives examples of Observations which would indicate Not Best Practice in the operation / maintenance of any Centrifugal Pump on a significant duty.***

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Equipment	Vibration	High vibration levels, particularly if unsteady	Machine damage. Pipework / instrument damage.	There is damage to the machine rotor, or pump is being operated at low flow.	Check plant flow, remedy if required. Carry out frequency analysis of vibration signals. Identify cause and plan remedial action.
	Baseframe	Machine feet moving on bed (Cracked paint or "panting" - movement)	Misalignment. Possible major failure.	Holding down bolts loose or broken	Tighten bolts. Check freedom of sliding connections. Check for added constraints which should not be there
	Process flow	Process flow outwith normal range	Overload. Pump trip.	Operators may be struggling to control the process.	Review operating instructions re flow control.

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
	Bearing temperatures	Bearing temperatures high (alarms in, check temperature instruments)	Bearing failure. Machine trip. Seal failure (as consequence).	Bearing or lubrication fault has not been identified by operators	Root cause analysis, appropriate remedial action
	Bearing temperatures	Burnt paint on bearing housings	Fire. Imminent machine failure.	Machine has been (if now cold) or is close to a major bearing failure. Temperature sensors faulty?	If hot - immediate unloading / controlled shutdown. If cold - avoid load changes, monitor closely while looking for cause.
	Oil spray	Sealant or oil spraying.	Bearing failure. Machine trip. Seal failure. Process fluid release.	High pressure fluid being released through narrow crack which could enlarge	Monitor closely. Identify fluid and source. Remove source of pressure. Repair.
	Reverse rotation	Installed NRV on pump discharge with evidence of historic maintenance	Failure or partial failure of NVR may result in reverse rotation of pump. Possible bearing failures / uncontrolled speed /	Hidden failure mode requiring investigative inspections. Lack of appropriate maintenance can lead to destructive pump failure with associated unrestricted loss of inventory	Maintenance program required to address hidden failure mode, appropriate inspections for required standards
	Overspeed				
Maintenance	Guarding	Guards missing	Personal injury	Poor working practices, lack of effective hand-over	Shut machine down or prevent access pending replacement.
	Temporary connections	Temporary flexible connections (small bore)	Loss of sealant system. Loss of lubrication. Loss of instrument connection.	Correct pipes have failed and been replaced with temporary ones.	Replace with correct hard pipe or suitable flexible. See 8/ above.
	Noise	Noise level is unsteady	Control problems. Thrust balance problems.	A fault in the control system, or gas in the fluid, is causing load changes	Investigate root cause of noise fluctuation
	Small bore pipework	Small bore pipework poorly supported, vibrating.	Pipe failure. Loss of sealant, lubricating oil, instrument connection.	Continued operation could lead to failure by chafing or fatigue.	Check if vibration levels are normal. Reduce vibration or improve pipe support (with damping material).

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
	Guarding	Guards loose / corroded	Personal injury.	Lack of care on routine inspections	Assess risk, plan repair or take more immediate action if appropriate
	Location / handling	Position of pump allows access for routine and normal maintenance.	Personal injury. Poor equipment reliability and potential for higher demand on protective systems.	Installations designed for limited size with restricted access may result in poor maintenance practices leading to reduced reliability.	
	Missing features	Incomplete maintenance with local gauges not fitted or out of commission, burn through protection not replaced, missing blanks on open ends	Additional emissions of hydrocarbons, immediate problems not detected with greater chance of development to more serious incident.	Poor working practices, lack of effective hand-over	Immediate report to control room. Immediate actions to bring system up to acceptable standard.
Operational	Instruments / displays	Machine and local instruments dirty	Poor operation. More likely to run out of operating limits.	Operators do not use (or trust ?) these instruments	Review operating instructions. Are local instruments required?
	Product leak	Strong smell of hydrocarbon / dribble or spray from joint.	Fluid release. Fire / explosion.	Uncontrolled hydrocarbon liquid release. Problems can be significantly greater on high pressure systems.	Immediate report to control room. Isolate remotely. Evacuate area at risk.
	Open ends	Pipe open ends with no blanks	Hydrocarbon liquid release if valve passes or is inadvertently operated.	Safety blank may have been left off through carelessness	Identify if the pipe should be blanked. Review instructions for relevant activity.
	Flexibles	Flexible connections	Potential failure	Flexible connections are easily damaged	If a flexible connection is necessary, it should be of an appropriate grade and on an inspection register.

