LECTURE NOTES

ON

POWET PLANT CONTROL AND INSTRUMENTATION

B.Tech VI Sem (IARE-R16)

By

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UNIT-I
OVERVIEW OF POWER GENERATION

INTRODUCTION:

The utility electricity sector in India has one national grid with an installed capacity of 57.875 GW as of 30 June 2019. Renewable power plants, which also include large hydroelectric plants, constitute 34.86% of India's total installed capacity. During the 2017-18 fiscal year, the gross electricity generated by utilities in India was 1,303.49 TWh and the total electricity generation (utilities and non utilities) in the country was 1,486.5 TWh. The gross electricity consumption during the 2017-18 fiscal year was 1,149 kWh per capita. India is the world's third largest producer and third largest consumer of electricity. In the 2015-16 fiscal year, electric energy consumption in agriculture was recorded as being the highest (17.89%) worldwide.The per capita electricity consumption is low compared to most other countries despite India having a cheaper electricity tariff.

India has a surplus power generation capacity but lacks adequate infrastructure for supplying electricity to all who need it. In order to address the lack of adequate electricity supply to all the people in the country by March 2019, the Government of India launched a program called "Power for All".This program is intended to ensure continuous and uninterrupted electricity supply to all households, industries and commercial establishments by creating and improving the necessary infrastructure. It is a joint collaboration between the Government of India and its constituent states, who will share funding and create overall economic growth.

India's electricity sector is dominated by fossil fuels, and in particular, coal, which during the 2017-18 fiscal year produced about three-fourths of the country's electricity. However, the government is pushing for increased investment in renewable energy. The National Electricity Plan of 2018, prepared by the Government of India, states that the country does not need additional non-renewable power plants in the utility sector until 2027, with the commissioning of 50,025 MW coal-based power plants under construction and achieving 275,000 MW total installed renewable power capacity after the retirement of nearly 48,000 MW old coal-fired plants.

STEAM POWER PLANT:

A thermal power station is a power plant in which the prime mover is steam driven. Water is heated, turns into steam and spins a steam turbine which drives an electrical generator. After it passes through the turbine, the steam is condensed in a condenser and recycled to where it was heated; this is known as a Rankine cycle. The greatest variation in the design of thermal power stations is due to the different fuel sources. Some prefer to use the term *energy center* because such facilities convert forms of heat energy into electricity. Some thermal power plants also deliver heat energy for industrial purposes, for district heating, or for desalination of water as well as delivering electrical power. A large proportion of CO_2 is produced by the worlds fossil fired thermal power plants; efforts to reduce these outputs are various and widespread.

The four main circuits one would come across in any thermal power plant layout are

- Coal and Ash Circuit
- Air and Gas Circuit
- Feed Water and Steam Circuit
- Cooling Water Circuit

- **Coal and Ash Circuit:**

  Coal and Ash circuit in a thermal power plant layout mainly takes care of feeding the boiler with coal from the storage for combustion. The ash that is generated during combustion is collected at the back of the boiler and removed to the ash storage by scrap conveyors. The combustion in the Coal and Ash circuit is controlled by regulating the speed and the quality of coal entering the grate and the damper openings.

- **Air and Gas Circuit**
  Air from the atmosphere is directed into the furnace through the air preheated by the action of a forced draught fan or induced draught fan. The dust from the air is removed before it enters the combustion chamber of the thermal power plant layout. The exhaust gases from the combustion heat the air, which goes through a heat exchanger and is finally let off into the environment.

- **Feed Water and Steam Circuit**
  The steam produced in the boiler is supplied to the turbines to generate power. The steam that is expelled by the prime mover in the thermal power plant layout is then condensed in a condenser for re-use in the boiler. The condensed water is forced through a pump into the feed water heaters where it is heated using the steam from different points in the turbine. To make up for the lost steam and water while passing through the various components of the thermal power plant layout, feed water is supplied through external sources. Feed water is purified in a purifying plant to reduce the dissolve salts that could scale the boiler tubes.

- **Cooling Water Circuit:** The quantity of cooling water required to cool the steam in a thermal power plant layout is significantly high and hence it is supplied from a natural water source like a lake or a river. After passing through screens that remove particles that can plug the condenser tubes in a thermal power plant layout, it is passed through the condenser where the steam is condensed. The water is finally discharged back into the water source after cooling. Cooling water circuit can also be a closed system where the cooled water is sent through cooling towers for re-use in the power plant. The cooling water circulation in the condenser of a thermal power plant layout helps in maintaining a low pressure in the condenser all throughout.

All these circuits are integrated to form a thermal power plant layout that generates electricity to meet our needs.

HYDEL POWER PLANT

Hydroelectric power plants convert the hydraulic potential energy from water into electrical energy. Such plants are suitable were water with suitable *head* are available. The layout covered in this article is just a simple one and only cover the important parts of hydroelectric plant. The different parts of a hydroelectric power plant are

(1) **Dam:** Dams are structures built over rivers to stop the water flow and form a reservoir.The reservoir stores the water flowing down the river. This water is diverted to turbines in power stations. The dams collect water during the rainy season and stores it, thus allowing for a steady flow through the turbines throughout the year. Dams are also used for controlling floods and irrigation. The dams should be water-tight and should be able to withstand the pressure exerted by the water on it. There are different types of dams such as arch dams, gravity dams and buttress dams. The height of water in the dam is called *head race*.

(2) Spillway: A spillway as the name suggests could be called as a way for spilling of water from dams. It is used to provide for the release of flood water from a dam. It is used to prevent over toping of the dams which could result in damage or failure of dams. Spillways could be controlled type or uncontrolled type. The uncontrolled types start releasing water upon water rising above a particular level. But in case of the controlled type, regulation of flow is possible.

(3) Penstock and Tunnel: Penstocks are pipes which carry water from the reservoir to the turbines inside power station. They are usually made of steel and are equipped with gate systems. Water under high pressure flows through the penstock. A tunnel serves the same purpose as a penstock. It is used when an obstruction is present between the dam and power station such as a mountain.

(4) Surge Tank: Surge tanks are tanks connected to the water conductor system. It serves the purpose of reducing water hammering in pipes which can cause damage to pipes. The sudden surges of water in penstock are taken by the surge tank, and when the water requirements increase, it supplies the collected water thereby regulating water flow and pressure inside the penstock.

(5) Power Station: Power station contains a turbine coupled to a generator. The water brought to the power station rotates the vanes of the turbine producing torque and rotation of turbine shaft. This rotational torque is transferred to the generator and is converted into electricity. The used water is released through the *tail race*. The difference between head race and tail race is called gross head and by subtracting the frictional losses we get the net head available to the turbine for generation of electricity.

NUCLEAR POWER PLANT:

Nuclear power is the use of sustained Nuclear fission to generate heat and douseful work. Nuclear Electric Plants, Nuclear Ships and Submarines use controlled nuclear energy to heat water and produce steam, while in space, nuclear energy decays naturally in a radioisotope thermoelectric generator. Scientists are experimenting with fusion energy for future generation, but these experiments do not currently generate useful energy. Nuclear power provides about 6% of the world's energy and 13–14% of the world's electricity, with the U.S., France, and Japan together accounting for about 50% of nuclear generated electricity. Also, more than 150 naval vessels using nuclear propulsion have been built.

Just as many conventional thermal power stations generate electricity by harnessing the thermal energy released from burning fossil fuels, nuclear power plants convert the energy released from the nucleus of an atom, typically via nuclear fission.

Nuclear reactor technology

When a relatively large fissile atomic nucleus (usually uranium-235 or plutonium-239) absorbs a neutron, a fission of the atom often results. Fission splits the atom into two or more smaller nuclei with kinetic energy (known as fission products) and also releases gamma radiation and free neutrons.[59] A portion of these neutrons may later be absorbed by other fissile atoms and create more fissions, which release more neutrons, and so on.This nuclear chain reaction can be controlled by using neutron poisons and neutron moderators to change the portion of neutrons that will go on to cause more fissions.[60] Nuclear reactors generally have automatic and manual systems to shut the fission reaction down if unsafe conditions are detected. Three nuclear powered ships, (top to bottom) nuclear cruisers USS Bainbridge and USS Long Beach with *USS Enterprise* the first nuclear powered aircraft carrier in 1964. Crew members are spelling out Einstein's mass-energy equivalence formula $E = mc^2$ on the flight deck.

There are many different reactor designs, utilizing different fuels and coolants and incorporating different control schemes. Some of these designs have been engineered to meet a specific need. Reactors for nuclear submarines and large naval ships, for example, commonly use highly enriched uranium as a fuel. This fuel choice increases the reactor's power density and extends the usable life of the nuclear fuel load, but is more expensive and a greater risk to nuclear proliferation than some of the other nuclear fuels.

A number of new designs for nuclear power generation, collectively known as the Generation IV reactors, are the subject of active research and may be used for practical power generation in the future. Many of these new designs specifically attempt to make fission reactors cleaner, safer and/or less of a risk to the proliferation of nuclear weapons. Passively safe plants (such as the ESBWR) are available to be built and other designs that are believed to be nearly fool-proof are being pursued. Fusion reactors, which may be viable in the future, diminish or eliminate many of the risks associated with nuclear fission. There are trades to be made between safety, economic and technical properties of different reactor designs for particular applications. Historically these decisions were often made in private by scientists, regulators and engineers, but this may be considered problematic, and since Chernobyl and Three Mile Island, many involved now consider informed consent and morality should be primary considerations.

Cooling system

A cooling system removes heat from the reactor core and transports it to another area of the plant, where the thermal energy can be harnessed to produce electricity or to do other useful work. Typically the hot coolant will be used as a heat source for a boiler, and the pressurized steam from that boiler will power one or more steam turbine driven electrical generators.

Flexibility of nuclear power plants

It is often claimed that nuclear stations are inflexible in their output, implying that other forms of energy would be required to meet peak demand. While that is true for the vast majority of reactors, this is no longer true of at least some modern designs. Nuclear plants are routinely used in load following mode on a large scale in France. Unit A at the German Biblis Nuclear Power Plant is designed to in- and decrease his output 15 % per minute between 40 and 100 % of it's nominal power. Boiling water reactors normally have load-following capability, implemented by varying the recirculation water flow.

SOLAR POWER PLANT

Solar power plants use the sun's rays to produce electricity. Photovoltaic plants and solar thermal systems are the most commonly used solar technologies today.

1. **Photovoltaic plants: A** photovoltaic cell, commonly called a solar cell or PV, is a technology used to convert solar energy directly into electricity. A photovoltaic cell is usually made from silicon alloys. Particles of solar energy, known as photons, strike the surface of a photovoltaic cell between two semiconductors. These semiconductors exhibit a property known as the photoelectric effect, which causes them to absorb the photons and release electrons. The electrons are captured in the form of an electric current - in other words, electricity.

2. **Solar thermal power plants :**A solar thermal plant generates heat and electricity by concentrating the sun's energy. That in turn builds steam that helps to feed a turbine and generator to produce electricity.

There are three types of solar thermal power plants:

a) **Parabolic troughs:** This is the most common type of solar thermal plant. A "solar field" usually contains many parallel rows of solar parabolic trough collectors. They use parabola-shaped reflectors to focus the sun at 30 to 100 times its normal intensity. The method is used to heat a special type of fluid, which is then collected at a central location to generate high-pressure, superheated steam.

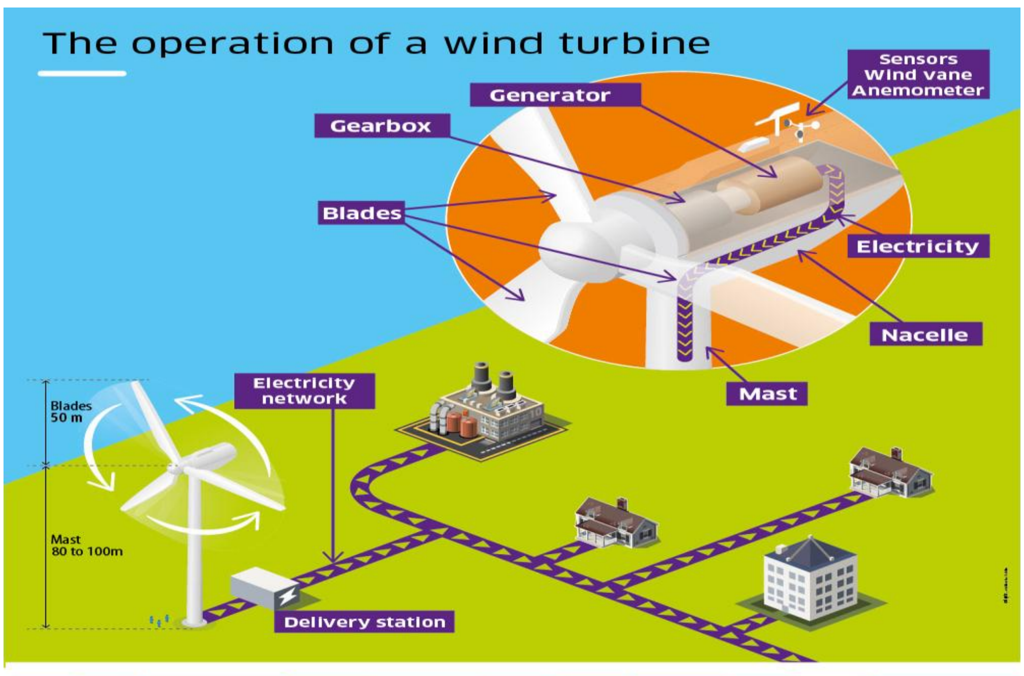
b) **Solar power tower :**This system uses hundreds to thousands of flat sun-tracking mirrors called heliostats to reflect and concentrate the sun's energy onto a central receiver tower. The energy can be concentrated as much as 1,500 times that of the energy coming in from the sun.
A test solar power tower exists in Juelich in the western German state of North-Rhine Westphalia. It is spread over 18,000 square meters (194,000 square feet) and uses more than 2,000 sun-tracking mirrors to reflect and concentrate the sun's energy onto a 60-meter-high (200 foot high) central receiver tower.
The concentrated solar energy is used to heat the air in the tower to up to 700 degrees Celsius (1,300 degrees Fahrenheit). The heat is captured in a boiler and is used to produce electricity with the help of a steam turbine. Solar thermal energy collectors work well even in adverse weather conditions. They're used in the Mojave Desert in California and have withstood hailstorms and sandstorms.

c) **Solar pond:**This is a pool of saltwater which collects and stores solar thermal energy. It uses so-called salinity-gradient technology.
Basically, the bottom layer of the pond is extremely hot - up to 85 degrees Celsius - and acts as a transparent insulator, permitting sunlight to be trapped from which heat may be withdrawn or stored for later use. This technology has been used in Israel since 1984 to produce electricity.

When the wind, a natural form of energy, is capable of creating electricity or a mechanical force, this is wind power.

Rather like windmills (a name they are sometimes given), wind turbines use the power of the wind, which they transform into electricity. The speed of the wind rotates the blades of a rotor (between 10 and 25 rpm), producing kinetic energy. The rotor then drives a generator that converts the mechanical energy into electricity. A weathervane and a robot orient the nacelle so that the blades are positioned optimally with regard to the wind. Each wind turbine is made up of a mast, which can be between 20 and 100 meters tall, depending on the power of the machine, which supports the rotor, generally consisting of three blades, and the nacelle, which houses the generator and the electrical and mechanical gear. The wind turbines are connected to the power grid via a transformer housed at the base of the mast. The electricity generated is generally raised to the grid voltage (20 kV). It is then transferred via a substation before being injected into the distribution or transmission networks.

The power of modern onshore wind turbines is in excess of 3 MW. Wind turbines are designed for wind speeds of between 14 and 90 kph. When the wind speed is faster, a braking mechanism automatically stops the wind turbine, ensuring the safety of the installation and minimizing wear. Modern wind turbines produce their rated output at wind speeds of around 50 kph.



The majority of wind turbines consist of three blades mounted to a tower made from tubular steel. There are less common varieties with two blades, or with concrete or steel lattice towers. At 100 feet or more above the ground, the tower allows the turbine to take advantage of faster wind speeds found at higher altitudes.

Turbines catch the wind's energy with their propeller-like blades, which act much like an airplane wing. When the wind blows, a pocket of low-pressure air forms on one side of the blade. The low-pressure air pocket then pulls the blade toward it, causing the rotor to turn. This is called lift. The force of the lift is much stronger than the wind's force against the front side of the blade, which is called drag. The combination of lift and drag causes the rotor to spin like a propeller.

A series of gears increase the rotation of the rotor from about 18 revolutions a minute to roughly 1,800 revolutions per minute -- a speed that allows the turbine’s generator to produce AC electricity.

A streamlined enclosure called a nacelle houses key turbine components -- usually including the gears, rotor and generator -- are found within a housing called the nacelle. Sitting atop the turbine tower, some nacelles are large enough for a helicopter to land on.

Another key component is the turbine’s controller, that keeps the rotor speeds from exceeding 55 mph to avoid damage by high winds. An anemometer continuously measures wind speed and transmits the data to the controller. A brake, also housed in the nacelle, stops the rotor mechanically, electrically or hydraulically in emergencies. Explore the interactive graphic above to learn more about the mechanics of wind turbines.

