

Module 1

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1.0 ENERGY SCENARIO

1.1 Introduction

Fossil fuels such as oil, natural gas, and coal have been the world's primary energy source for several decades. Currently, conventional fossil fuels supply about 85% of the global primary energy consumption for industrial, transportation, commercial and residential uses. Total primary energy consumption comprising commercially-traded fuels including renewable energy was 13511.2 million tonnes oil equivalent (MTOE) in 2017. The world primary energy consumption by fuel type/source is shown in Figure 1.1.

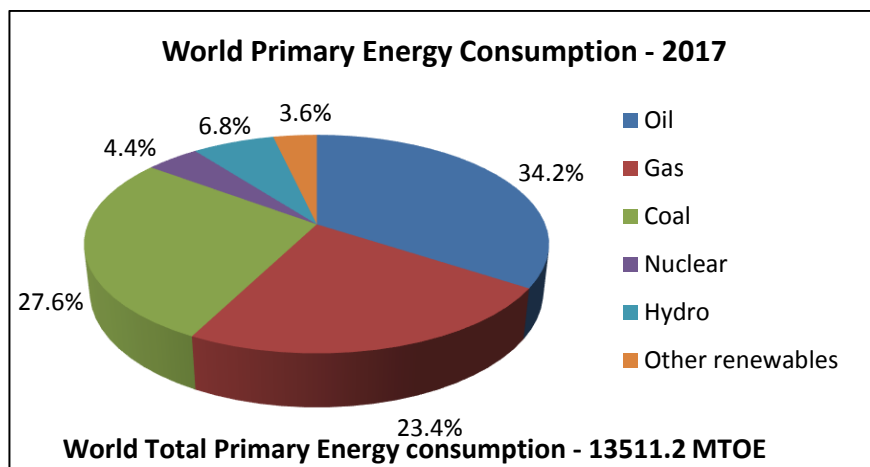


Figure 1.1: Breakup of World Primary Energy Consumption by Fuel / Source

Source : BP Statistical Review of World Energy 2018

The world is facing the reality that fossil fuels will be exhausted soon as the global consumption rate is outpacing the discovery and exploitation of new reserves, and that the global environment is worsening due to increasing greenhouse gas (GHG) emissions caused by fossil fuels. The world primary energy consumption trend is shown in Figure 1.2.

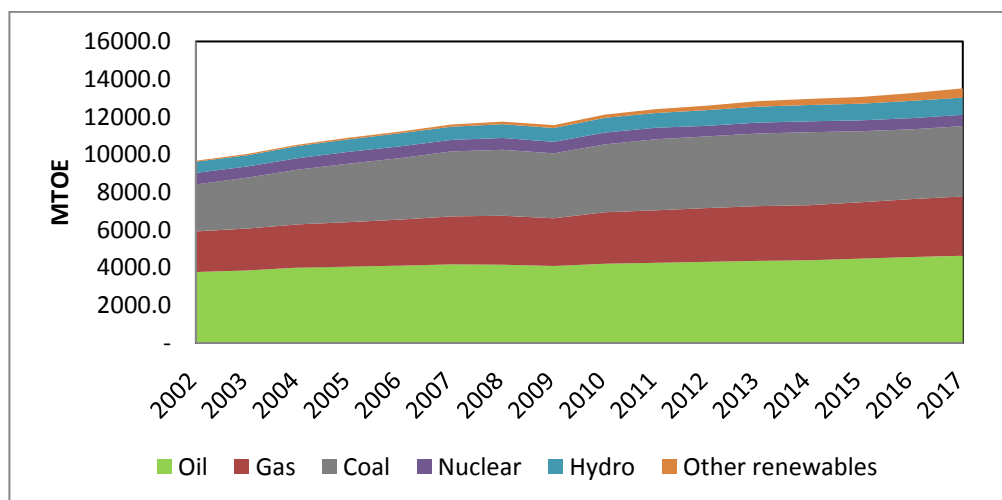


Figure 1.2: World Primary Energy Consumption Trend
Source: BP Statistical Review of World Energy 2018

Among the fossil fuels, natural gas share of the primary energy mix has seen the highest growth rate internationally. Unconventional gas, shale and coal bed methane (CBM) are also available as LNG in the regional gas markets. Natural gas has the potential to play an important role in the transition to a cleaner, more affordable and secure energy future. Natural Gas offers a much cleaner alternative to coal for power generation and produces only around half of the carbon dioxide (CO₂) emissions of coal when burned to generate power.