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Relief devices	Relief devices isolated	Over-pressure. Pipe rupture. Explosion / fire.	Dangerous working practices, failure of PTW system	De-isolate or shut down. Investigate and correct failures in operating / maintenance philosophy
Seals	Drips of oil or sealant fluid	Seal or pipe joint damage - early indication of failure?	Problem could get worse and cause a failure	Identify source and monitor. Repair if appropriate.
Cavitation	Crackling noise from pump	Long term internal damage, some loss in pump performance	Operating duty changed either due to conditions, rate, or product pumped.	Ensure operators aware of longer term reliability issues

7.4.2 RECIPROCATING COMPRESSOR OBSERVATIONS

- ***The table gives examples of Observations which would indicate Not Best Practice in the operation / maintenance of a Reciprocating Gas Compressor.***

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Equipment	Vibration	High vibration levels, particularly if unsteady	Machine damage. Compressor trip. High vibration levels can cause loosening of machine and connection bolting leading to accelerating collateral damage. Vibration can result in fatigue damage to connections.	There is damage to the motion works. Loosening or fatigue of process connection may result in a significant emission.	Carry out frequency analysis of vibration signals. Identify cause and plan remedial action.
	Flexibles	Flexible connections	Potential failure	Flexible connections are easily damaged	If a flexible connection is necessary, it should be of an appropriate grade and on an inspection register.
	Bearing temperatures	Bearing temperatures high (alarms in, check temperature instruments)	Bearing failure. Machine trip. Mechanical damage (as consequence). Process gas release.	Bearing or lubrication fault has not been identified by operators	Root cause analysis, appropriate remedial action
	Noisy compressor valves	Clattering can be heard and felt local to valve(s)	Loss in performance. Valve could fail or damage valve cover.	Valves are damaged or loose.	Monitor vibration at each valve, identify severity, trend to check for deterioration.

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
	Baseframe	Machine feet moving on bed (Cracked paint or "panting" - movement)	Misalignment. Possible major failure.	Holding down bolts loose or broken	Tighten bolts. Check freedom of sliding connections. Check for added constraints which should not be there
	Oil leakage	Oil leakage or visible plume from oil system vent.	Loss of oil. Process gas in crankcase.	Check for damaged oil pipe. Oil fume could indicate a failed rod packing.	Monitor closely. Identify fluid and source. Remove source of pressure. Repair.
Maintenance	Open ends	Pipe open ends with no blanks	Hydrocarbon gas release if valve passes or is inadvertently operated.	Safety blank may have been left off through carelessness	Identify if the pipe should be blanked. Review instructions for relevant activity.
	Small bore pipework	Small bore pipework poorly supported, vibrating.	Pipe failure. Loss of sealant, lubricating oil, instrument connection.	Continued operation could lead to failure by chafing or fatigue.	Check if vibration levels are normal. Reduce vibration or improve pipe support (with damping material).
	Guarding	Guards loose / corroded	Personal injury.	Lack of care on routine inspections	Assess risk, plan repair or take more immediate action if appropriate
	Guarding	Guards missing	Personal injury	Poor working practices, lack of effective hand-over	Shut machine down or prevent access pending replacement.
	Temporary connections	Temporary flexible connections (small bore)	Loss of sealant system. Loss of lubrication. Loss of instrument connection.	Correct pipes have failed and been replaced with temporary ones.	Replace with correct hard pipe or suitable flexible. See 8/ above.
	Maintenance program	Formal maintenance programs required to cover inspections on key items	Deterioration of internal components may lead to catastrophic machine failure	Major machine damage may lead to a significant emission of process gas.	Maintenance strategy and program to be developed.