Types of Wind Turbines: There are two basic types of wind turbines: those with a horizontal axis, and those with aa vertical axis.

The majority of wind turbines have a horizontal axis: a propeller-style design with blades that rotate around a horizontal axis. Horizontal axis turbines are either upwind (the wind hits the blades before the tower) or downwind (the wind hits the tower before the blades). Upwind turbines also include a yaw drive and motor -- components that turns the nacelle to keep the rotor facing the wind when its direction changes.

While there are several manufacturers of vertical axis wind turbines, they have not penetrated the utility scale market (100 kW capacity and larger) to the same degree as horizontal access turbines. Vertical axis turbines fall into two main designs:

- Drag-based, or Savonius, turbines generally have rotors with solid vanes that rotate about a vertical axis.
- Lift-based, or Darrieus, turbines have a tall, vertical airfoil style (some appear to have an eggbeater shape). The Windspire is a type of lift-based turbine that is undergoing independent testing at the National Renewable Energy Laboratory'sNational Wind Technology Center.

Wind Turbine Applications: Wind Turbines are used in a variety of applications – from harnessing offshore wind resources to generating electricity for a single home:

- Large wind turbines, most often used by utilities to provide power to a grid, range from 100 kilowatts to several megawatts. These utility-scale turbines are often grouped together in wind farms to produce large amounts of electricity. Wind farms can consist of a few or hundreds of turbines, providing enough power for tens of thousands of homes.
- Small wind turbines, up to 100 kilowatts, are typically close to where the generated electricity will be used, for example, near homes, telecommunications dishes or water pumping stations. Small turbines are sometimes connected to diesel generators, batteries and photovoltaic systems. These systems are called hybrid wind systems and are typically used in remote, off-grid locations, where a connection to the utility grid is not available.

- Offshore wind turbines are used in many countries to harness the energy of strong, consistent winds found off of coastlines. The technical resource potential of the winds above U.S. coastal waters is enough to provide more than 4,000 gigawatts of electricity, or approximately four times the generating capacity of the current U.S. electric power system. Although not all of these resources will be developed, this represents a major opportunity to provide power to highly populated coastal cities. To take advantage of America's vast offshore wind resources, the Department is investing in three offshore wind demonstration projects designed to deploy offshore wind systems in federal and state waters by 2017.

Importance of instrumentation in power generation:

The role of instrumentation in thermal power plants is like any other process plants. There are various parameters like pressure, temperature, flow, level, vibration etc which needs to be monitored and controlled in such plants. Also some modern plants have automation systems like DCS and PLC along with many interlocks. So instrumentation have an critical role in thermal power plants. Steam is mainly required for power generation, process heating and pace heating purposes. The capacity of the boilers used for power generation is considerably large compared with other boilers. Due to the requirement of high efficiency, the steam for power generation is produced at high pressures and in very large quantities. They are very large in size and are of individual design depending the type of fuel to be used.

The boilers generating steam for process heating are generally smaller in size and generate steam at a much lower pressure. They are simpler in design and are repeatedly constructed to the same design. Though most of these boilers are used for heating purposes, some, like locomotive boilers are used for power generation also. In this chapter, some simple types of boilers will be described. A steam generator popularly known as boiler is a closed vessel made of high quality steel in which steam is generated from water by the application of heat. The water receives heat from the hot gases though the heating surfaces of the boiler. The hot gases are formed by burning fuel, may be coal, oil or gas. Heating surface of the boiler is that part of the boiler which is exposed to hot gases on one side and water or steam on the other side. The steam which is collected over the water surface is taken from the boiler through super heater and then suitable pipes for driving engines or turbines or for some industrial heating purpose. A boiler consists of not only the steam generator but also a number of parts to help for the safe and efficient operation of the system as a whole. These parts are called mountings and accessories.

BOILER :

A **boiler** is a closed vessel in which water or other fluid is heated. The heated or vaporized fluid exits the boiler for use in various processes or heating applications.Most boilers produce steam to be used at saturation temperature; that is, saturated steam. Superheated steam boilers vaporize the water and then further heat the steam in a *superheater*. This provides steam at much higher temperature, but can decrease the overall thermal efficiency of the steam generating plant because the higher steam temperature requires a higher flue gas exhaust temperature. There are several ways to circumvent this problem, typically by providing an *economizer* that heats the feed water, a combustion air heater in the hot flue gas exhaust path, or both. There are advantages to superheated steam that may, and often will, increase overall efficiency of both steam generation and its utilization: gains in input temperature to a turbine should outweigh any cost in additional boiler complication and expense. There may also be practical limitations in using *wet* steam, as entrained condensation droplets will damage turbine blades.Superheated steam presents unique safety concerns because, if any system component fails and allows steam to escape, the high pressure and temperature can cause serious, instantaneous harm to anyone in its path. Since the escaping steam will initially be completely superheated vapor, detection can be difficult, although the intense heat and sound from such a leak clearly indicates its presence.

Superheater operation is similar to that of the coils on an air conditioning unit, although for a different purpose. The steam piping is directed through the flue gas path in the boiler furnace. The temperature in this area is typically between 1,300–1,600 degrees Celsius. Some superheaters are radiant type; that is, they absorb heat by radiation. Others are convection type, absorbing heat from a fluid. Some are a combination of the two types. Through either method, the extreme heat in the flue gas path will also heat the superheater steam piping and the steam within. While the temperature of the steam in the superheater rises, the pressure of the steam does not: the turbine or moving pistons offer a *continuously expanding space* and the pressure remains the same as that of the boiler.Almost all steam superheater system designs remove droplets entrained in the steam to prevent damage to the turbine blading and associated piping.

SUPERCRITICAL BOILER:

Supercritical steam generators (also known as Benson boilers) are frequently used for the production of electric power. They operate at "supercritical pressure". In contrast to a "subcritical boiler", a supercritical steam generator operates at such a high pressure (over 3,200 psi/22.06 MPa or 220.6 bar) that actual boiling ceases to occur, and the boiler has no water - steam separation. There is no generation of steam bubbles within the water, because the pressure is above the "critical pressure" at which steam bubbles can form. It passes below the critical point as it does work in the high pressure turbine and enters the generator's condenser. This is more efficient, resulting in slightly less fuel use. The term "boiler" should not be used for a supercritical pressure steam generator, as no "boiling" actually occurs in this device.

FLUIDIZED BED BOILERS:

The major portion of the coal available in India is of low quality, high ash content and low calorific value. The traditional grate fuel firing systems have got limitations and are techno-economically unviable to meet the challenges of future. Fluidized bed combustion has emerged as a viable alternative and has significant advantages over conventional firing system and offers multiple benefits – compact boiler design, fuel flexibility, higher combustion efficiency and reduced emission of noxious pollutants such as SOx and NOx. The fuels burnt in these boilers include coal, washery rejects, rice husk, bagasse & other agricultural wastes. The fluidized bed boilers have a wide capacity range- 0.5 T/hr to over 100 T/hr.

Piping and instrumentation diagram:

A piping and instrumentation diagram (P&ID) is a detailed diagram in the process industry which shows the piping and process equipment together with the instrumentation and control devices.

A piping and instrumentation diagram (P&ID) is defined by the Institute of Instrumentation and Control as follows:

1. A diagram which shows the interconnection of process equipment and the instrumentation used to control the process. In the process industry, a standard set of symbols is used to prepare drawings of processes. The instrument symbols used in these drawings are generally based on International Society of Automation (ISA) Standard S5.1
2. The primary schematic drawing used for laying out a process control installation.

They usually contain the following information:

- Mechanical equipment, including:
  - Pressure vessels, columns, tanks, pumps, compressors, heat exchangers, furnaces, wellheads, fans, cooling towers, turbo-expanders, pig traps (see 'symbols' below)
  - Bursting discs, restriction orifices, strainers and filters, steam traps, moisture traps, sight-glasses, silencers, flares and vents, flame arrestors, vortex breakers, eductors
- Process piping, sizes and identification, including:
  - Pipe classes and piping line numbers
  - Flow directions
  - Interconnections references
  - Permanent start-up, flush and bypass lines
  - Pipelines and flowlines
  - Blinds and spectacle blinds
  - Insulation and heat tracing
- Process control instrumentation and designation (names, numbers, unique tag identifiers), including:

- Valves and their types and identifications (e.g. isolation, shutoff, relief and safety valves, valve interlocks)
- Control inputs and outputs (sensors and final elements, interlocks)
- Miscellaneous - vents, drains, flanges, special fittings, sampling lines, reducers and swages

- Interfaces for class changes
- Computer control system
- Identification of components and subsystems delivered by others

P&IDs are originally drawn up at the design stage from a combination of process flow sheet data, the mechanical process equipment design, and the instrumentation engineering design. During the design stage, the diagram also provides the basis for the development of system control schemes, allowing for further safety and operational investigations, such as a Hazard and operability study (HAZOP). To do this, it is critical to demonstrate the physical sequence of equipment and systems, as well as how these systems connect.

P&IDs also play a significant role in the maintenance and modification of the process after initial build. Modifications are red-penned onto the diagrams and are vital records of the current plant design.

They are also vital in enabling development of;

Control and shutdown schemes

Safety and regulatory requirements

Start-up sequences

Operational understanding.

P&IDs form the basis for the live mimic diagrams displayed on graphical user interfaces of large industrial control systems such as SCADA and distributed control systems.

Based on STANDARD ANSI/ISA S5.1 and ISO 14617-6, the P&ID is used for the identification of measurements within the process. The identifications consist of up to 5 letters. The first identification letter is for the measured value, the second is a modifier, 3rd indicates passive/readout function, 4th - active/output function, and the 5th is the function modifier. This is followed by loop number, which is unique to that loop. For instance FIC045 means it is the Flow Indicating Controller in control loop 045. This is also known as the "tag" identifier of the field device, which is normally given to the location and function of the instrument. The same loop may have FT045 - which is the flow transmitter in the same loop.

Letter	Column 1 (Measured value)	Column 2 (Modifier)	Column 3 (Readout/passive function)	Column 4 (Output/active function)	Column 5 (Function modifier)
A	Analysis		Alarm		
B	Burner,		User choice	User choice	User choice

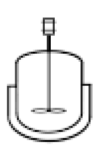
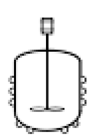
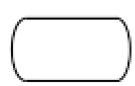
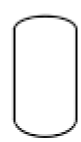
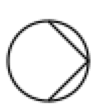
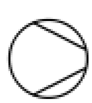
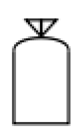
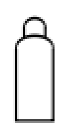
	combustion				
C	User's choice (usually conductivity)			Control	Close
D	User's choice (usually density)	Difference			Deviation
E	Voltage		Sensor		
F	Flow rate	Ratio			
G	User's choice (usually gaging/gauging)	Gas	Glass/gauge/viewing		
H	Hand				High
I	Current		Indicate		
J	Power	Scan			
K	Time, time schedule	Time rate of change		Control station	
L	Level		Light		Low
M	User's choice				Middle / intermediate
N	User's choice (usually torque)		User choice	User choice	User choice
O	User's choice		Orifice		Open
P	Pressure		Point/test connection		
Q	Quantity	Totalize/integrate	Totalize/integrate		
R	Radiation		Record		Run
S	Speed, frequency	Safety (Non SIS (S5.1))		Switch	Stop
T	Temperature			Transmit	
U	Multivariable		Multifunction	Multifunction	
V	Vibration,			Valve or	

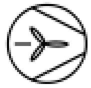
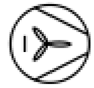
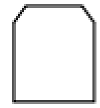
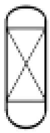
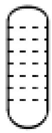
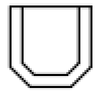
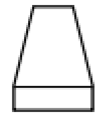
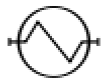
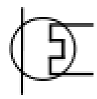
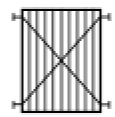
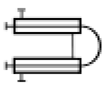
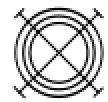
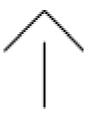
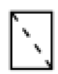
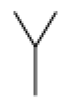
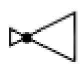
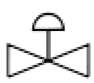
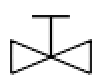
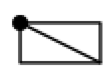
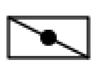
	mechanical analysis			damper	
W	Weight, force		Well or probe		
X	User's choice (usually on-off valve as XV)	X-axis	Accessory devices, unclassified	Unclassified	Unclassified
Y	Event, state, presence	Y-axis		Auxiliary devices	
Z	Position, dimension	Z-axis or Safety Instrumented System		Actuator, driver or unclassified final control element	

For reference designation of any equipment in industrial systems the standard IEC 61346 (Industrial systems, installations and equipment and industrial products — Structuring principles and reference designations) can be applied. For the function Measurement the reference designator B is used, followed by the above listed letter for the measured variable.

Symbols of chemical apparatus and equipment

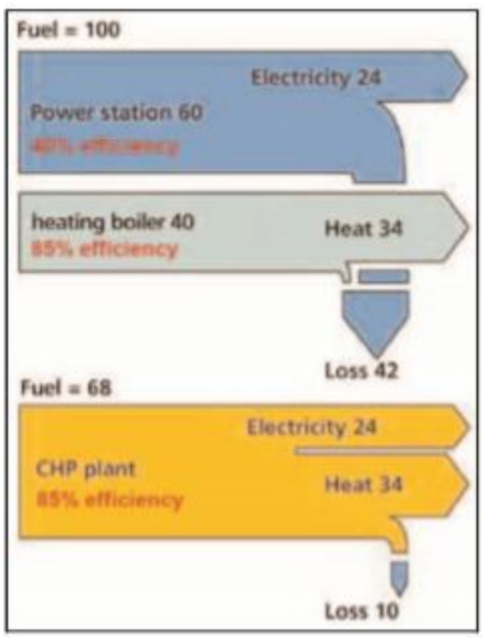
Below are listed some symbols of chemical apparatus and equipment normally used in a P&ID, according to ISO 10628 and ISO 14617.

Symbols of chemical apparatus and equipment							
	Pipe		Thermally insulated pipe		Jacketed pipe		Cooled or heated pipe
	Jacketed mixing vessel (autoclave)		Half pipe mixing vessel		Pressurized horizontal vessel		Pressurized vertical vessel
	Pump		Vacuum pump or compressor		Bag		Gas bottle

	Fan		Axial fan, MK, ,		Radial fan		Dryer
	Packed column		Tray column		Furnace		Cooling tower
	Heat exchanger		Heat exchanger		Cooler		Plate & frame heat exchanger
	Double pipe heat exchanger		Fixed straight tubes heat exchanger		U shaped tubes heat exchanger		Spiral heat exchanger
	Covered gas vent		Curved gas vent		(Air) filter		Funnel or tundish
	Steam trap		Viewing glass		Pressure reducing valve		Flexible pipe
	Valve		Control valve		Manual valve		Check valve
	Needle valve		Butterfly valve		Diaphragm valve		Ball valve

Need for Cogeneration: Thermal power plants are a major source of electricity supply in India. The conventional method of power generation and supply to the customer is wasteful in the sense that only about a third of the primary energy fed into the power plant is actually made available to the user in the form of electricity (Figure 7.1). In conventional power plant, efficiency is only 35% and remaining 65% of energy is lost. The major source of loss in the conversion process is the heat rejected to the surrounding water or air due to the inherent constraints of the different thermodynamic cycles employed in power generation. Also further losses of around 10–15% are associated with the transmission and distribution of electricity in the electrical grid.

Principle of Cogeneration: Cogeneration or Combined Heat and Power (CHP) is defined as the sequential generation of two different forms of useful energy from a single primary energy source, typically mechanical energy and thermal energy. Mechanical energy may be used either to drive an alternator for producing electricity, or rotating equipment such as motor, compressor, pump or fan for delivering various services. Thermal energy can be used either for direct process applications or for indirectly producing steam, hot water, hot air for dryer or chilled water for process cooling. Cogeneration provides a wide range of technologies for application in various domains of economic activities. The overall efficiency of energy use in cogeneration mode can be up to 85 per cent and above in some cases.