Bangladesh Primary energy consumption has been increasing steadily, at around 8% per year. Its primary energy consumption was 33 million tonnes oil equivalent in 2017, which is about 0.2% of the world's consumption. The energy consumption is growing at the rate of about 2% annually and its economy faces significant challenges in meeting energy needs in the coming decades. The increasing energy needs coupled with declining domestic energy production mainly natural gas has meant that bulk of energy will have to be met by increasing exports. Bangladesh primary energy consumption by energy source/type is shown in the Figure 1.3.

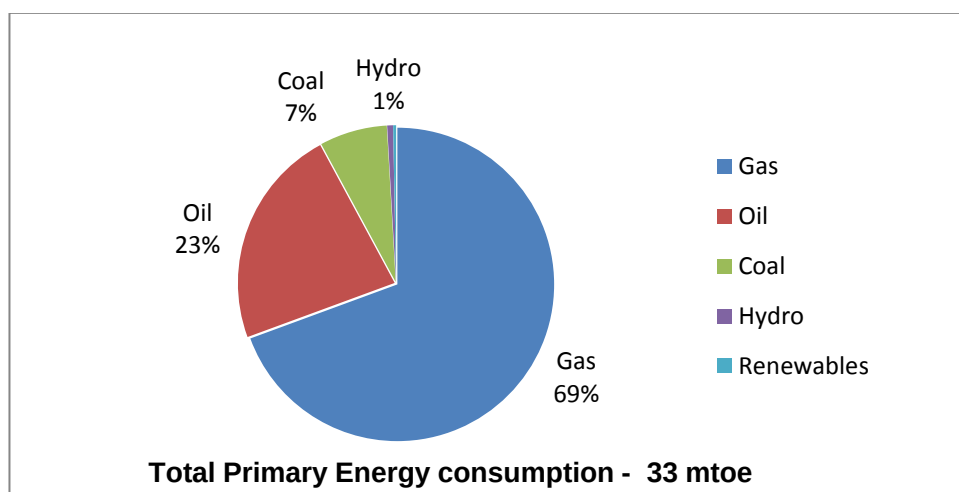


Figure 1.3: Breakup of Bangladesh Primary Energy Consumption by Fuel/Source

Source: BP Statistical Review of World Energy 2018

As seen from the graph, Gas (69%) and petroleum (23%) are the main sources of primary energy to meet the energy demand of Bangladesh.

The Bangladesh's growth of primary energy consumption over the last decade is illustrated in Figure 1.4.