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
	Machine Valves	Un-controlled maintenance without formal documented procedures.	Major machine damage if incorrect fitting leads to machine gas locked	Major machine damage may lead to a significant emission of process gas.	Documented controlled maintenance program to ensure appropriate levels of care.
	Temporary connections	Temporary flexible connections (large bore)	Process gas release. Fire / explosion	Equipment being used in temporary berths / abnormal operating	Assess risk relating to fluids handled / duration of job / operator cover.
Operations	Process temperature	Process temperatures outwith normal range	Overload. Compressor Trip. Pipe blockage (hydrate?), change in gas composition.	Operators may not know potential consequence of change in gas composition or cooling fault.	Review operating instructions re temperatures . Check cooling system.
	Process temperature	Process temperatures outwith normal range	Failure or partial failure of the many machine valves will distort the operating performance in terms of temperature and/ or inter stage pressure of operation. Consequence can lead to lifting of relief valves and damage to machine.	Lack of awareness or knowledge about hazard may cause in appropriate changes to machine configuration, commonly to increase RV set pressure. To overcome RV flutter.	Inappropriate changes to machine will need immediate improvement. Increasing awareness of problem would be a development requirement for Operating team.
	Noise	Noise level is unsteady	Control problems.	A fault in the control system is causing load changes	Investigate root cause of noise fluctuation
	Instruments / displays	Machine and local instruments dirty	Poor operation. More likely to run out of operating limits.	Operators do not use (or trust ?) these instruments	Review operating instructions. Are local instruments required?
	Seals	Drips of oil or sealant fluid	Seal or pipe joint damage - early indication of failure?	Problem could get worse and cause a failure	Identify source and monitor. Repair if appropriate.

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Packing seals	Lack of action plan on leaking seals	Seal deterioration is progressive and normally identified and monitored - requires careful and prompt maintenance.	emission of hydrocarbon material into machine which overloads local venting arrangements.	Immediate report to control room. Improvements required.
Gas leak	Strong smell of hydrocarbon / sound of a leak.	Gas release. Explosion / fire.	Uncontrolled gas release	Immediate report to control room. Isolate remotely. Evacuate area at risk.
Isolations	No remote isolation valves, no program of testing or maintenance, actuators out of commission, sensors moved or pointing in the wrong direction	Effective operation of remote IV s key to safety integrity	Lack of awareness to hazards	Immediate report to control room. Improvements required.
Liquid draining	Absence of routines - normal monitoring and start up - and accessibility of suitable valves	Liquid locking of machine can lead to catastrophic damage.	Major damage to machine will result in emission.	Operating procedures needed to include draining in routine operations.
Relief devices	Relief devices isolated	Over-pressure. Gas release. Explosion / fire.	Dangerous working practices, failure of PTW system	De-isolate or shut down. Investigate and correct failures in operating / maintenance philosophy
Operating speed	For variable speed units acceptable speed ranges must be defined to avoid gas pressure resonances	Pressure pulsations can cause overpressure of machine or/ and associated equipment. Can also vibrations/ fatigue failures in associated equipment.	Operators may not know potential consequence of change in operating speed.	Immediate report to control room. Improvements required.