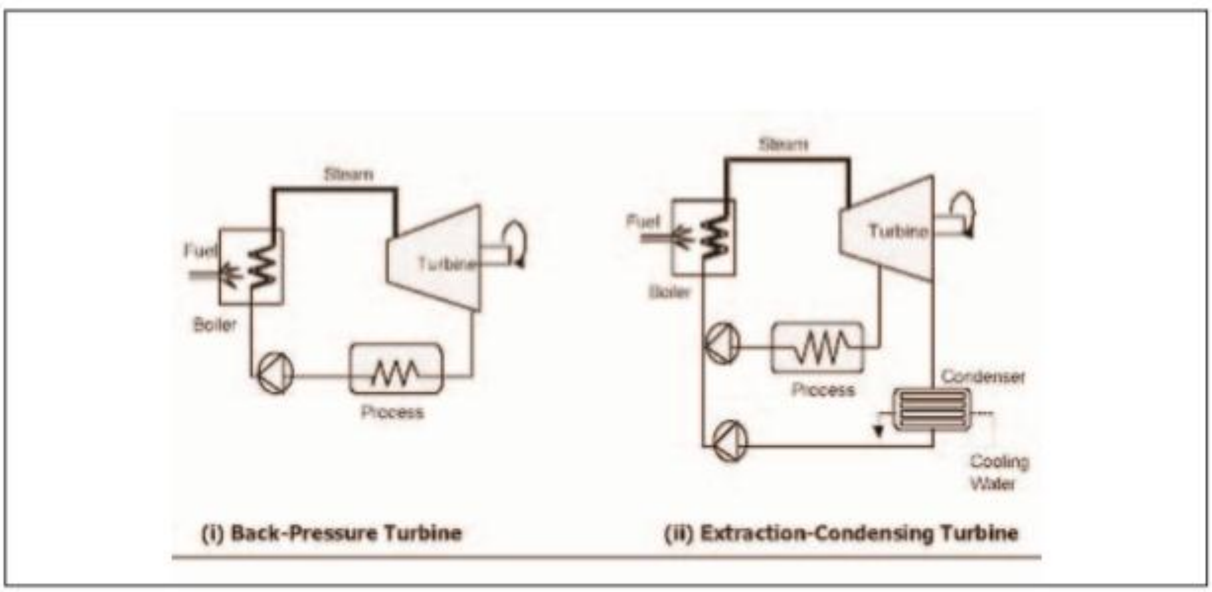


For example in the scheme shown in Figure, an industry requires 24 units of electrical energy and 34 units of heat energy. Through separate heat and power route the primary energy input in power plant will be 60 units (24/0.40). If a separate boiler is used for steam generation then the fuel input to boiler will be 40 units (34/0.85). If the plant had cogeneration then the fuel input will be only 68 units (24+34)/0.85 to meet both electrical and thermal energy requirements.

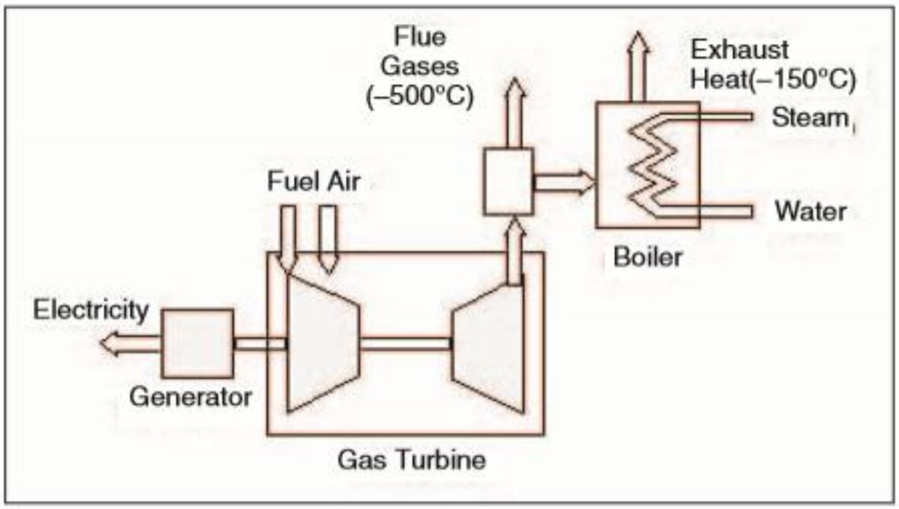
It can be observed that the losses, which were 42 units in the case of, separate heat and power has reduced to 10 units in cogeneration mode. Along with the saving of fossil fuels, cogeneration also allows to reduce the emission of greenhouse gases (particularly CO2 emission). The production of electricity being on-site, the burden on the utility network is reduced and the transmission line losses eliminated. Cogeneration makes sense from both macro and micro perspectives. At the macro level, it allows a part of the financial burden of the national power utility to be shared by the private sector; in addition, indigenous energy sources are conserved. At the micro level, the overall energy bill of the users can be reduced, particularly when there is a simultaneous need for both power and heat at the site, and a rational energy tariff is practiced in the country.

Technical Options for Cogeneration: Cogeneration technologies that have been widely commercialized include extraction/back pressure steam turbines, gas turbine with heat recovery boiler (with or without bottoming steam turbine) and reciprocating engines with heat recovery boiler.

Steam Turbine Cogeneration systems: The two types of steam turbines most widely used are the backpressure and the extraction.Another variation of the steam turbine topping cycle cogeneration system is the extraction-back pressure turbine that can be employed where the end-user needs thermal energy at two different temperature levels. The full-condensing steam turbines are usually incorporated at sites where heat rejected from the process is used to generate power. The specific advantage of using steam turbines in comparison with the other prime movers is the option for using a wide variety of conventional as well as alternative fuels such as coal, natural gas, fuel oil and biomass. The power generation efficiency of the demand for electricity is greater than one MW up to a few hundreds of MW. Due to the system inertia, their operation is not suitable for sites with intermittent energy demand.

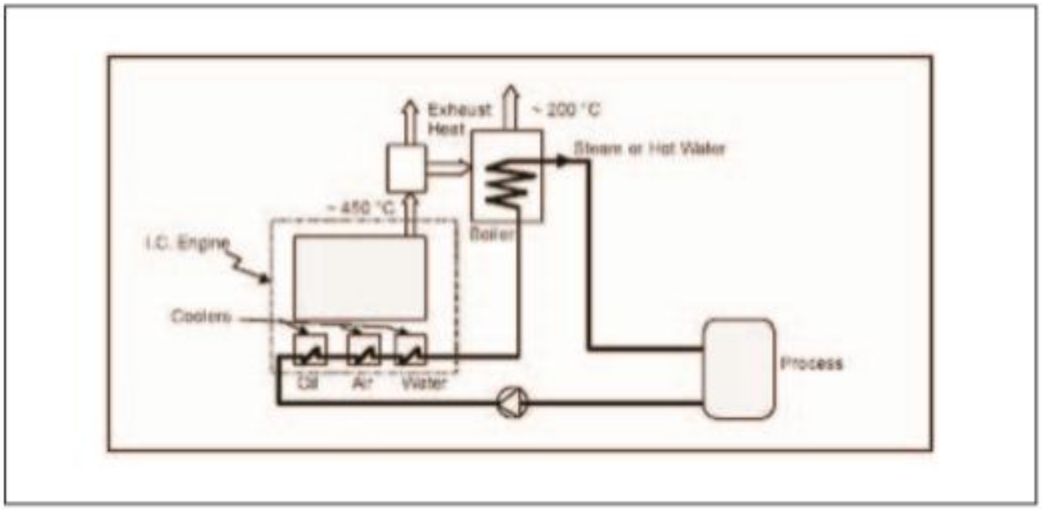


Gasturbine Cogeneration Systems: Gas turbine cogeneration systems can produce all or a part of the energy requirement of the site, and the energy released at high temperature in the exhaust stack can be recovered for various heating and cooling applications (see Figure 7.4). Though natural gas is most commonly used, other fuels such as light fuel oil or diesel can also be employed. The typical range of gas turbines varies from a fraction of a MW to around 100 MW. Gas turbine cogeneration has probably experienced the most rapid development in the recent years due to the greater availability of natural gas, rapid progress in the technology, significant reduction in installation costs, and better environmental performance. Furthermore, the gestation period for developing a project is shorter and the equipment can be delivered in a modular manner. Gas turbine has a short start-up time and provides the flexibility of intermittent operation. Though it has a low heat to power conversion efficiency, more heat can be recovered at higher temperatures. If the heat output is less than that required by the user, it is possible to have supplementary natural gas firing by mixing additional fuel to the oxygen-rich exhaust gas to boost the thermal output more efficiently.



On the other hand, if more power is required at the site, it is possible to adopt a combined cycle that is a combination of gas turbine and steam turbine cogeneration. Steam generated from the exhaust gas of the gas turbine is passed through a backpressure or extraction-condensing steam turbine to generate additional power. The exhaust or the extracted steam from the steam turbine provides the required thermal energy.

Reciprocating Engine Cogeneration Systems: Also known as internal combustion (I. C.) engines, these cogeneration systems have high power generation efficiencies in comparison with other prime movers. There are two sources of heat for recovery: exhaust gas at high temperature and engine jacket cooling water system at low temperature (see Figure 7.5). As heat recovery can be quite efficient for smaller systems, these systems are more popular with smaller energy consuming facilities, particularly those having a greater need for electricity than thermal energy and where the quality of heat required is not high, e.g. low pressure steam or hot water.

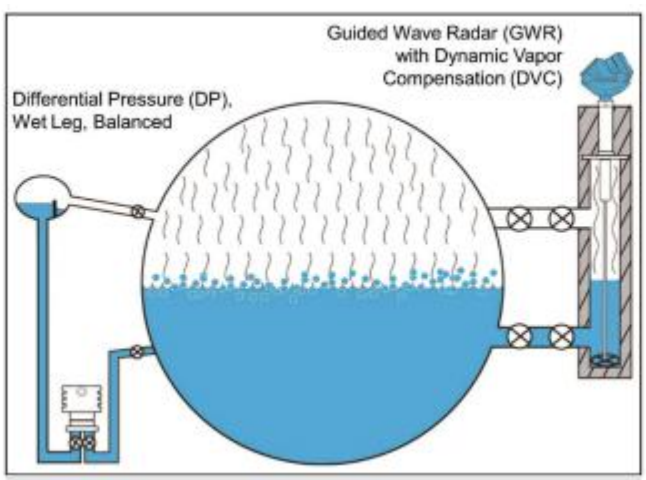


Though diesel has been the most common fuel in the past, the prime movers can also operate with heavy fuel oil or natural gas. These machines are ideal for intermittent operation and their performance is not as sensitive to the changes in ambient temperatures as the gas turbines. Though the initial investment on these machines is low, their operating and maintenance costs are high due to high wear and tear.

UNIT –II
MEASUREMENTS IN POWER PLANTS

Drum level measurement:

Drum level is critical for safety and reliability. Inaccurate drum level control can result in safety issues and equipment damage. High levels can cause water carryover that lowers heat transfer efficiency and possibly damages downstream equipment such as steam turbines. Low levels expose tubes to excessive heat, resulting in tube damage and unplanned shutdown. Drum level measurement is not as simple as it might appear. Typical challenges include the need for high-pressure and high-temperature equipment, the fact that density and dielectric (DC) of water and steam vary as pressure and temperature change, and that the control ranges across a small span. Another issue is the shrink and swell phenomenon. As steam demand decreases, drum pressure increases, which compresses entrained steam bubbles and can cause the drum level to appear to decrease even though it actually increases. Conversely, as steam demand increases, drum pressure decreases, and the gas bubbles expand, often causing the drum level to appear to increase. To help compensate for shrink and swell, boiler control engineers employ three-element control strategies that simultaneously look at steam flow, the rate feed water is flowing to the steam drum and the water level in the steam drum. In addition, compensation for pressure and temperature must be made either at the level instrument or in the computer control system. Redundant drum level measurements are recommended for safety and reliability, and because a steam drum can be uneven because of irregular heating over time, redundantly measuring on the front and back is often preferred. Another best practice is to use different measurement technologies for measurement redundancy. Figure depicts one way to obtain measurement redundancy by combining differential pressure (DP) and guided wave radar (GWR) level technologies.



Drum level measurement redundancy is best achieved by using different instruments such as both DP and GWR.

GWR can be especially advantageous in obtaining a reliable drum measurement for cases in which the level is continuously swinging. The separate measurement chamber used with GWR can dampen the effects of load swings and shrink/swell to a degree. GWR measures the time of flight of an electromagnetic pulse. It is independent of density, but steam DC can cause up to 20 percent error and varies with pressure changes. For this reason, compensation must be made for DC when using this level technology. Compensation can be accomplished in the computer controls, but obtaining a DC value for what the GWR sees is often difficult. A more direct approach is to work with a GWR device that carries out this compensation internally. Called Dynamic Vapor Compensation (DVC), it works by inserting a fixed reflective object in the path of the radar waves, well above any expected liquid level (see Figure 4). The GWR compares the measured distance to the reflector with its known distance to create a compensation value that it applies to all readings. Because it determines this correction value continuously, it corrects measurement errors under all conditions and reduces the error rate to less than 2 percent.

Oxygen measurement: The flue gas oxygen measurement at the back end of a boiler is arguably the most critical parameter used by the combustion control strategy. Managing oxygen concentration in boiler exhaust gases is important for maintaining safety and thermal efficiency. If oxygen content is too low, the combustion process will generate excess emissions or a potentially hazardous combustible mixture that is a risk for explosion. High excess oxygen results in heat loss and possibly additional carryover that can foul tubes in the generating sections of the boiler. To support an optimal combustion control strategy an in situ oxygen analyzer — a probe inserted directly into the flue gas duct without the need for a sampling system — should be used.

The probe should typically be located in the middle of the duct on the boiler outlet after the generating bank and economizer but before the air heater (see Figure). On larger boilers, challenges caused by tramp air and/or flue gas stratification can be encountered. Tramp air infiltration may occur on older units, causing oxygen readings to appear higher than they actually are in the furnace. When this happens, maintenance should be completed to eliminate air leakage to the best degree possible such that a relatively accurate oxygen reading is possible. Stratification results when flue gas flow is not even across the exit duct, a situation that is not uncommon during the normal operation of bigger boilers. When this is encountered, a manual duct traverse with a handheld meter should be performed to determine the best location for measurements, and multiple oxygen probes should be considered. The latest generation of oxygen meters is equipped with functionality such as online calibration capability, calibration diagnostics, and plugged diffuser/filter alarms (for boilers with fly ash or other particulate in the flue gas). These features are beneficial in keeping the important oxygen measurement device fully operational to the highest degree possible.

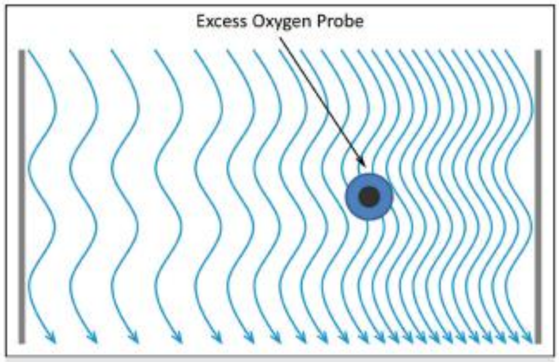


Fig: Flue gas stratification in the boiler exit duct may require an off-center position for the oxygen probe or the use of multiple

Air flow measurement: Boiler air flow measurement is often a challenge because of the physical arrangement of fans and ductwork. Ducts often have odd geometries and many turns, with dampers, expansion joints, internal restrictions, conditioning vanes and service access doors. Often internal restrictions are not even documented. For traditional air flow instruments, specifications typically call for extended straight upstream and downstream sections of duct with no bends, expanders, dampers or obstructions in front of the measurement point. On many units, this length of straight run cannot be found, and simply installing the instruments can be a challenge. Measurements may be needed in thin wall or fiberglass ducts, and there may be little clearance on the outside of the ducts. In such installations where the physical constraints are quite different from what a traditional flow meter would like to see, a good choice for the application is often an averaging Pitot tube (see Figure).

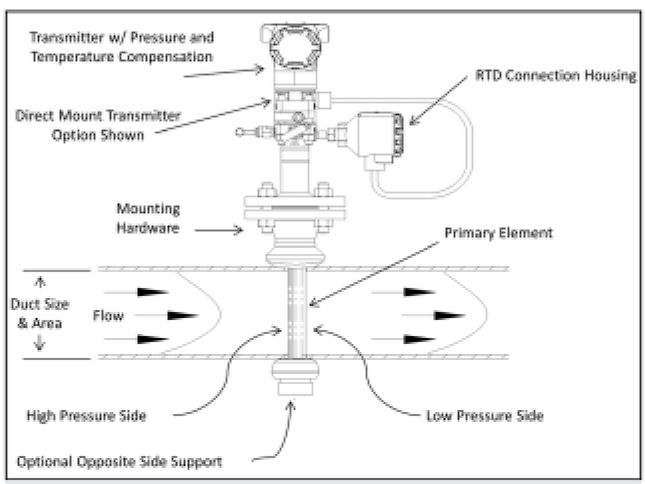


Fig: Averaging Pitot tube instrument with direct-mount transmitter and pressure/temperature compensation

The averaging Pitot tube mounts easily in all shapes of duct, can provide a good measurement across a wide load range, has low permanent pressure loss and has a relatively low installed cost. These devices can simultaneously measure differential pressure, static pressure and temperature to calculate dynamically compensated mass flow in real-time and, perhaps most important, can be calibrated in place for unusual duct arrangements and where limited straight run is available (see Figure). To calculate an optimal K factor (or flow coefficient), inline flow calibration is used if the duct is irregular or a disturbance upstream of the flow element occurs. This involves sampling the flow at multiple points and under varying flow rates using a single-point Pitot tube. Using this technique, the true nature of the flow profile can be determined, and a reliable air flow measurement (typically, accurate to about 2 percent with good repeatability) can be obtained where it is needed on the boiler.