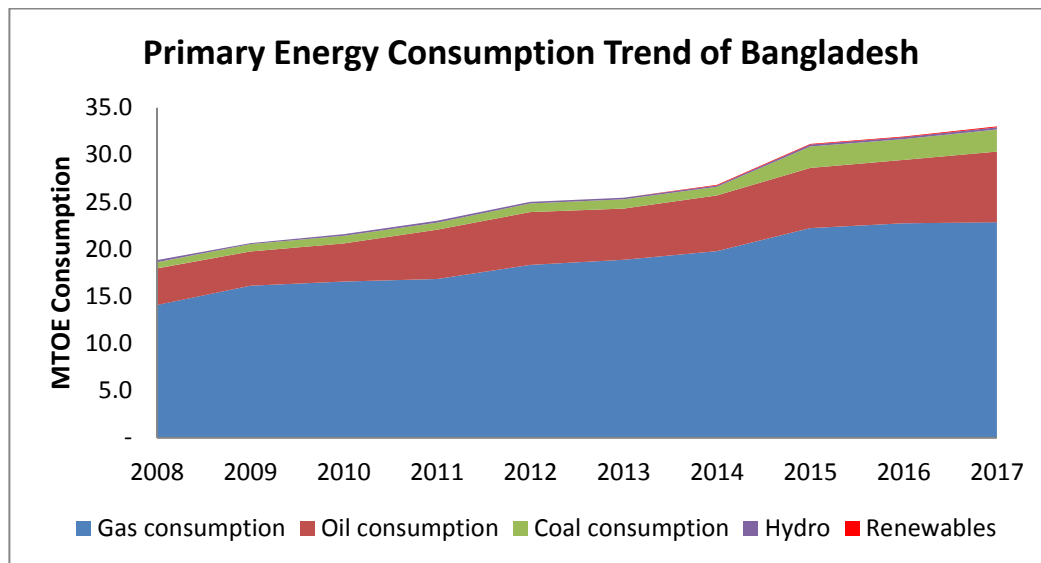


Figure 1.4: Primary Energy Consumption Trend of Bangladesh

Source: BP Statistical Review of World Energy 2018

1.2 Natural Gas

Natural gas is the major fuel in Bangladesh. Natural gas produced in Bangladesh contains 95-99% methane and all others are hydrocarbon components. It contains almost no other impurities such as hydrogen sulphide, carbon dioxide and/or nitrogen. To date, 26 gas fields have been discovered in Bangladesh and natural gas reserve is estimated at 0.2 trillion cubic meters which is about 0.1% of the world reserves. Reserve/Production (R/P) ratio is estimated at only 6.7 years as of end of 2017.

Around three-fourth of the total primary energy consumption comes from natural gas. Bangladesh share of world consumption is only 0.7% and almost all the natural gas domestic consumption (26.6 Billion cubic metres) is met by domestic production (2017). The shares of industrial and residential sector are 56.3% and 29.3% respectively. The distribution of gas consumption (excluding grid and captive power) is shown in the Table 1.1.

Table 1.1: Gas Consumption (Excluding Grid and Captive Power)

	Industry	Transport	Residence	Commercial	Agriculture
Gas	56.3%	11.6%	29.3%	2.6%	0.2%

Source: Gas MIS of Petrobangla, 2013-2014, Petroleum BPC, 2012-2013

Domestic gas supply has reached peak production and it is expected to decline and the demand will exceed the supply. This means the demand and supply gas must be filled by LNG imports.

Bangladesh's LPG demand is expected to grow drastically as an alternative for households' cooking fuel (currently domestic natural gas) and transportation fuel. Government wants to promote LPG as an alternative to conventional biomass as LPG is widely available, highly energy efficient, and less CO₂ and air-polluting particles emission than combustion of conventional solid biomass and less risk of deforestation by overexploitation of forest resources. The current price of LPG is two to three times higher than that of the piped gas supply. To meet the increasing demand, LNG terminals are being setup. Currently there are four import terminals and seven LPG private operators in Bangladesh, who deals with LPG import, shipping and distribution. Also the government has guaranteed to issue licenses to more new private operators

GTCL (Gas Transmission Company Limited) was setup with the objectives of centralized operation and maintenance of national grid, and expanding the system as required, ensuring balanced supply and usage of natural gas in all regions of the country. GTCL transports almost 70 % of gas produced to various regions of Bangladesh.

1.3 Oil

Oil remains the world's leading energy source, accounting for about 34% of total global energy consumption in 2017. In recent years, supply of unconventional oil (shale oil, oil sands, natural gas liquid, liquid fuels derived from coal and gas) along with increased crude production both from mature oil fields has supported oil demand

Bangladesh share of world oil consumption is 0.2% which was about 146 thousands of barrels per day (2017). Bangladesh produces a small amount of condensates (about 7,800 barrels per day as of December 2014), from natural gas fields. Condensates are fractionated to petroleum products, such as liquefied petroleum gas (LPG) and motor gasoline and are marketed in the domestic oil market. The domestic condensate supplies only about 5% of the total domestic oil demand in Bangladesh, and most of the oil demand is met with import from abroad.