7.4.3 CENTRIFUGAL COMPRESSOR OBSERVATIONS

- ***The table gives examples of Observations which would indicate Not Best Practice in the operation / maintenance of a Centrifugal Gas Compressor.***

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Equipment	Vibration	High vibration levels, particularly if unsteady	Machine damage. Compressor trip.	There is damage to the machine rotor	Carry out frequency analysis of vibration signals. Identify cause and plan remedial action.
	Small bore pipework	Small bore pipework poorly supported, vibrating.	Pipe failure. Loss of sealant, lubricating oil, instrument connection.	Continued operation could lead to failure by chafing or fatigue.	Check if vibration levels are normal. Reduce vibration or improve pipe support (with damping material).
	Flexibles	Flexible connections	Potential failure	Flexible connections are easily damaged	If a flexible connection is necessary, it should be of an appropriate grade and on an inspection register.
	Emergency Shut off valve position.	Process line bellows outwith the emergency shut down valves.	Failure of bellows may be induced by machine vibration / pulsations. Release caused by failure would not be easily isolatable and incident could escalate.	Design standards for installation or modification to installation may not have covered possible hazard.	Improvement required to configuration. Mitigation of vibration protection does not protect from short term gross vibrations which can occur during run down of machine.
	Bearing temperatures	Bearing temperatures high (alarms in, check temperature instruments)	Bearing failure. Machine trip. Seal failure (as consequence). Process gas release.	Bearing or lubrication fault has not been identified by operators	Root cause analysis, appropriate remedial action

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Bearing temperatures	Burnt paint on bearing housings	Fire. Imminent machine failure.	Machines has been (if now cold) or is close to a major bearing failure. Temperature sensors faulty?	If hot - immediate unloading / controlled shutdown. If cold - avoid load changes, monitor closely while looking for cause.
Baseframe	Machine feet moving on bed (Cracked paint or "panting" - movement)	Misalignment. Possible major failure.	Holding down bolts loose or broken	Tighten bolts. Check freedom of sliding connections. Check for added constraints which should not be there
Oil spray	Sealant or oil spraying.	Bearing failure. Machine trip. Seal failure. Process gas release.	High pressure fluid being released through narrow crack which could enlarge	Monitor closely. Identify fluid and source. Remove source of pressure. Repair.
Temporary connections	Temporary flexible connections (small bore)	Loss of sealant system. Loss of lubrication. Loss of instrument connection.	Correct pipes have failed and been replaced with temporary ones.	Replace with correct hard pipe or suitable flexible.
Temporary connections	Temporary flexible connections (large bore)	Process gas release. Fire / explosion	Equipment being used in temporary berths / abnormal operating	Assess risk relating to fluids handled / duration of job / operator cover.
Essential Coupling maintenance	All couplings have clearly defined limits for miss alignment and Gear couplings require routine maintenance. Absence of information on alignment or routine maintenance will imply that these activities are not carried out.	Failed couplings can be thrown a long way.	Incorrect maintenance standards can lead to major failure of machine and loss of containment of substantial machine parts. Previous incidents show that shaft couplings are not contained by their cover guards.	Improvement needed to ensure appropriate maintenance applied.

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Maintenance	Seals	Drips of oil or sealant fluid	Seal or pipe joint damage - early indication of failure?	Problem could get worse and cause a failure	Identify source and monitor. Repair if appropriate.
	Open ends	Pipe open ends with no blanks	Hydrocarbon gas release if valve passes or is inadvertently operated.	Safety blank may have been left off through carelessness	Identify if the pipe should be blanked. Review instructions for relevant activity.
	Guarding	Guards loose / corroded	Personal injury.	Lack of care on routine inspections	Assess risk, plan repair or take more immediate action if appropriate
	Guarding	Guards missing	Personal injury	Poor working practices, lack of effective hand-over	Shut machine down or prevent access pending replacement.
	Thermal protection	Missing lagging or distance guarding	Personal Injury	Poor working practices, lack of effective hand-over	Danger needs to be highlighted and appropriate PPE available.
	Vibration levels	Rising trend of machine vibration levels, alarm points exceeded	High vibration levels on the machine may lead to damage of associated pipework due to resonances. Operating machine above alarm levels will place a higher demand rate on the ultimate protective devices.	Running machine at high vibration levels due to process fouling may be locally accepted as an operational need. Consequences of damage to associated equipment may not have been considered.	Improvement to operational / maintenance routines required.
	Danger of contact with oil	Oil leaks and standards for oil replenishment leaving oil spills	Oils and other fluids around machines will have their own specific hazard to personnel working with them	Poor working practices, lack of effective hand-over	Danger needs to be highlighted and appropriate PPE available.