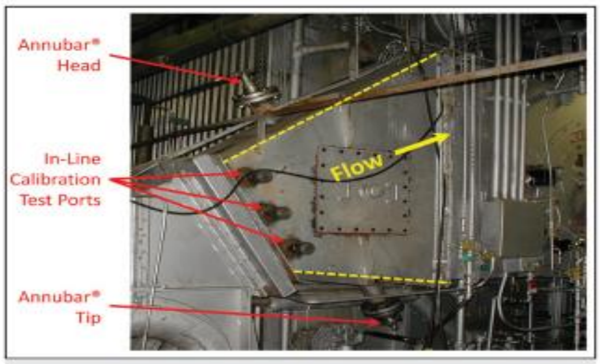


Fig: Air flow measurement in a short transition duct with ports to allow in-line calibration during setup

Fuel flow measurement: The approach to optimizing combustion is fundamentally a drive toward achieving mass balance between fuel and oxygen, so fuel measurements should be of the mass flow type. An important question to answer when selecting instruments for fuel flow is simply, what varies? If process variables are all nearly constant, volumetric flow measurement is the least expensive choice, and it can be a good one. However, changes in the rate of fuel flow, temperature, pressure or heating value require a meter that is able to address these changes or one that is relatively insensitive to them. Each variation may induce errors in volumetric meters used on gaseous fuels. Pressure changes will be present in nearly every fuel measurement because of pipe-friction-induced pressure loss between the regulator and the meter, regulator droop and barometric variation. When fuel pressure and temperature changes are the primary cause of variation, external compensation can be added to the flow meter to improve its accuracy.

A better option is to utilize multivariable mass transmitters that compensate for changing pressure, temperature or flow rate at the instrument. Some boilers, however, are fueled with process gas, waste gas, or whatever may be a least-cost fuel at a point in time. Since the heating value of such fuels can vary over a wide range, a direct mass Coriolis flow measurement is typically best in this situation. All types of mass flow meters improve turndown, which helps when the boiler experiences wide load swings. In addition, any changes in feed water temperature will require corresponding changes in firing rate. Flow measurement generally involves weighing trade-offs between a number of factors. Other issues that commonly influence meter selection and installation method include meter pressure loss (because fuel is often delivered to the boiler at low pressure), available straight run, and of course, lifecycle economic factors. Knowing the fuel mass rate means knowing the rate at which energy (Btu/calories) is being delivered to the burners, which in turn determines the amount of air required. This makes it easier to control combustion, monitor boiler efficiency and monitor plant energy use, even with compressible fuel. Further, it makes environmental reporting easier.

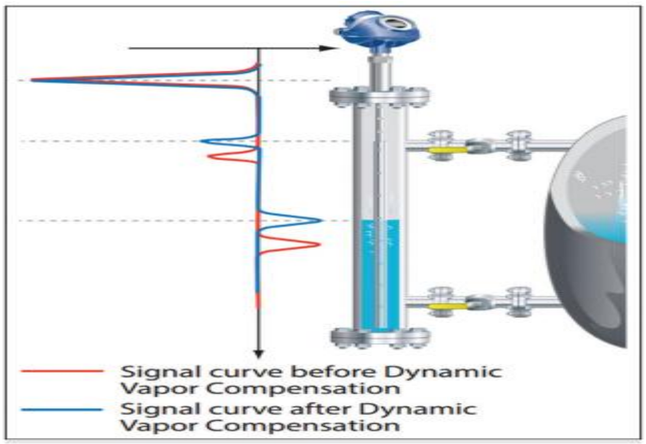


Fig: DVC works by inserting a fixed reflective object in the path of the radar waves, well above any expected liquid level. The GWR compares the measured distance to the reflector with its known distance to create a compensation value that it then applies to all readings.

Steam drum level measurement

Steam drum level measurement with a differential pressure transmittercan be a tricky business when the pressure is higher than for "low “pressure steam. What happens is that as the temperature rises, the density of water drops while at the same time that of steam rises. To compound the problem, the wet leg temperature is not well defined andits density is a third variable.A technical way around the wet leg problem is to use the following levelcapture apparatus. fig.. The constant condensation in the topconnection maintains a constant influx of hot water at equilibrium withthe steam. This maintains the heat and ensures both wet leg and measurement sections are at the same temperature (that of the water inthe steam drum), below the apparatus, the two impulse lines are in closecontact and therefore at the same temperature. Whatever the density ofthe water is, it is the same in both legs and cancels out in the differential measurement.

UNIT III

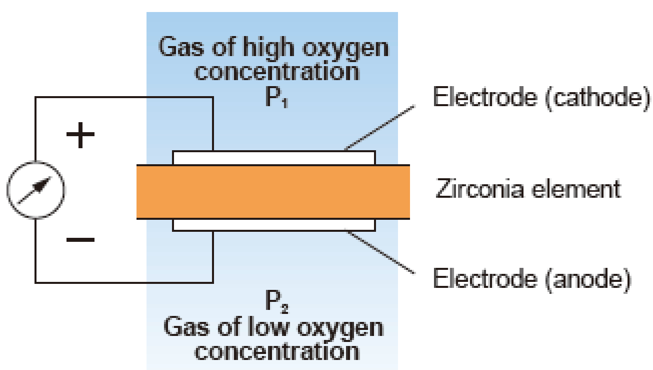
ANALYSERS IN POWER PLANTS

The measurement methods of the oxygen analyzers currently available in the industry can be classified into the following categories.

1. Zirconium Type Measurement System
2. Paramagnetic Type
3. Optical Type
4. Electrochemical Type

Since each of the measurement methods has its advantages and disadvantages, it is important to select an oxygen analyzer of an appropriate method for your application and usage.The following describes an overview of each of the measurement methods and their advantages and disadvantages.

(1) **Zirconia type measurement system:** Concentration cell systemA solid electrolyte like zirconia exhibits conductivity of oxygen ions at high temperature.



As shown in the figure, when porous platinum electrodes are attached to both sides of the zirconia element to be heated up and gases of different partial oxygen concentrations are brought into contact with the respective surfaces of the zirconia, the device acts as an oxygen concentration cell. This phenomenon causes an electromotive force to be generated between both electrodes according to Nernst's equation. And it is proportional oxygen concentration.

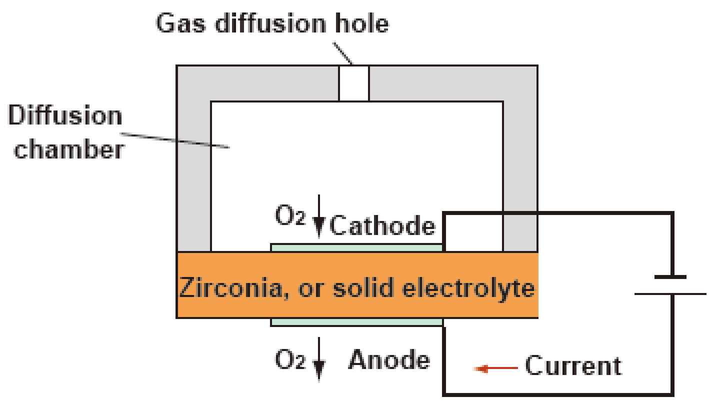
Advantages:

- Can be directly installed in a combustion process such as a boiler's flue and requires no sampling system, and response is faster.

Disadvantages:

- If the sample gas contains a flammable gas, a measurement error occurs (combustion exhaust gas causes almost no problem because it is completely burned).

(2) **Zirconia type measurement system:** Limiting Current type
As shown in the figure below, if the flow of oxygen into the cathode of a zirconia element heated to high temperature is limited, there appears a region where the current becomes constant even when the applied voltage is increased.This limited current is proportional to the oxygen concentration.



Advantages:
- Capable of measuring trace oxygen concentration.
  Calibration is required only on the span side (air).
- If the sample gas contains a flammable gas, a measurement error occurs.

Disadvantages:

- The presence of dust causes clogging of the gas diffusion holes on the cathode side; a filter must be installed in a preceding stage.

(3) **Magnetic type measurement system:** Paramagnetic system
This is one of the methods utilizing the paramagnetic property of oxygen. When a sample gas contains oxygen, the oxygen is drawn into the magnetic field, thereby decreasing the flow rate of auxiliary gas in stream B. The difference in flow rates of the two streams, A and B, which is caused by the effect of flow restriction in stream B, is proportional to the oxygen concentration of the sample gas. The flow rates are determined by the thermistors and converted into electrical signals, the difference of which is computed as an oxygen signal.

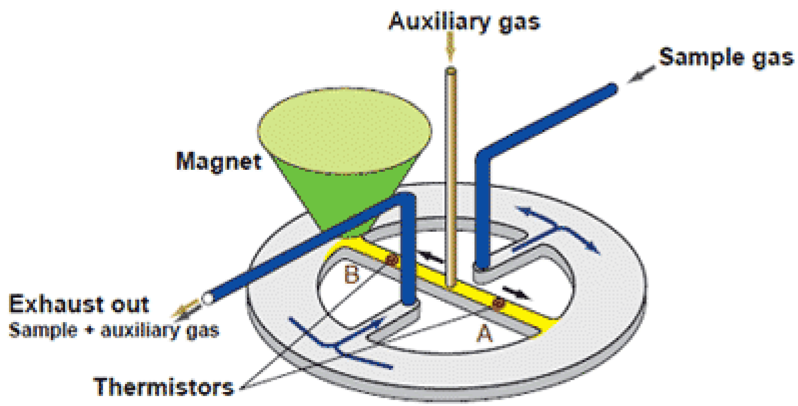
Advantages:

- Capable of measuring flammable gas mixtures that cannot be measured by a zirconia oxygen analyzer.

- Because there is no sensor in the detecting section in contact with the sample gas, the paramagnetic system can also measure corrosive gases.
- Among the magnetic types, the paramagnetic system offers a faster response time than other systems.
- Among the magnetic types, the paramagnetic system is more resistant to vibration or shock than other systems.

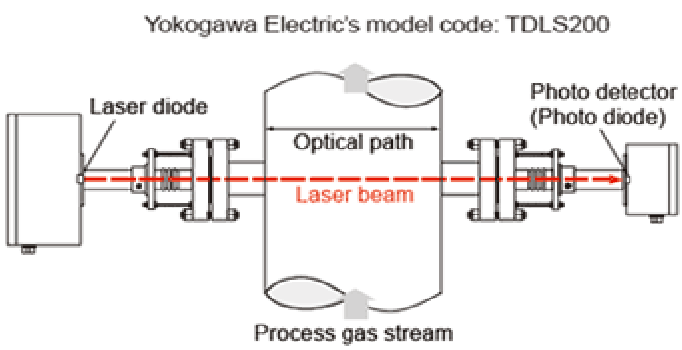
Disadvantages:

- Requires a sampling unit corresponding to the sample gas properties or applications.



(4) **Optical type:** Tunable Diode Laser measurement system

Tunable Diode Laser (or TDL) measurements are based on absorption spectroscopy. The TruePeak Analyzer is a TDL system and operates by measuring the amount of laser light that is absorbed (lost) as it travels through the gas being measured. In the simplest form a TDL analyzer consists of a laser that produces infrared light, optical lenses to focus the laser light through the gas to be measured and then on to a detector, the detector, and electronics that control the laser and translate the detector signal into a signal representing the gas concentration.

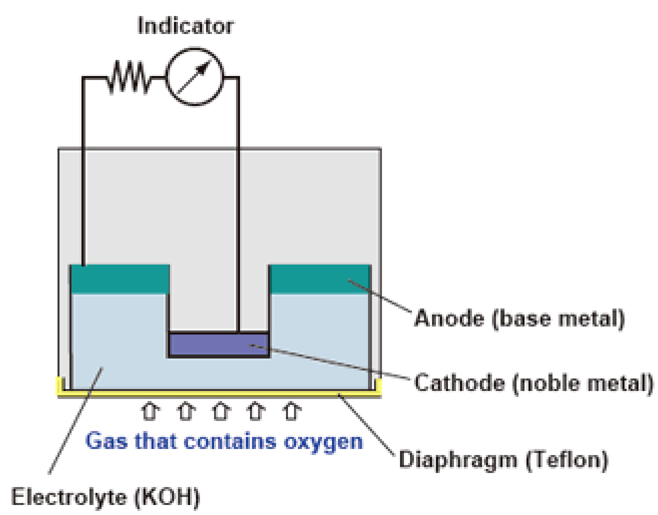


Advantages:

- Capable of measuring a number of near infrared absorbing gases in difficult process applications.
- Capability of measuring at very high temperature, high pressures and under difficult conditions (corrosive, aggressive, high particulate service).
- Most applications are measured in-situ, reducing installation and maintenance costs.

Disadvantages:

- The installation of the flange is necessary for both sides of the process.



Advantages:

- The detecting system can be made compact; this measurement system is available in portable or transportable form.
- Relatively inexpensive in comparison with oxygen analyzers of other measurement systems.

UNIT- IV

CONTROL LOOPS IN BOILER

Steam drum: The steam drum is a key component in natural, forced and combined circulation boilers. The functions of a steam drum in a subcritical boiler are:

• Mix fresh feedwater with the circulating boiler water.

• Supply circulating water to the evaporator through the downcomers.

• Receive water/steam mixture from risers.

• Separate water and steam.

• Remove impurities.

• Control water chemical balance by chemical feed and continuous blowdown.

• Supply saturated steam

• Store water for load changes (usually not a significant water storage)

• Act as a reference point for feed water control

Steam drum principle: The steam drum principle is visualized in figure. Feedwater from the economizer enters the steam drum. The water is routed through the steam drum sparger nozzles, directed towards the bottom of the drum and then through the down comers to the supply headers. This recovery boiler operates by natural circulation. This means that the difference in specific gravity between the down coming water and uprising water / vapor mixture in the furnace tubes induces the water circulation. Drum internals help to separate the steam from the water. The larger the drum diameter, the more efficient is the separation. The dimensioning of a steam drum is mostly based on previous experiences. A drawing of a steam drum cross-section is shown in figure.

Water and steam in a steam drum travel in opposite directions. The water leaves the bottom of the drum to the downcomers and the steam exits the top of the drum to the superheaters. Normal water level is below the centerline of the steam drum and the residence time is normally between 5 and 20 seconds. A basic feature for steam drum design is the load rate, which is based on previous experiences. It is normally defined as the produced amount of steam (m3 /h) divided by the volume of the steam drum (m3). Calculated from the residence time in the steam drum, the volumetric load rate can be about 200 for a residence time of almost 20 seconds in the pressure of about 80 bar. The volumetric load rate increases when the pressure decreases having its maximum value of about 800. As can be thought from the units, the size of the steam drum can be calculated based on these values.

Steam separation: The steam/water separation in the steam drum is also based on the density difference of water and steam. It is important to have a steady and even flow of water/steam mixture to the steam drum. This is often realized with a manifold (header) designed for partitioning of the flow. There are different kinds of devices for water separation such as plate baffles for changing the flow direction, separators based on centrifugal forces (cyclones) and also steam purifiers like screen dryers (banks of screens) and washers. . The separation is usually carried out in several stages. Common separation stages are primary separation, secondary separation and drying. Figure shows a drawing of the steam drum and its steam separators. One typical dryer construction is a compact package of corrugated or bent plates where the water/steam mixture has to travel a long way through the dryer. One other possibility is to use wire mesh as a material for dryer. The design of a dryer is a compromise of efficiency and drain ability - at the same time the dryer should survive its lifetime with no or minor maintenance. A typical operational problem related to steam dryers is the deposition of impurities on the dryer material and especially on the free area of the dryer (holes).

In this particular steam drum, the primary separators are cyclones (figure). These enable the rising steam/water mixture to swirl, which causes the heavier water to drop out of the cyclones and thus let the lighter steam rise above and out of the cyclones. The steam, which is virtually free of moisture at this point, continues on through the secondary separators (dryers), which are called demisters. Demisters are bundles of screens that consist of many layers of tightly bundled wire 4 mesh. Demisters remove and capture any remaining droplets that may have passed through the cyclones. The water that condenses from the demisters is re-circulated through the boiler's circulation process.

Steam purity and quality Impurity damages impurities in steam causes deposits on the inside surface of the tubes. This impurity deposit changes the heat transfer rate of the tubes and causes the superheater to overheat (CO3 and SO4 are most harmful). The turbine blades are also sensitive for impurities (Na+ and K are most harmful).

The most important properties of steam regarding impurities are :

- Steam quality, Water content: percent by weight of dry steam or moisture in the mixture

• Solid contents, Steam purity: parts per million of solids impurity in the steam quality There are salts dissolved in feedwater that need to be prevented from entering the superheater and thereby into the turbine. Depending on the amount of dissolved salt, some impurity deposition can occur on the inner surfaces of the turbine or on the inner surface of superheater tubes as well. Steam cannot contain solids (due to its gaseous form), and therefore the water content of steam defines the possible level of impurities. The water content after the evaporator (before superheaters) should be << 0.01 %-wt (percent by weight) to avoid impurity deposition on the inner tube surfaces. If the boiler in question is a high subcritical-pressure or supercritical boiler, the requirements of the steam purity are higher (measured in parts per billion). Steam purity The solid contents are a measure of solid particles (impurities) of the steam. The boiler water impurity concentration, solid contents after the steam drum and moisture content after the steam drum are directly connected: e.g. If the boiler water impurity concentration is 500 ppm and the moisture level in the steam (after the boiler) 0,1 %, the solids content in the steam (after the boiler) is 500 ppm * 0,1 % = 0,5 ppm. Continous blow down When water is circulated within the steam generating circuits, large amounts are recalculated, steam leaves the drum and feedwater is added to replace the exiting steam. This causes the concentration of solid impurities to build up. To continuously remove the cumulative amounts of concentrated solids, a sparger the length of the drum is situated below the centerline. The continuous blowdown piping is used to blow the accumulations out of the drum and into the "continuous blowdown tank".