The growing mobility and increasing demands for passenger and freight movement has increased the consumption of petroleum products in the road transport sector. The transport sector has the largest share (59.8%) in petroleum (oil) consumption, followed by agriculture (25.8%) and residential sectors (9.0% in the form of kerosene oil). The distribution of oil consumption (excluding grid and captive power) is shown in Table 1.2.

Table 1.2: Petroleum Consumption (Excluding Grid and Captive Power)

	Industry	Transport	Residence	Commercial	Agriculture
Oil	4.9%	59.8%	9.0%	0.5%	25.8%

Source: Gas MIS of Petrobangla, 2013-2014, Petroleum BPC, 2012-2013

Bangladesh's current oil annual demand is around 5 million tons, and the self-sufficiency rate is only 5%. However, Bangladesh expects continuous economic development, and the industry sector and transport sector demand will lead drastic oil demand growth: 6 times higher in 2041 than in 2016 (average growth rate 7.4% p.a.), even under the "Energy Efficient and Conservation Scenario".

The country has only one refinery in Chittagong; but its refining capacity is not sufficient to meet the country's total oil demand, and the country imports oil products for the remaining demand. Oil refining throughput was 28 thousand barrels daily as against capacity of 43 thousand barrels daily (2017).

Bangladesh has several plans to increase capacity of existing refineries or newly develop oil refineries.

1.4 Coal

Globally, coal is the predominant of the three major fossil fuels and most widely distributed with reserves in over 100 countries. World proved coal reserves are currently sufficient to meet 136 years of global production, which means that Reserve/Production (R/P) ratio is much higher than that of oil and gas.

In Bangladesh, coal is generally characterized as having low ash content and low sulfur content that are in favour of the environment. It is basically bituminous coal. Another grade of coal, which is classified into coking coal for iron production whose commodity value is very high in the market, is also available. Small amounts of coking coal are also produced in Bangladesh, which are being exported and the associated middling is being supplied to a domestic coal fired power station.

1.5 Nuclear Power

The development of nuclear power is today concentrated in a relatively small group of countries namely China, Korea, India and Russia. As of January 2015, the total identified resources of uranium are considered sufficient for over 100 years' of supply based on current requirements.

The nuclear is increasingly seen as a means to add large scale base load power generation while limiting the amount of GHG emissions. The low share of fuel cost in total generating costs makes nuclear the lowest-cost base load electricity supply option. Uranium costs

account for only about 5% of total generating costs and thus protect plant operators against fuel price volatility.

Bangladesh is introducing nuclear energy as a safe, environmentally friendly and economically viable source of electricity generation. The plant in Rooppur, 160 kilometres north-west of Dhaka, will consist of two units, with a combined power capacity of 2400 MW(e). It is being built by a subsidiary of Russia's State Atomic Energy Corporation ROSATOM. The first unit is scheduled to come online in 2023 and the second in 2024.

1.6 Renewable Energy

Bangladesh has currently 432 MW installed renewable energy capacity which only about 2.89% of the total share. The Government has plans to augment capacity to be about 21,600 MW (policy target of 10% renewable) by 2020. Installed renewable energy capacity (as of September, 2017) is given in Table 1.3.

Table 1.3: Installed Renewable Energy Capacity in MW (as of September, 2017)

S.L.	Technology	Off-Grid	On-Grid	Total
1	Solar PV	202.74 MW	14.01 MW	216.75 MW
2	Wind	2 MW	0.9 MW	2.9 MW
3	Hydro	-	230 MW	230 MW
4	Biogas to Electricity	0.68 MW	-	0.68 MW
5	Biomass to Electricity	0.4 MW		0.4 MW
Total		205.82 MW	244.91 MW	450.73 MW

Source: SREDA

Solar PV technology has low energy-intensity and requires large area land. A major obstacle to deploy large-scale solar PV is the availability of land. Setting up 30 MW solar plant for example would require approximately 60 ha land. Bangladesh government has already stipulated a policy prohibiting farmland use for private solar projects, which limits the solar park potential to 1,400 MW. The break-up of solar power (as of September, 2017) is given in the Table 1.4.