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Operation	Machine Overspeed	Procedures for carrying out routine testing of protective devices.	Testing of the overspeed protection for machines introduces an additional level of risk, with conditions set where the machine can exceed its normal operational limits.	Overspeeding machines outside design limits has led to catastrophic failure of machinery and serious injuries to operational personnel.	Where no controls are in place, or are considered inadequate then prohibition must be considered as if too dangerous to test, continued running also has inherent dangers.
	Process temperature	Process temperatures outwith normal range	Overload. Compressor Trip. Pipe blockage (hydrate?)	Operators may not know potential consequence	Review operating instructions re temperatures.
	Noise	Noise level is unsteady	Control problems. Thrust balance problems.	A fault in the control system is causing load changes	Investigate root cause of noise fluctuation
	Instruments / displays	Machine and local instruments dirty	Poor operation. More likely to run out of operating limits.	Operators do not use (or trust ?) these instruments	Review operating instructions. Are local instruments required?
	Gas leak	Strong smell of hydrocarbon / sound of a leak.	Gas release. Explosion / fire.	Uncontrolled gas release	Immediate report to control room. Isolate remotely. Evacuate area at risk.
	Relief devices	Relief devices isolated	Over-pressure. Gas release. Explosion / fire.	Dangerous working practices, failure of PTW system	De-isolate or shut down. Investigate and correct failures in operating / maintenance philosophy
	Remote Isolation Protection	Bypass keys / software patches left in place and not covered by operating instructions	Protection may not respond to automatic shut down signals.	Event may escalate caused by delay in activating protection	Appropriate systems of control for protective device bypass required. All devices should be routinely tested for compliance and operation.

TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Disruption of upstream / down stream equipment	Operator reaction to alarm situations. No alarm situation should be allowed to persist without immediate action to restore system to operation within designed limits	Main dangers are normally prevented by automatic trip systems.	Operator action at the alarm point will reduce demand rate on ultimate protective system.	Appropriate systems of control for protective devices required. All devices should be routinely tested for compliance and operation.
Ingestion of Liquid	The process lines feeding compressors should have provision for separation and draining of liquid carried forward with the main flow or condensed from the process gas.	Compressors will be damaged by the ingestion of liquid. In severe cases this can lead to major machine damage and loss of process gas containment.	A hidden danger to compressors which are more vulnerable on re-commissioning when amounts of liquid may have accumulated.	Design improvement necessary.

7.4.4 GAS TURBINE OBSERVATIONS

- ***The table gives examples of Observations which would indicate Not Best Practice in the operation / maintenance of a Gas Turbine***

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Equipment	Vibration	Vibration monitors not functioning, or alarms in. Significant vibration can be felt	Machine damage, damage to fuel lines, fuel releases. Blade failures.	Operators not paying attention to vibration levels, not aware of potential damage	Review vibration monitoring policy / practice
	Fuel	High fuel pressures (if visible on local gauges)	Increased risk of pipe or joint failures (particularly flexible)	Fuel nozzle restrictions or excess fuel flow	Check fuel pressure vs. vendor data. Check operating logs.
Maintenance	Ventilation	Acoustic enclosure ventilation louvers very dirty or obscured	Over-heating, risk of flammable mixture. Gas detection ineffective	Effectiveness of ventilation is not checked	Carry out air flow test
	Ventilation	Enclosure doors left open. Panels removed	Wrong ventilation pattern, overheating, gas detection ineffective. Noise emissions	Operators are unaware of the potential hazard	Review operating / maintenance philosophy
	Oil leakage	Oil absorbent pads around enclosure base	Fuel or lubricant leakage? Pool fires? Fuel mist?	Operators unable to contain fuel or oil leak	Identify fluid and source. Plan remedial action.
	Oil Leakage	Oil absorbent pads around enclosure base	Slippery floor - personnel injury	Operators have not considered risk of injury	Identify fluid and source. Plan remedial action. Monitor condition of floor, warning signs / barriers