Sampling is done to properly set the rate of blow down based upon allowable amounts of identified solids. A photograph of the blowdown piping in the recovery boiler is shown in figure . [Andritz] Steam drum placement Natural circulation boilers In natural circulation boilers the steam drum should be placed as high as possible in the boiler room because the height difference between the water level in the steam drum and the point where water begins its evaporation in the boiler tubes, defines the driving force of the circuit. The steam drum is normally placed above the boiler. Controlled circulation and once-through boilers.Shows photos from the installation process of the recovery boiler steam drum. For controlled circulation and once-through boilers the steam drum can be placed more freely, because their circulation is not depending on the place of the steam drum (pump-based circulation). This is a reason why controlled circulation and once-through boiler have been preferred in e.g. boiler modernizations, when the biggest problem is usually lack of space.Installation of steam drums (Andritz). Other aspects of steam drum design

Inside the steam drum there are also different kinds of auxiliary devices for smooth operation of the drum. The ends of feedwater pipes are placed below the drum water level and must be arranged so that the cold-water flow will not touch directly the shell of the drum to avoid thermal stresses. The water quality is maintained on one hand by chemical feed lines, which bring water treatment chemicals into the drum, and on the other hand by blowdown pipes which remove certain portion of the drum water continuously or at regular intervals. A dry-box can be placed before the removal pipe for steam. It consists of a holed or cone-shaped plate construction allowing a smooth flow distribution to a steam dryer.

Feedwater system This chapter describes the feedwater system part of the power plant process prior the boiler, i.e. between the condenser (after turbine) and the economizer. The feedwater system supplies proper feedwateramount for the boiler at all load rates. The parameters of the feedwater are temperature, pressure and quality. The feedwater system supplies also spray water for spray water groups in superheaters and reheaters. The feed water system consists of a feed water tank, feed water pump(s) and (if needed) highpressure water preheaters.

Feedwater tank A boiler should have as large feed water reserve as is needed for safe shutdown of the boiler. The heat absorbed by the steam boiler should be taken into account when dimensioning the feed water reserve (feed water tank). The exact rules for the choice of feed water reserve are included in respective standards. The feedwater tank of the recovery boiler is shown in figures 9, 10 and 11. Condensate (from turbine) and fully demineralized (purified) makeup water are the normal inputs to the feed water tank. Gas removal takes place in the deaerator before condensate and makeup water reach the feed water tank. The deaerator handles feedwater gas removal and chemical feeding. Lowpressure steam is used to remove gases containing oxygen from the feedwater. The steam used for gas removal (including gases containing oxygen) continues from feed water tank to a specific condenser, where the heat from low-pressure steam is recovered. The feedwater tank is heated with low-pressure steam (usually 3-6 bars). The steam assists the gas removal from the feedwater tank.

Feedwater pump: The feedwater pumps lead feedwater from the 7 feedwater tank to the boiler. Regulations allow using only one feedwater pump for (very) small boilers, whereas for bigger units at least two feedwater pumps are needed. Usually there are two similar and parallel-connected feedwater pumps with enough individual power to singularly supply the feedwater needs of the boiler, in case one was damaged. A photo of a feedwater pump being manufactured is shown in figure 12. Feedwater pumps are usually over dimensioned in relation to mass flow rate of steam in order to have enough reserve capacity for blowdown water and soot blowing steam etc. Smaller feedwater pumps are always electric powered, while feedwater pumps for bigger capacity may be steam powered. Feedwater pump manufacture (Sulzer) Normally the feedwater tank is placed above the feed water pumps in the boiler room. The difference in altitudes between feedwater pumps and feedwater tank is defined by a parameter called NPSH (net positive suction head). It is related to the cavitation of feedwater pumps and it defines the minimum altitude difference between feedwater pump and feedwater tank. The feedwater pump head [N/m2] can be calculated according to the following equation:

$$\Delta p_{pump} = p_p + \Delta p_{flow} + \rho g H_{geod}$$

where pp is the maximum operating pressure at the steam drum, Δpflow is the loss in the feedwater piping and economizer, and ρgHgeod is the pressure required to overcome the height difference between feed water tank lower level and drum level (visualized in figure 13). Feedwater heaters There are two types of feedwater heaters in power plant processes: high-pressure (HP) and lowpressure (LP) feedwater heaters. Of these, the HP feedwater heaters are usually situated after the feed water pump (before the economizer) in the power plant process. LP feedwater heaters are normally situated between condenser and feed water tank (deaerator) in the process. Highpressurefeedwater heaters are also called closed-type feedwater heaters since fluids are not mixed in this type of heat exchanger. Normal construction of a HP feedwater heater is a shelland-tube heat exchanger - feedwater flows inside the tubes and steam outside the tubes (on shell side). In a large conventional power plant the typical arrangement of feedwaterheaters is a block of open-type (LP) feedwater heaters and a block of HP feedwater heaters after the feedwater pump in the process. The typical number of LP feedwater heaters in a large power plant is 2 and the number of HP feedwater heaters 5, respectively. The procedure for optimal placement of HP feedwater heaters begins by defining the enthalpy difference between feed water pump outlet and economizer inlet. This enthalpy difference is then divided by the amount of HP feedwater heaters and the result is the enthalpy rise in every HP feedwater heater stage

Steam temperature control: Steam consumers (e.g. turbine, industrial process) require relatively constant steam temperature (±5°C); therefore means of boiler steam temperature control is required. Steam temperature control system helps maintaining high turbine efficiency, and turbine material temperatures at a reasonable level at boiler load changes. An uncontrolled convective superheater would cause a rise in steam temperature as the steam output increases.

Methods for steam temperature control are:

• Water spraying superheated steam

• Steam bypass (superheater bypass)

• Flue gas bypass

• Flue gas re-circulation

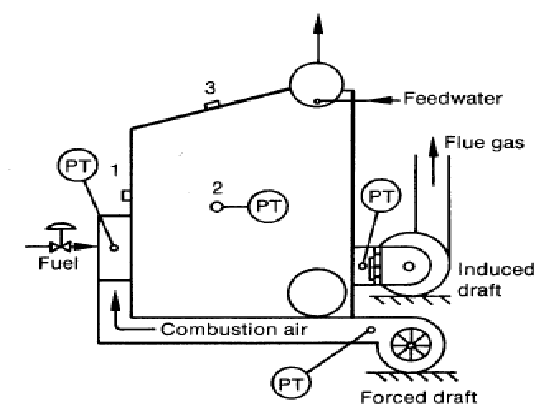
• Heat exchanger system

• Firing system adjustment

Measurement of Furnace Draft:

Figure demonstrates the choice of pressure tap locations for measuring furnace draft. The pressure connection on most boilers is located on the front, side, or roof of the furnace.Although the measurements at these three locations would be for the same furnace chamberof a particular boiler, the measurement values would differ due to the differing stack or chimneyeffects. The measurements at different elevations will differ by approximately 0.01 inchH20 per foot elevation. The measurement in the roof of the furnace will be the highest value.Since it is necessary to have negative pressure at all points, the value at the furnace roofbecomes the controlling factor in determining the desired set point for the control of furnacedraft. Thus, if the pressure at the furnace roof is to be minus 0.1 inch of H,O and the connectionfor measuring furnace draft is located at an elevation 15 feet below the furnace roof,then the set point for this control loop should be approximately -0.25 inch of H20. On alarge boiler the connection might be as much as 50 feet or more below the roof elevation. Inthis case, the set point should be approximately -0.6 inch of H20 or at a lower pressure.Because of the very low pressure involved, the pressure connection should be large enoughso that slight changes in the furnace draft can be very quickly felt by the measuring instrument.General practice is shown by Figure 15-2. The actual connection is a 2-inch pipe size, andthe piping to the instrument is often **3/4** to 1 inch in

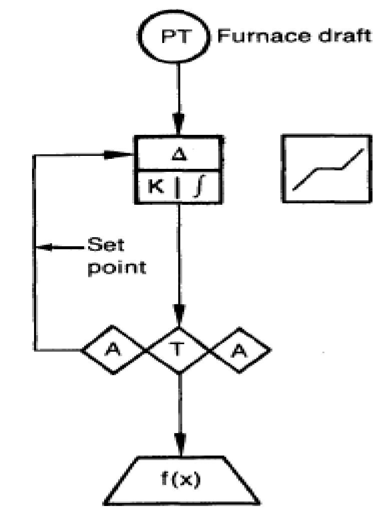
size. The 2-inch connection is provided with a tee and a plug in order that the plug can be removed and the connection easily cleaned. The piping size shown is typical for the older furnace draft transmitters that have significant displacement. Modem transmitters used for furnace draft measurement have very low displacement. Recent response tests with these transmitters have proven that good response canbe obtained with tubing as small as **3/8** inch.
In some cases involving balanced draft coal or solid fuel boilers, it is appropriate to drilla-small hole (approximately 1/8 inch) in the plug. This allows a small amount of air to bedrawn into the furnace at all times to help prevent soot or ash from plugging the connection. This procedure should never be used with pressure-fired boilers. For these boilers it is necessarythat the instrument connection systems be free of all leaks in order to avoid the introduction of H,O vapor, soot, or ash into the connecting piping.For most boilers a furnace draft or pressure transmitter will operate normally within apressure range of less than 1 inch of H20. For presenting the information to an operator, anormal instrument pressure range of +O. 1 to -1.0 inch of H,O is typically used. Such a narrowrange is not normally satisfactory for control purposes. On fast changes of flow capacity orunder abnormal operating conditions, the actual pressure or draft may exceed this range andthus not provide the controller with all the intelligence necessary during the period of change.Furnace draft measurement is also subject to considerable process "noise." The use of anarrow range transmitter tends to accentuate the effect of such noise in the measurement. Anadditional factor is primarily a limitation of analog control. In this case it is quite often impossibleto reduce the controller gain to a low enough value. Therefore, the general practiceis therefore to use a control transmitter range of approximately + 1 .*O* to -5.0 inches of H_20.



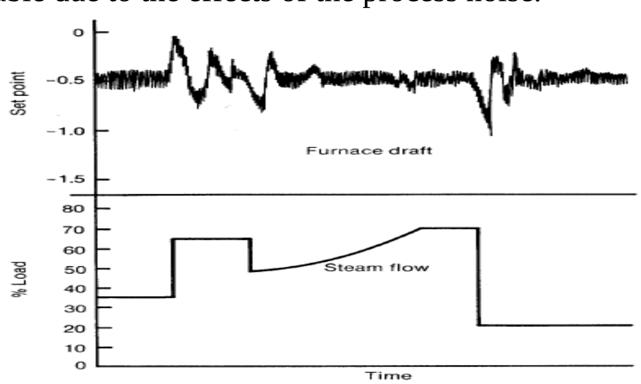
Furnace Draft Control Using Simple Feedback Control

The simplest form of the furnace draft control loop uses a simple feedback control loop. In this case the control of air flow is usually assigned to the forced draft with the furnace draftcontrol regulating the level of induced draft. Generally, it is most desirable to measure airflow on the forced draft side of the furnace. Assigning the air flow control to forced draft tendsto reduce interaction between the air flow and the furnace draft control loops.The control arrangement is shown in Figure 15-3. The air flow capacity is changed bymodulating the forced draft. **As** shown here, the resulting change in furnace draft feeds backto the controller, causing a series change to the induced draft. It is also possible to assign theair flow change to the induced draft with the series action taking place on the forced draft. Inthat case the controller action would be reversed.

On many installations a control loop of this type is very difficult to tune for satisfactory results under dynamic load changing situations. The series action of the control allows toomuch time difference between the changes to the forced and induced drafts. Theoretically, these should be moving in parallel.
In addition, the large amount of process noise as a percentage of the measurement signal tends to require tuning adjustments of lower than desirable gain and slower than desired integral. In some cases, if a standard feedback control alone is used, it may be necessary to remove all proportional action and rely on integral control alone. This tends to accentuate the problem of the series time delay.
One solution to this problem is to use a differential gap controller or a nonlinear controllersuch as an error squared controller. In the differential gap controller, no control action takesplace as long as the furnace draft is within an adjustable band around set point. The gap isadjusted so that the normal process noise does not cause control action. Only outside this banddoes control action occur. In the nonlinear error-squared control, all proportional and integralinsensitive to process noise and also to required control action when close to set point. Thisalso tends to accentuate the problem of the series time delay.



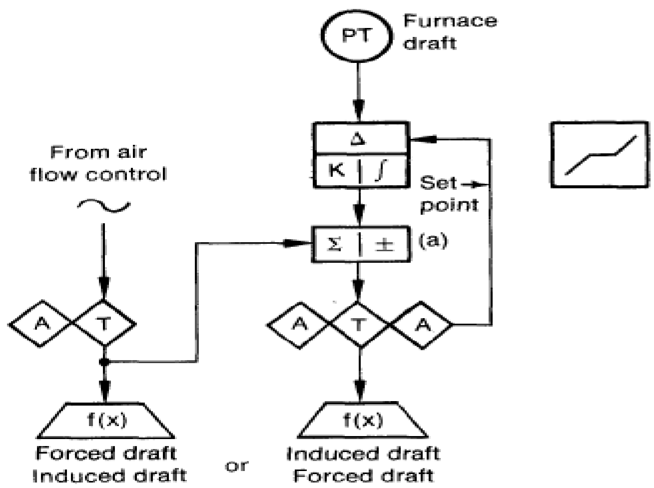
For comparison purposes, Figure demonstrates the performance of a typical feedback furnace draft control loop. The excursions tend to be large with respect to the set point value, and the control tends to be unstable due to the effects of the process noise.



Such a control loop may be the single most difficult boiler control loop. Assuming a measurementat the furnace roof, the goal is to hold the furnace draft to a set point of -0. l inchof H,O with an excursion range of plus or minus 0.05 inch of H,O, while the process noiseis usually a minimum of f 0.1 inch of H,O and a typical overall capability of the fans at 6 to10 inches of H20. For large electric utility boilers the fan capability may be 25 inches of H,Oor more, but the control performance described is still required.

Furnace Draft Control Using Feedforward-plus-Feedback Control

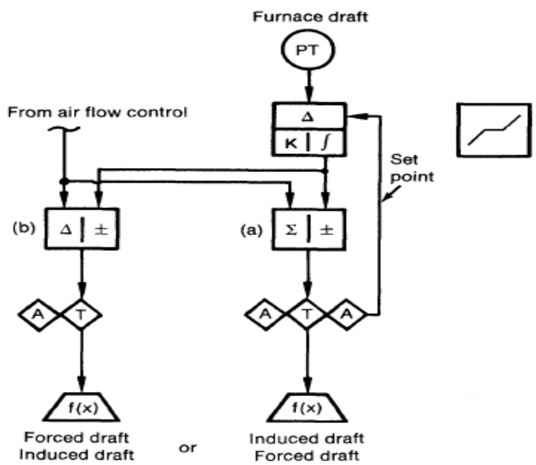
Figure demonstrates an improved control loop for the control of furnace draft. In thiscase the signal to the forced draft control device is added in the summer (a) to the output ofthe furnace draft feedback controller. In this way the series time lag between forced and inducedcontrol action is eliminated. Note that it is necessary to provide a bias function in the



summer (a). This is necessary so that the output of the furnace draft controller will operate normally in the middle portion of its output range. This allows the controller to equally add or subtract from the feed forward signal as necessary. **A** proper control alignment for the summer (a) would show it having gains of 1 ***.O*** on both inputs and with bias of -50 percent. In applying this or other feed forward control it is necessary to parallel the flow characteristics of the two parallel control devices (in this case forced and induced draft). If this is not done, the two will not provide the proper parallel effect, and much of the benefit of the feed forward control may be lost. It is also necessary to select the proper feed forward signal. Measured air flow should not be used as the feed forward signal. **A** positive feedback effect and aeries time lag is introduced into the loop due to interaction between the air flow and the furnace draft measurement. Figure shows performance of the feed forward system on a comparative basis with the feedback arrangement. In this case the capacity changes can be made with much smaller deviations from the furnace draft control set point. Because of the feed forward action, thefurnace draft controller can be considerably slower in action without reducing the effectiveness of the control loop. This adds control stability by reducing the gain and integral requirements and thus reducing the effect of process noise. Since the forced and induced drafts operate in parallel, any potential interaction between the forced and the induced draft control is significantly reduced.

Furnace Draft Control Using Push-Pull Feed forward-plus-Feedback Control

In the diagram shown in Figure, the feedback portion of the control loop is improved by applying it in a push-pull manner. The feed forward portion of the loop is identical to the feed forward portion of the system described in Figure. The control signal from the air flow controller is used as an input to the summer (a). The other input to this summer is the output of the furnace draft feedback controller. Properly aligned, both of these inputs would have a gain of 1.0. As before, a -50 percent bias is applied to the output of the summer (a).An additional function, difference (b), uses the same two inputs as the summer (a). When properly aligned, both inputs to the difference function (b) have a gain of 1.0, and a bias of+50 percent is applied to its output. This arrangement provides improved dynamic performance by allowing the feedback controller to add to the induced fan control signal while simultaneously subtracting from the forced draft control signal. The description above covers the manipulation of the signals only. The feedback controller is direct acting with a more negative furnace pressure input producing a more negative output control signal. The system can thus adjust on a dynamic basis for any control result that differs from that calibrated into the basic feed forward system. For example, it is more “forgiving” in regard to the paralleling requirements of the calibration of the forced and induced control devices. In the basic feed forward system, the control signal vs. flow characteristics are used to match the forced and induced drafts. If flow resistances change, the matching deteriorates and affects the feed forward performance. This arrangement tends to automatically compensate for these changes in flow resistance.



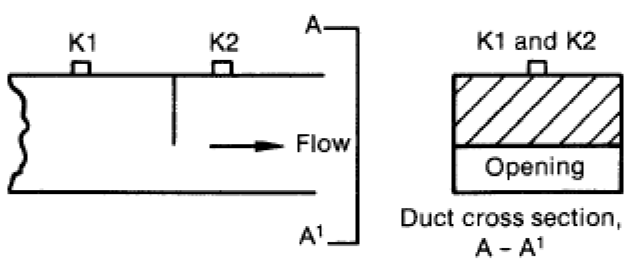
Improved performance of the feed forward portion of the system reduces further the control demand on the feedback portion of the control loop. The result is improved control stability through further reduction in the gain and integral requirements of the feedback controller and, thus, lower effects from the process noise.

While the feed fonvard-plus-feedback arrangements discussed apply equally to industrial and the largest electrical utility boilers, additional controls for implosion protection should be applied to large electric utility boilers.

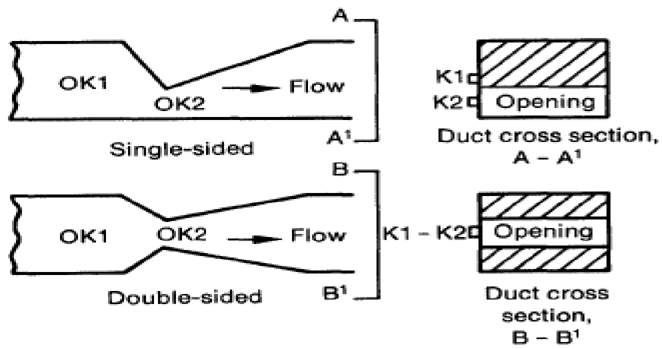
Measurement and Control of Combustion Air Flow:

Combustion air flow is customarily measured with some form of primary measuring element

that is installed as a part of the boiler duct and fan system. This is used with a differential pressure measurement device. The ducts are of various shapes and sizes; they also have numerous90 degree bends, short straight runs, and other features that are normally considered to be detriments to accurate measurement. These factors have a very significant effect on the actual flow coefficients and their characteristics of flow vs. differential pressure. This is one factor that necessitates field calibration by using the results of boiler combustion tests.
An excellent discussion of this subject and solutions to some of the measurement problems are given in the ISA Technical Paper “Air Flow Measurement Techniques” by Lyle F. Matzo the Westinghouse Electric Corporation. This paper appears in the proceedings of the **1984 ISA** Power Symposium.
Any permanent pressure drop in the system as a result of the installation of the primary element increases the requirement for power to drive the combustion air fans. For this reason it is desirable that the primary element have a low differential pressure at full boiler capacity. Typically, the secondary differential pressure measuring devices have design differentials of1 to 2 inches of water at maximum signal output.
Different types of primary elements have different discharge coefficients. The result is difference in permanent pressure loss. The choice between primary elements based on permanent pressure loss (and, thus, fan power consumption) may be difficult to justify on an economic basis. Consider that the difference might be that of discharge coefficients of 0.6 and0.85. **If** the full load differential pressure is 1 inch of H,O, the permanent pressure loss would differ by 0.25 inch of water at full load. This would, however, be reduced to 0.0625 inch ofH20 at 50 percent load and 0.0156 inch of H20 at 25 percent load. One potential primary device is an orifice segment in the forced draft duct. Figure shows this type of device. It is simple to design and install, but its drawback is lower pressure recovery and, thus, greater permanent pressure drop. Considering the individual nature of the ductwork, an accurate design is impossible. An approximate design combined with field calibration can produce good results. The Martz paper mentioned above furnishes valuable insight into this method of measurement.

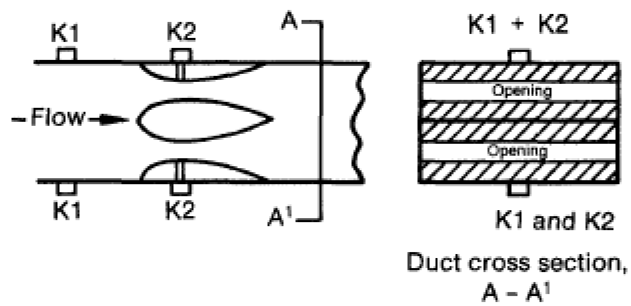


An approximate design can be made by considering the duct as a round duct and designing an orifice plate in a standard manner. The *d/D* (orifice diameter pipe diameter) is then converted to an area ratio ***(a/A),*** which will be the square of the *d/D* ratio. Using the area ratio, the opening area can be determined. This area is subtracted from the duct cross-section area to yield the area of the orifice segment.
In order to reduce the permanent pressure loss of the measuring device, a Venturi-typeduct segment, as shown by Figure, can be installed. The design of such a duct segment should be undertaken only by someone with good design basis information, such as a boiler manufacturer. This does not assure a good design, however, since the author experienced one case in which a design for 2 inches of H20 differential yielded an actual differential pressure of 8 inches of H20. A recalculation confirmed the original design.



Further reduction in permanent pressure loss can be obtained by using an air foil design, as shown in Figure 16-3. The design of an air foil also requires background of such a design along with empirical data that is based on the actual results of previous air foil designs. Airfoil designs are usually made by boiler manufacturers. A primary device of this type is also somewhat less expensive to construct than the venturi duct section.

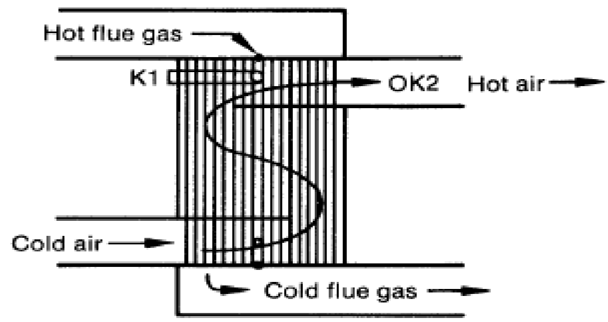
Another technique that requires no additional power consumption is to the use the pressure drop across the boiler parts. One method is the use of the pressure drop across the air side of



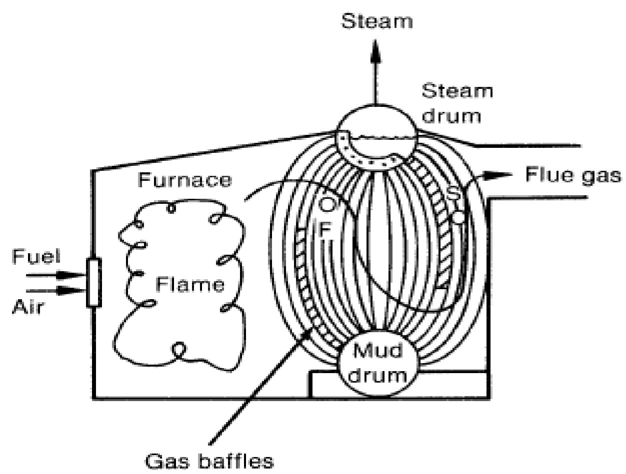
Note: K1 and K2 are pressure connections for ΔP.

a tubular air preheater, as shown in Figure. There are usually 2 or more inches of H,Oavailable at full boiler load. In most such air preheater arrangements, the difference in elevation
between the pressure connections requires compensation for the chimney or stack effectdue to the difference in temperatures. The method of connection shown in Figure 16-4 willusually provide the necessary compensation. Using the preheater pressure drop is not a satisfactory method with a rotary regenerative air preheater because of variable flow path cleanliness and variable seal leakage.

Since the combustion air accounts for over 90 percent of the mass of the flue gas productsof combustion, a measurement of flue gas flow can be used as an inferential measurement of combustion air flow. Figure 16-5 shows this method, which uses the pressure or draft differential across the boiler tube passes. The use of such a measurement tends, however, to producea greater interaction between the fuel and air flow control loops. A further disadvantage is thatsuch an air flow measurement is affected by soot or other foreign deposits on the boiler tubes. Another disadvantage is the unavailability in many cases of sufficient draft loss. **As** shown there, a difference in elevation of the pressure connections is used to compensate.

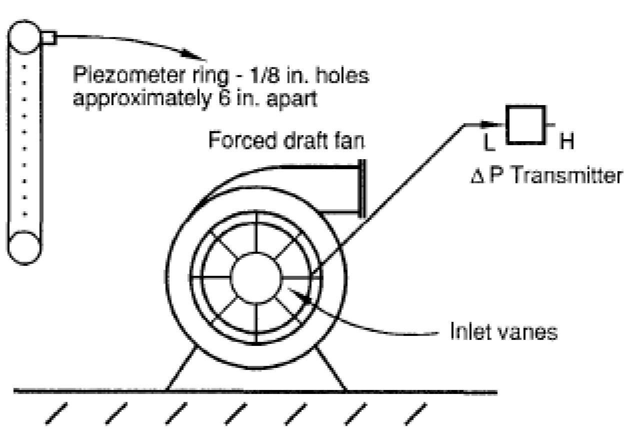


Note: K1 and K2 are pressure connections for ΔP.

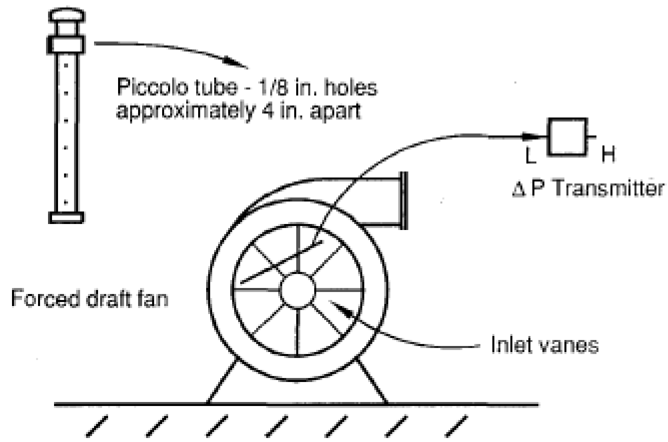


Note: F and S are pressure connections for ΔP.

Other differential pressure primary element devices that can be used are various devices based on the Pitot principle. In the Pitot tube, the pressure differential is the difference between the static pressure and the velocity head or pressure. Such devices are the PitotVenturi, thepiezometer ring, the "piccolo" tube, the Annubar'", and other forms of the Pitot tube. Insome cases these are used in multiples in order to obtain averages of different points withinthe duct. For these devices the permanent pressure loss is very small and, thus, as comparedto the restriction devices some power saving results.



The piezometer ring and the "piccolo" tube work on the same principle. They are usually mounted on the inlet to the forced draft fan to measure the velocity of the combustion air asit enters the system. This measurement may gradually deteriorate if there is a variation in the leakage rate of the combustion air preheated. These devices are shown in Figures. The averaging Pitot tube device, the most common of which is the AnnularTMis, shown in Figure. All of these devices can produce close to ***2*** inches of H,O differential at full capacity.
The calibration method for the air flow measurement by combustion testing is the preferred and most precise method when dealing with total combustion air flow. This total combustion air flow may be made up of several streams that are added together. These individual streams also require calibration. The whole air flow measuring system is in correct calibration whenthe total air flow signal matches the fuel signal and the individual flows add up to the total flow.
Calibration of the individual flows can be accomplished without the boiler operating betaking readings of Pitot tube traverses up and down and across a duct. From these, an average



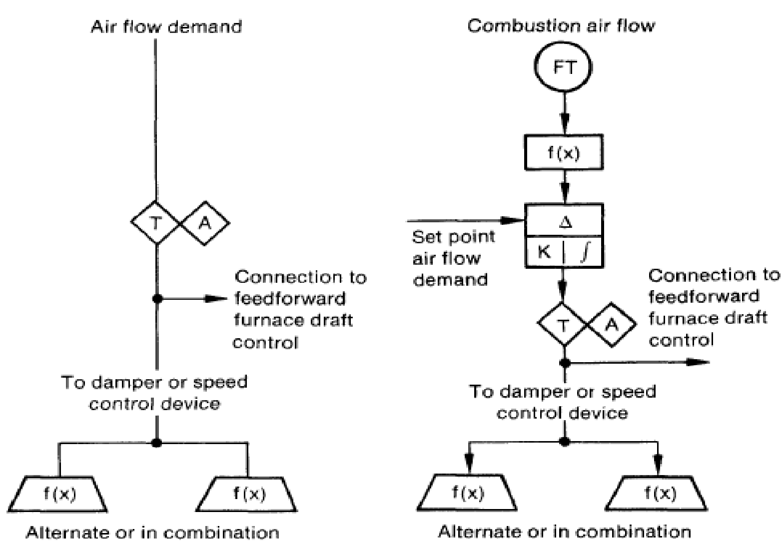
flow velocity is determined. By making corrections for air temperature of the normal flowing condition compared to the test condition, the correct calibration can be calculated. In some cases the flowing temperature can be altered with a steam coil air heater so that similar tests at a ifferent temperature, or a temperature close to the normal operating temperature, can be run. The calibration that is attained, adjusted if necessary to normal operating temperature conditions, should match the calibration achieved by the method of the preceding paragraph. If they do not, at least one of the tests is in error, and sufficient retesting should be done to assure confidence in the calibration.

Non-Inferential Methods of Air Flow Measurement

The measurement methods described above are methods for inferring air flow from airflow differential pressures with the basic flow velocity formula V = (***2gh)0.5.*** In recent yearsthe use of a fundamental measurement of mass flow is being tried. This method is an enhancement and development stemming from the "hot wire anemometer."This device has been widely used in the HVAC field for flow measurement testing. **A** heated element is in the path of the air flow. As the flow increases, heat is absorbed, the wire heating element cools, its resistance decreases, and additional electrical current is requiredto maintain the same heated state. The current can be transformed into Btu and, usingthe specific heat of the air (approximately **0.24** Btu/lb), the mass flow of air can be determined. The modem version of this device uses such elements in arrays across a duct in order thattotal air flow can be accurately measured. Because of the potential for

air flow stratification in a duct, the flow must be measured at a number of points. An approximate number of elements is one per square foot. The configuration of this device is shown in Figure. This will produce a mass flow measurement of the combustion air but must be further adjusted for variations in excess air. **A** function generator connected to the output signal produces**a** signal compensated for the desired variation in excess air as the boiler loading varies.
A continous calibration of this signal from a flue gas analysis trim control system is necessary to compensate for the effect on combustion oxygen flow from humidity variations. Only a verysmall percentage of the installations now use this method and any clearcut advantages or disadvantages have not been fully determined.

Control of Air Flow
Either open-loop or closed-loop control can be used for air flow control. An example ofeach of these two control arrangements is shown in Figure 16-10. In the open-loop arrangement the combustion air flow demand resulting from the boiler steam load is satisfied by positioning the controlled device. The expected result is a certain quantity of air flow as governed by the characteristics of the controlled device and fan speed.
At constant fan speed the position of the controlled device determines a close approximation of the flow rate. This is true only if a high percentage of the total system pressure dropoccurs across the controlled device. If this is not true and the upstream or downstream pressure varies, the flow rate will vary.
To compensate for such changes, closed-loop feedback control is used in order that theflow rate and the control signal remain equal. In this case, a deviation from the air flow setpoint feeds back to reposition the controlled device in order to maintain a given air flow. **Tbs**is a typical feedback flow controller that utilizes both proportional and integral control functions. If the flow measurement and the controlled device are reasonably well matched in flow capacity, a starting point for the controller tuning is an initial gain (proportional) setting of0.5.
The correct integral setting is geared to the total feedback time (usually a few seconds) ofthe Bow control loop. The result is typically a starting point for the integral (repeats per minute)setting of 10 rpm. The gain and integral tuning of the loop are also affected by process



(A) Open loop (B) Closed loop

noise. It should be remembered that the air flow control time response ultimately should bematched with fuel flow response. This may result in one of these loops having less than optimum
tuning. If the boiler uses both forced and induced draft fans, it is desirable to connect the control signal to the controlled device as the feedforward signal in a feed forward-plus-feedback furnace draft control loop. This tends to reduce or eliminate interaction between the air flow andfurnace draft control loops.