	TOPIC	KEY OBSERVATION	IMPACT	INFERENCE	ACTION
Operation	Acoustic enclosure	Viewing windows dirty / obscured / no internal lighting	Cannot see inside enclosure to check. Unnecessary entries. Increased personnel risk.	Checks, if made, require entry to enclosure	Review operating instructions - plan improvements
	Access	Enclosure access without permit	Increased personnel risk. Search problems if there is an incident.	Additional hazard of enclosure entry is not recognised	Review operating instructions & PTW control
	Personnel safety	Acoustic enclosure door can be padlocked	Potential to trap personnel inside	Trapping risk has not been recognised	Assess hazard, identify if alternative escape exists.
	Instruments	Control panel or local instrument displays inaccessible / dirty / damaged	Operators do not manage equipment, faults develop un-checked. Alarms might be missed.	Operators do not routinely check these instruments	Review operating instructions - are instruments necessary or redundant. Reinstate or remove.
	Exhaust	High discharge temperature (alarms in or scorched ducting)	Creep failure of blades. Missiles. Exhaust ducting / flexible failure.	Internal problems with turbine, fuel control problems	Review recent operating temperature and condition monitoring data

APPENDIX A – INDEX TO FIGURES AND GLOSSARY

Index to Figures

Index to Charts

GLOSSARY

Abbreviation	Description
AC	Alternating current
Aero-derivative	Gas turbine driver design derived from aero engine
Alarm	Warning to operator without interruption to operations
ATEX	Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations1996
Auditing	Process of independent checking of documentation / systems
BS EN 953	British Standard for Design of Guards
Cartridge	Mechanical sub-assembly, removed as a unit
COMAH	Control of Major Accident Hazards (Regulations)
COSHH	Control of Substances Hazardous to Health (Regulations)
dB(A)	Decibels "A" weighting - unit of noise exposure
DCS	Distributed Control System (Modern Computer Control)
Dry gas seal	Mechanical shaft seal using gas as the service fluid
E.L.D.	Engineering Line Diagram
FMEA	Failure Method Evaluation & Analysis
Fouling	Build-up of solid deposits inside a compressor or turbine
FPSO	Floating Production, Storage & Offloading (Installation)
HASAWA	Health and Safety at Work Act 1974
Induction	Safety Lecture / Training given on first visit to an installation
Inhibit	Automatic limitation to equipment operation
LOLER	Lifting Operations and Lifting Equipment Regulations 1998
MHSWR	Management of Health and Safety at Work Regulations 1992
MTBF	Mean Time Between Failures (Reliability Measure)
OIM	Offshore Installation Manager
Overspeed	Operation beyond defined safe limiting shaft speed
PLC	Programmable Logic Controller (small control computer)
PPE	Personal Protective Equipment
PTW	Permit to Work
Pusher seal	Mechanical seal using "O" ring dynamic sealing element
PUWER	Provision and Use of Work Equipment Regulations 1998
Seal	Device for controlling leakage path (usually on a shaft)
SHE	Safety, Health & Environment
Sour	Containing sulphur compounds (applies to gas or liquid)
Surge	Unstable operation of a dynamic compressor
Tannoy	Voice broadcast loudspeaker system
Temp.	Temperature (normally in degrees C)
Trip	Automatic stopping of equipment on fault condition
Turbo	Term for centrifugal design of compressor or expander

APPENDIX B – KEYWORD INDEX

Inspection Guidance Notes - Word Index
Keyword Sort Order

APPENDIX C – CONTENTS LIST (FULLY DETAILED)

APPENDIX D – SOURCE MATERIAL

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