The arrangement above concerns installation with not more than one forced draft fan orone set of forced and induced draft fans. For the larger boilers used in electric utility installations, two or more sets of fans operating in parallel are almost universally used. Typically, most boilers of over approximately 600,000 lbs/hr steam flow maximum capacity would usetwo or more sets of fans.

If two or more fans normally operate in parallel to supply combustion air, the single-fan failure mode must be considered. If two or more fans operate in parallel, the failure of a fanwould allow the output of the operating fan or fans to be lost through the reverse flow openingsto fan suction of the non-operating fan. In general, the requirements for parallel fan systemsare:

(1) a change in gain between 1- and 2- or more fan operation;

(2) automatic closing of shutoff dampers on the inoperative fan to avoid air recirculation;

(3) the ability to balance the fan loads;

(4) usually, installation of additional control devices on the fan discharge dampers in order

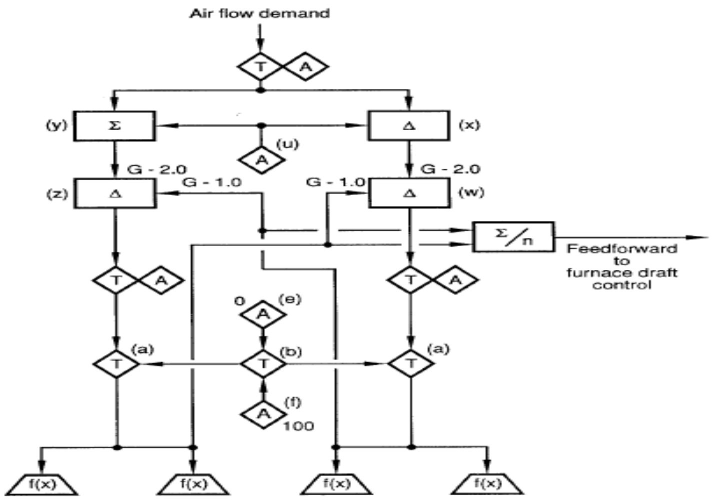
(5) opening all dampers with all fans are tripped.

to achieve tight shutoff of air flow; and

If not more than two fans are operated in parallel, the simplest approach is that shown inFigure 16-1 1. In the case of a single fan trip, digital interlock logic operates the transfer switch(a) in the control circuit of that fan and also operates the common transfer switch **(b).** In thisway the 0 percent signal (e) is connected to the controlled devices on the fan that has tripped.Should the second of two or the third fan of three trip, the switches (a) will be in their trippedcondition, but the common switch (b) will switch, admitting the 100 percent control signal (f)to all sets of control drives.The shutoff damper control devices are calibrated for quick opening when the control signalis above 0 percent. The key to the operation is the digital interlock logic that operates theswitches (a) and (b). This logic must be designed to fit the requirements of the particular installation.

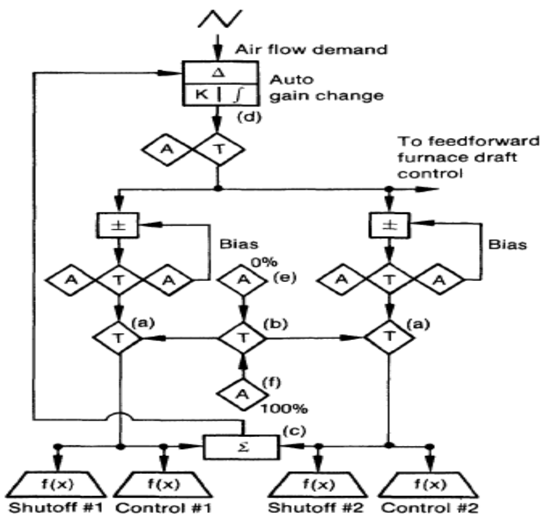
As one or the other fan is tripped and the signal to its control drive goes to 0 at the inputsof **(2)** and (w), the gain of the control for the remaining fan is doubled. If one or the other ison hand control and its control signal fixed, the gain on the other is doubled. By adding toone and subtracting from the other, the manual signal from (u) allows the operator to balancethe fan loads as desired.

If more than two sets of parallel fans are used, the control arrangement shown in Figuredoes not provide a proper solution. One solution to this control problem is shown in Figure, which could also be used if there were two fans operating in parallel. Thedamper interlocking is the same as described above, except that there would be an additional item (a) for each additional fan if there were more than two fans in parallel. The modulating control arrangement in Figure acts in the manner previously describedin the boiler load distribution of Figure. The control loop gain is automatically changed by summing the control signals in summer (c) and balancing the sum against the air flow demand signal in the high gain-fast integral controller (d). In Figure, with two fansof equal size, the input gains of summer (c) would be 0.5. The fans can be balanced manually



If the air flow control is open loop, this arrangement can be used in almost all analog ordigital control loops. If closed loop, then cascade control is being used. The controller (d) isthe secondary loop following a relatively fast primary flow control loop. This requires an orderof magnitude speed requirement of the secondary loop as compared to the primary loop. Becausethe feedback and sensing are continuous and almost instantaneous for an analog control system, the controller (d) can be tuned very fast and still have a stable output. Because of the sampling time interval and data transfer timing for a specific installation, there may be practical tuning limitations for a digital application of this technique. Such limitations might cause a large amount of detuning of the primary air flow control, resulting in unsatisfactory control performance.

In such a case, the alternate approach shown in Figure can be used. This is the same technique discussed in Section **8** and shown in Figure**.** The fan damper interlock is thesame as that of Figures**.**If a third fan is added and an additional item (a) isadded, a third input with three **0.33** input gains into summer (c) is added. To provide a thirdgain potential, a third item (j), a third input into summer (d), and three **0.33** input gains into summer (d) are added.In order to avoid significant changes in air flow when the dampers are changing position due to a fan trip, it is necessary to carefully match the control characteristics of the fans that



operate in parallel. This is accomplished by carefully matching the flow/position calibration and the timing of the controlled devices on the parallel fans. If the boiler uses both forced andinduced draft, the time and flow characteristic matching should involve all fans (both forceddraft and induced draft). In some cases the size and power of the damper control drives, andthus their stroking speed, may be different for the forced and induced drafts. Matching the characteristics in these cases results in the speeding or slowing of one of the sets of control drives.

UNIT V

TURBINE MONITORING AND CONTROL

Introduction:

Vibration is the back and forth or repetitive motion of an object from its point of rest.When a force is applied to the mass, it stretches the spring and moves the weight tothe lower limit. When the force is removed, the stored energy in the spring causes theweight to move upward through the position of rest to its upper limit. Here, the massstops and reverses direction traveling back through the position of rest to the lowerlimit. In a friction-free system the mass would continue this motion indefinitely. Allreal systems are damped, that is they will gradually come to their rest position afterseveral cycles of motion, unless acted upon by an external force. The characteristics of this vibratory motion are period, frequency, displacement, velocity, acceleration, amplitude and phase. Continued vibration of this spring mass system would onlyrepeat the characteristics shown in this single cycle.All rotating machines produce vibrations that are a function of the machine dynamics, such as the alignment and balance of the rotating parts. Measuring the amplitude ofvibration at certain frequencies can provide valuable information about the accuracyof shaft alignment and balance, the condition of bearings or gears, and the effect onthe machine due to resonance from the housings, piping and other structures.

Vibration measurement is an effective, non-intrusive method to monitor machine condition during start-ups, shutdowns and normal operation. Vibration analysis isused primarily on rotating equipment such as steam and gas turbines, pumps, motors, compressors, paper machines, rolling mills, machine tools and gearboxes. Vibration analysis is used to determine the operating and mechanical condition of equipment. Amajor advantage is that vibration analysis can identify developing problems beforethey become too serious and cause unscheduled downtime. This can be achieved byconducting regular monitoring of machine vibrations either on continuous basis or atscheduled intervals. Regular vibration monitoring can detect deteriorating or defective bearings, mechanical looseness and worn or broken gears. Vibration analysis can alsodetect misalignment and unbalance before these conditions result in bearing or shaft deterioration. Trending vibration levels can identify poor maintenance practices, suchas improper bearing installation and replacement, inaccurate shaft alignment orimprecise rotor balancing.

Basic Characteristics of Vibrations:

Modern vibration monitoring has its genesis in the mid-1950s with the development and application of basic vibration sensors, which are the heart of modern computerized condition monitoring systems. The traditional fundamental use of vibration monitoring in rotating machinery, i.e., to provide warning of gradually approached or suddenly encountered excessively high vibration levels that could potentially damage the machinery. Trending a machine’s vibration levels over an extended period of time can potentially provide early warning of impending excessive vibration levels and/or other problems and thus provide plant operators with valuable information for critical decision making to schedule a timely shutdown of a problem machine for corrective action, e.g., rebalancing the rotor. For evaluating the machine vibrations, it is usually desirable to express frequency in terms of cycles per minute, since we measure the rotational speed of machinery in revolutions per minute. This allows examination of the vibration frequency in termsof multiples of the rotational speed. Rotational speed is also known as the fundamental frequency and the multiples of the fundamentals frequencies are known as its higher harmonics or super harmonics. There are three main parameters are measured to evaluate the vibration characteristics of any dynamic system as displacement, velocity and acceleration. The peak-to-peak distance is measured from the upper limit to the lower limit, measured in mm tomicron level. The velocity of a vibrating object is continually changing. At the upper and lower limits, the object stops and reverses its direction of travel, thus its velocityat these two points is zero. While passing through the neutral or position of rest, the velocity is at its maximum. Since, the velocity is continually changing with respect to time, the peak or maximum velocity is always measured and commonly expressed in mm-per-second peak. When expressing the vibration characteristic in terms of velocity, both the displacement and frequency are considered. Since, the vibrating object must reverse course at the peak displacements, this is where the maximum acceleration occurs. Like velocity, acceleration is constantly changing, and the peak acceleration is usually measured. Displacement measurements can be important, especially in low frequency vibration son machines that have brittle components. That is, the stress that is applied issufficient to snap the component. Many machines have cast iron frames or cases thatare relatively brittle and are subject to failure from a single large stress. Acceleration measurements are also important in that they directly measure force. Excessive forcecan lead to improper lubrication in journal bearings, and result in failure. The dynamic force created by the vibration of a rotating member can directly causebearing failure. Generally a machine can withstand up to eight times its designed static load before bearing failure occurs. However, overloads as little as 10% cancause damage over an extended period of time. Although this seems insignificant, itcan be shown that small unbalances can easily create sufficient dynamic forces tooverload the bearings.

The International Standards Organization (ISO), who establishes internationally acceptable units for measurement of machinery vibration, suggested the velocity –root mean square (rms) as the standard unit of measurement. This was decided in anattempt to derive criteria that would determine an effective value for the varying function of velocity. *Velocity* – rms tends to provide the energy content in thevibration signal, whereas the velocity peak correlated better with the intensity of vibration. Higher velocity – rms is generally more damaging than a similar magnitude of velocity peak. The crest factor of a waveform is the ratio of the peak value of the waveform to the rms value of the waveform. It is also sometimes called the 'peak-to-rmsratio'. The crest factor of a sine wave is 1.414, i.e. the peak value is 1.414 times the rms value. The crest factor is one of the important features that can be used totrend machine condition. In discussing vibration velocity, it was pointed out that the velocity of the mass approaches zero at extreme limits of travel. Each time it comes toa stop at the limit of travel, it must accelerate to increase velocity to travel to theopposite limit. Acceleration is defined as the rate of change in velocity. Referring tothe spring-mass body, acceleration of the mass is at a maximum at the extreme limitof travel where velocity of the mass is zero. As the velocity approaches a maximumvalue, the acceleration drops to zero and again continues to rise to its maximum value at the other extreme limit of travel.

Significance of Dynamic parameters:

The displacement, velocity and acceleration characteristics of vibration are measuredto determine the severity of the vibration and these are often referred to as the ‘amplitude’ of the vibration. In terms of the operation of the machine, the vibration amplitude is the first indicator to indicate how good or bad the condition of themachine may be. Generally, greater vibration amplitudes correspond to higher levelsof machinery defects. The relationship between acceleration, velocity and displacement with respect to vibration amplitude and machinery health redefines the measurement and data analysis techniques that should be used. Motion below 10 Hz(600 cpm) produces very little vibration in terms of acceleration, moderate vibrationin terms of velocity and relatively large vibrations in terms of displacement. Hence, displacement is used in this range. In the high frequency range, acceleration values yield more significant values than velocity or displacement. Hence, for frequencies over 1000 Hz (60 kcpm) or 1500 Hz (90 kcpm), the preferred measurement unit for vibration is acceleration. It is generally accepted that between 10 Hz (600 cpm) and1000 Hz (60 kcpm) velocity gives a good indication of the severity of vibration, andabove 1000 Hz (60 kcpm), acceleration is the only good indicator. Since, the majority of general rotating machinery (and their defects) operates in the 10–1000 Hz range, velocity is commonly used for vibration measurement and analysis. In recent time,there is a concerted effort to utilize vibration monitoring in an extended role, mainlyin what is now commonly called predictive maintenance, which is an extension and/orreplacement of traditional preventive maintenance. [Scheffer&Girdher]An additional benefit of a model-based diagnostic approach is the ability to combine measured vibration signals with vibration computer model outputs to make real-time determinations of rotor vibration signals at locations where no sensors are installed. Typically, vibration sensors are installed at or near the bearings where sensor accessto the rotor and survivability of sensors dictate. However, midspan locations betweenthe bearings are where operators would most like to measure vibration levels butcannot because of inaccessibility and the hostile environment for vibration sensors. Thus, the model-based approach provides “virtual sensors” at inaccessible rotor locations.

Measured vibration using sensors:

The nature of sound and vibrations to be measured can vary widely. Sound can be“noisy” (roar or hiss-like), like that from a heavily trafficked highway, while vibrations of a machine are often dominated by the rotational frequency and its multiples. A machine under constant loading gives off a stationary noise, while the noise at an airport tends to be intermittent. Moreover, the purpose of measurements varies. The commonly monitored vibration signals are displacement, velocity, and acceleration. The basic operational principles of each of these are presented in this section. The measurement systems that are marketed today are primarily digital, i.e.,sound pressure and vibrations are converted into digital values for later treatment inmore or less advanced signal processors. While digital technology offers ever more sophisticated possibilities, measurement systems are nevertheless often adapted to beable to compare measurement results with those obtained in the past using analog technology. Digital measurement systems have a more complicated structure than analog ones. The types of transducers that are most commonly used in vibroacoustics are microphones to measure sound pressure, accelerometers to measure accelerations ofsolid structures, and force transducers to measure forces on solid structures. The principles behind force transducers are not described here, but are very similar tothose for accelerometers.

A number of characteristics are common to all types of transducers:

Sensitivity: Indicates the ratio of electrical output to mechanical input. Example: A microphone’s sensitivity is given in mV/Pa.

Frequency band: Indicates the upper and lower frequency limits, between which the transducer sensitivity varies within a given (small) tolerance range.

The accelerometer load cell is usually a piezoelectric crystal and thus registers only compressive loads, necessitating a preload spring to keep it in compression. However, the piezoelectric crystal is inherently quite stiff in comparison to the preload spring. Therefore, the load cell essentially registers “all” the dynamic force required to accelerate the internal mass.

Velocity Transducers: The velocity pickup is a very popular transducer or sensor for monitoring the vibration of rotating machinery. This type of vibration transducer installs easily on machines, and generally costs less than other sensors. For these two reasons, this typeof transducer is ideal for general purpose machine applications. Velocity pickups havebeen used as vibration transducers on rotating machines for a very long time, and theyare still utilized for a variety of applications today. Velocity pickups are available inmany different physical configurations and output sensitivities. When a coil of wire ismoved through a magnetic field, a voltage is induced across the end wires of the coil.The induced voltage is caused by the transferring of energy from the flux field of themagnet to the wire coil. As the coil is forced through the magnetic field by vibratory motion, a voltage signal representing the vibration is produced. The velocity pickup isa self-generating sensor requiring no external devices to produce a vibration signal as shown. This type of sensor is made up of three components: a permanent magnet, a coil of wire, and spring supports for the coil of wire. The pickup is filled with an oil to dampen the spring action. Due to gravity forces, velocity transducers are manufactured differently for horizontal or vertical axis mounting. With this in mind, the velocity

sensor will have a sensitive axis that must be considered when applying these sensors to rotating machinery. Velocity sensors are also susceptible to cross axis vibration, which if great enough may damage a velocity sensor. The higher output sensitivity is useful in situations where induced electrical noise is a problem. The larger signal for a given vibration level will be less influenced by the noise level.

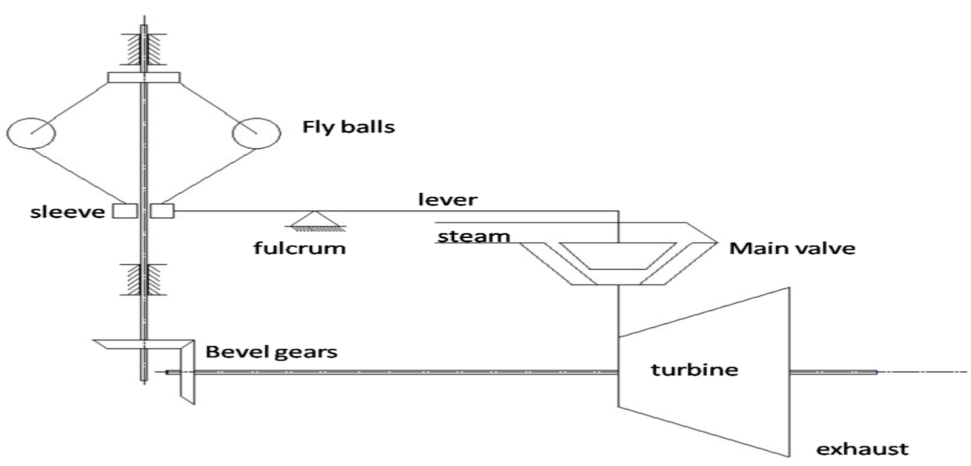
TURBINE MONOTORING AND CONTROL

Steam turbine governing is the procedure of controlling the flow rate of steam to a steam turbine so as to maintain its speed of rotation as constant. The variation in load during the operation of a steam turbine can have a significant impact on its performance. In a practical situation the load frequently varies from the designed or economic load and thus there always exists a considerable deviation from the desired performance of the turbine. The primary objective in the steam turbine operation is to maintain a constant speed of rotation irrespective of the varying load. This can be achieved by means of governing in a steam turbine. There are many types of governors.

Steam Turbine Governing is the procedure of monitoring and controlling the flow rate of steam into the turbine with the objective of maintaining its speed of rotation as constant. The flow rate of steam is monitored and controlled by interposing valves between the boiler and the turbine. Depending upon the particular method adopted for control of steam flow rate, different types of governing methods are being practiced. The principal methods used for governing are described below.

Throttle Governing

In throttle governing the pressure of steam is reduced at the turbine entry thereby decreasing the availability of energy. In this method steam is passed through a restricted passage thereby reducing its pressure across the governing valve. The flow rate is controlled using a partially opened steam control valve. The reduction in pressure leads to a throttling process in which the enthalpy of steam remains constant.



Throttle governing – Small turbines

Low initial cost and simple mechanism makes throttle governing the most apt method for small steam turbines. The mechanism is illustrated in figure. The valve is actuated by using a centrifugal governor which consists of flying balls attached to the arm of the sleeve. A geared mechanism connects the turbine shaft to the rotating shaft on which the sleeve reciprocates axially. With a reduction in the load the turbine shaft speed increases and brings about the movement of the flying balls away from the sleeve axis. This results in an axial movement of the sleeve followed by the activation of a lever, which in turn actuates the main stop valve to a partially opened position to control the flow rate.

Throttle governing – Big turbines

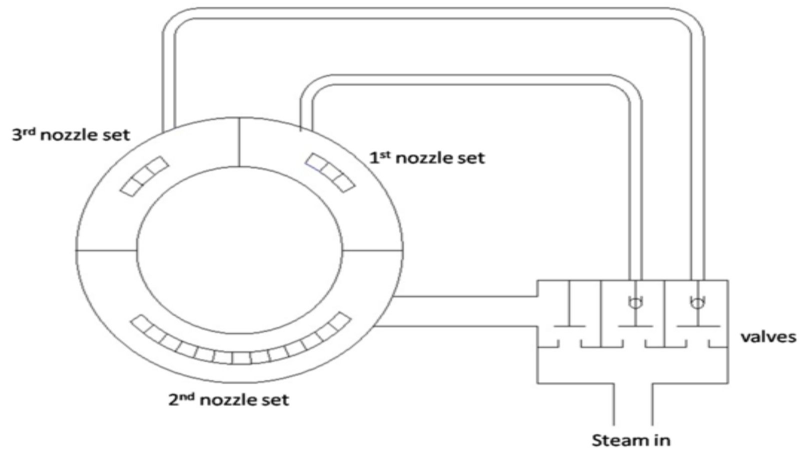
In larger steam turbines an oil operated servo mechanism is used in order to enhance the lever sensitivity. The use of a relay system magnifies the small deflections of the lever connected to the governor sleeve. The differential lever is connected at both the ends to the governor sleeve and the throttle valve spindle respectively. The pilot valves spindle is also connected to the same lever at some intermediate position. Both the pilot valves cover one port each in the oil chamber. The outlets of the oil chamber are connected to an oil drain tank through pipes. The decrease in load during operation of the turbine will bring about increase in the shaft speed thereby lifting the governor sleeve. Deflection occurs in the lever and due to this the pilot valve spindle raises up opening the upper port for oil entry and lower port for oil exit. Pressurized oil from the oil tank enters the cylinder and pushes the relay piston downwards. As the relay piston moves the throttle valve spindle attached to it also descends and partially closes the valve. Thus the steam flow rates can be controlled. When the load on the turbine increases the deflections in the lever are such that the lower port is opened for oil entry and upper port for oil exit. The relay piston moves upwards and the throttle valve spindle ascend upwards opening the valve. The variation of the steam consumption rate $\dot{m}$ (kg/h) with the turbine load during throttle governing is linear and is given by the “willan’s line”.

The equation for the willan’s line is given by:

$$\dot{m} = aL + C$$

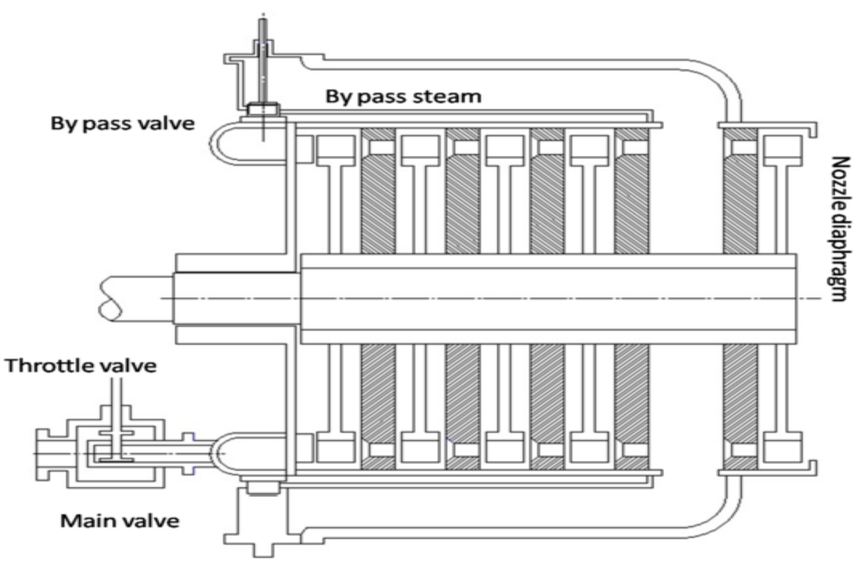
Where ***a*** is the **steam rate** in **kg/kWh**, '***L'*** is the load on turbine in ***KW*** and ***C*** is no load steam consumption.

Nozzle Governing: The flow rate of steam is regulated by opening and shutting of sets of nozzles rather than regulating its pressure. In this method groups of two, three or more nozzles form a set and each set is controlled by a separate valve. The actuation of individual valve closes the corresponding set of nozzle thereby controlling the flow rate. In actual turbine, nozzle governing is applied only to the first stage whereas the subsequent stages remain unaffected. Since no regulation to the pressure is applied, the advantage of this method lies in the exploitation of full boiler pressure and temperature. Figure shows themechanism of nozzle governing applied to steam turbines. As shown in the figure the three sets of nozzles are controlled by means of three separate valves.



Bypass Governing

Occasionally the turbine is overloaded for short durations. During such operation, bypass valves are opened and fresh steam is introduced into the later stages of the turbine. This generates more energy to satisfy the increased load. The schematic of bypass governing is as shown in figure



Combination Governing

Combination governing employs usage of any two of the above mentioned methods of governing. Generally bypass and nozzle governing are used simultaneously to match the load on turbine.

Emergency Turbine Governing

Every steam turbine is also provided with emergency governors which come into action under the following condition.

- When the mechanical speed of shaft increases beyond 110%.
- Balancing of the turbine is disturbed.
- Failure of the lubrication system.
- Vacuum in the condenser is quite less or supply of coolant to the condenser is inadequate.

Speed regulation

The control of a turbine with a governor is essential, as turbines need to be run up slowly to prevent damage and some applications (such as the generation of alternating current electricity) require precise speed control. Uncontrolled acceleration of the turbine rotor can lead to an overspeed trip, which causes the governor and throttle valves that control the flow of steam to the turbine to close. If these valves fail then the turbine may continue accelerating until it breaks apart, often catastrophically. Turbines are expensive to make, requiring precision manufacture and special quality materials.

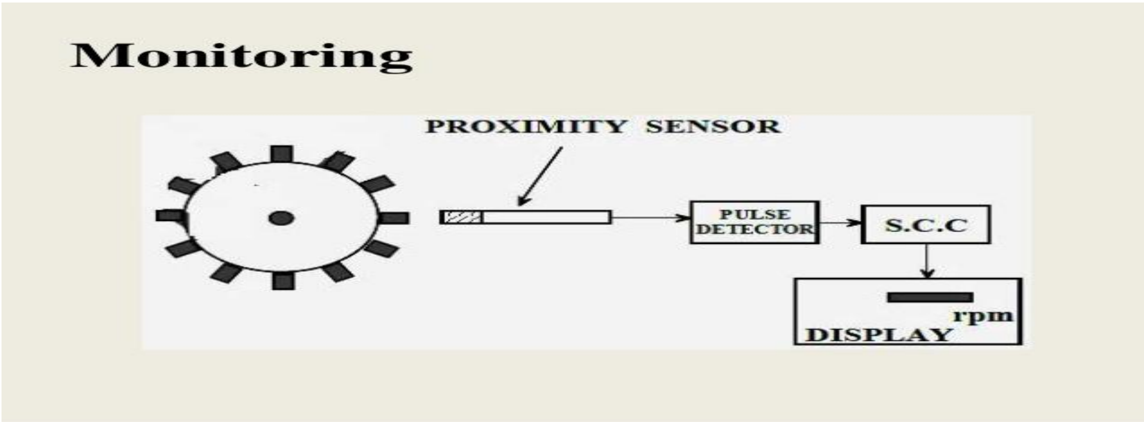
During normal operation in synchronization with the electricity network, power plants are governed with a five percent droop speed control. This means the full load speed is 100% and the no-load speed is 105%. This is required for the stable operation of the network without hunting and drop-outs of power plants. Normally the changes in speed are minor. Adjustments in power output are made by slowly raising the droop curve by increasing the spring pressure on a centrifugal governor. Generally this is a basic system requirement for all power plants because the older and newer plants have to be compatible in response to the instantaneous changes in frequency without depending on outside communication.

Turbine speed

- Seed is defined as distance travelled or revolution per unit time of a system.
- Frequency of power signal varies with the speed of turbine hence speed of turbine is monitored.
- The speed of the turbine is measured by means of optical measurement method.The arrangement is as shown in the figure and a circular plate with a hole in a regular

intervals at its circumference is attached to the rotating part of the turbine and light can pass through the holes.

- The plate with holes is illuminated by means of light source and light is detected by means of proximity sensor placed and the pulses are generated when light is detected and through the moving plate with holes.
- From the pulses generated per second the speed of the turbine is calculated.



Turbine vibration

Need

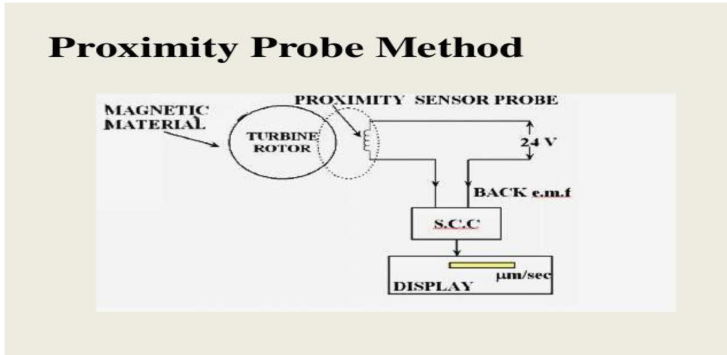
- The unwanted acceleration of fixed unit over a fixed boundary is defined as vibration.
- Vibration in turbine reduces the efficiency of the turbine and causes damage to the plates of the turbine.

Monitoring

The vibration in turbine can be measured by means of two methods.

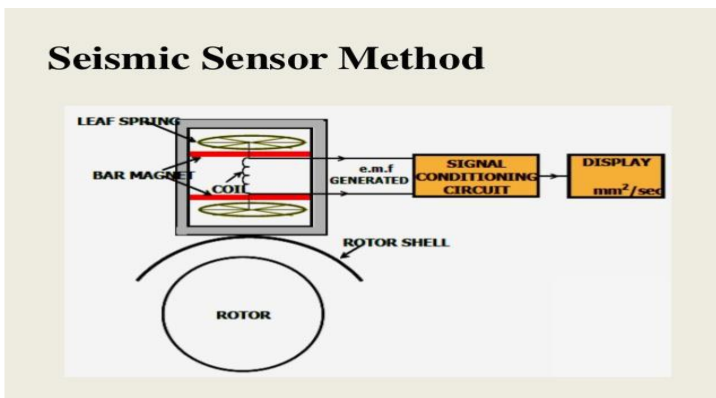
1. Non – contact measurement method (Proximity probe method).

2. Direct contact method (Seismic sensor method).



A non – contact measurement method:

- The proximity probe energized by 24 V is placed on the boundary such that it is closed to the turbine boundary and the back emf of the probe is monitored.
- If there is vibration the boundaries of the turbine get changed, this reflects the change in the back emf measured.
- From the back emf changes vibration of the turbine is measured.



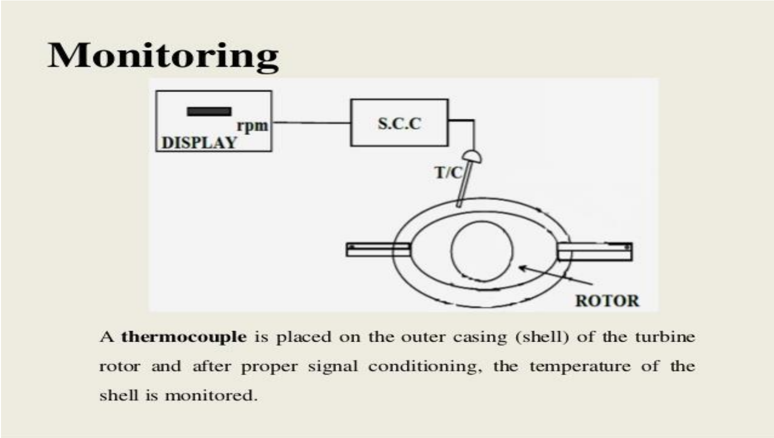
A direct contact measurement type method:

- The device works according to the concept of generating emf by moving a conductor in a magnetic field.
- The device is place over the covering of the turbine. Where the turbine is under vibration the leaf spring jumps, due to this emf is generated in the coil.
- The emf generated is proportional to the vibration, the emf generated in coil is transferred to the bridge connected to the coil and amplified and then displayed in terms of units of vibration.

SHELL TEMPERATURE

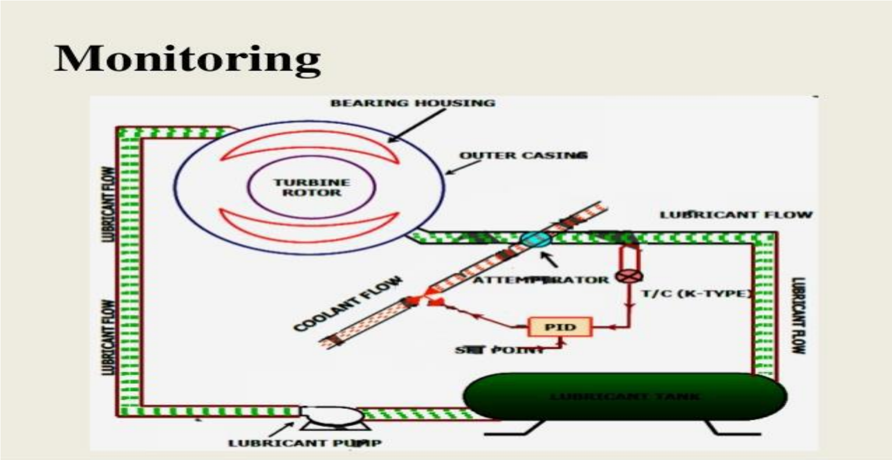
- Shell also known as casing is the principal stationary element.

- It surrounds the rotor and holds, internally, any nozzles, blades and diaphragms that may be necessary to control the path and physical state of expanding steam.
- This casing is normally thermally insulated from the outside to prevent radiation losses. For this purpose
- Shell temperature is monitored at different locations.



LUBRICATION OIL TEMPERATURE

- The cohesiveness of lubrication is inversely proportional to its temperature.
- The less cohesive lubricant will not lubricate effectively, hence the temperature of the lubricant is kept under control.



- The temperature of the lubricant is measured after the lubrication process by means of thermocouple and compared with the set point in the controller.
- The controller gives command accordingly to control the cooling water sprayed over the lubricant to reduce the lubricant temperature.