Table 1.4: Solar Power

S.L.	Technology	Capacity
1	Solar Home System (4.4 Million Nos)	179.27 MW
2	Solar Irrigation (671 Nos)	6.63 MW
3	Roof Top (stand alone)	14.65 MW

4	Roof Top (grid-tied)	11.03 MW
5	Solar Mini Grid	2.19 MW
Total		216.75 MW

*Updated September 2017

The development of wind power generation is limited. Wind potential is estimated at 624 MW (SREDA) and wind power generation is limited to two points (Muhuri Dam 900 kW and Kutubdia 1000 kW).

Renewable Energy contribution in power mix is illustrated in the following chart.

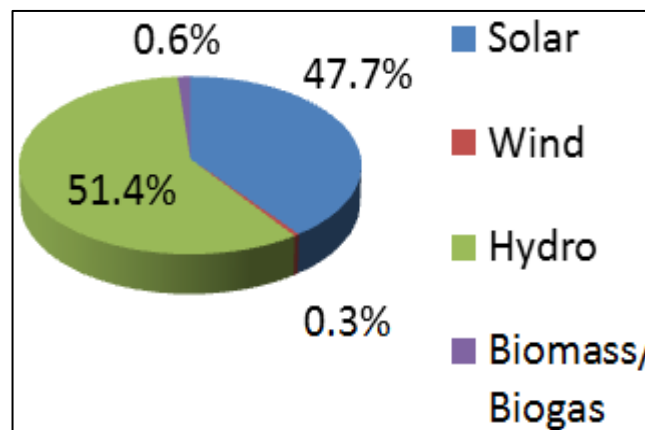


Figure 1.5: Renewable Energy Contribution in power mix

1.7 Electricity Supply Trend

Average electricity demand is growing at over 10% per year, owing to rapid economic growth, industrialization, expansion in grid connection and inclusion of new electrical devices and appliances.

Bangladesh's share of gas-fired capacity accounted for about 58% of total installed electricity capacity which reached 10.14 Giga Watts (GW) by 2018. In recent years, diesel or fuel oil based units have come into operation. According to the government of Bangladesh, about 62% of the population has access to electricity. The peak load deficit which resulted in regular load shedding during the peak hours were however minimized by substantial increase in generation along with infrastructure development in recent years.

The government seeks to replace older, inefficient units and increase electricity generation capacity to match the electrification rates of other developing countries.

Bangladesh plans to more than double power generation capacity to 24 GW by 2021, primarily through the use of coal and natural gas.

Table 1.5 shows the present installed generation capacity by different sectors and figures 1.6 & 1.7 shows the installed capacity of power generation by fuel type and plant type. The present energy mix for electricity generation is dominated by natural gas followed by petroleum (HFO/HSD).

Table 1.5 : Present Installed Generation Capacity (MW) as on 28 October, 2018
 (Source: www.bpdb.gov.bd)

Public Sector	Installed Generation Capacity (MW)
BPDB	5266
APSCL	1444
EGCB	839
NWPGCL	1211
RPCL	77
BPDB-RPCL JV	149
Subtotal	8986 (52%)
Private Sector	
IPPs	5099
SIPPs (BPDB)	99
SIPPs (REB)	251
15 YR. Rental	169
3/5 YR. Rental	1576
Power Import	1160
Subtotal	8354 (48%)
TOTAL	17,340
Captive Power & Renewable Energy	2800 + 290
Grand Total	20,430 MW

BPDB: Bangladesh Power Development Board (BPDB)

APSCL: Ashuganj Power Station Company Limited

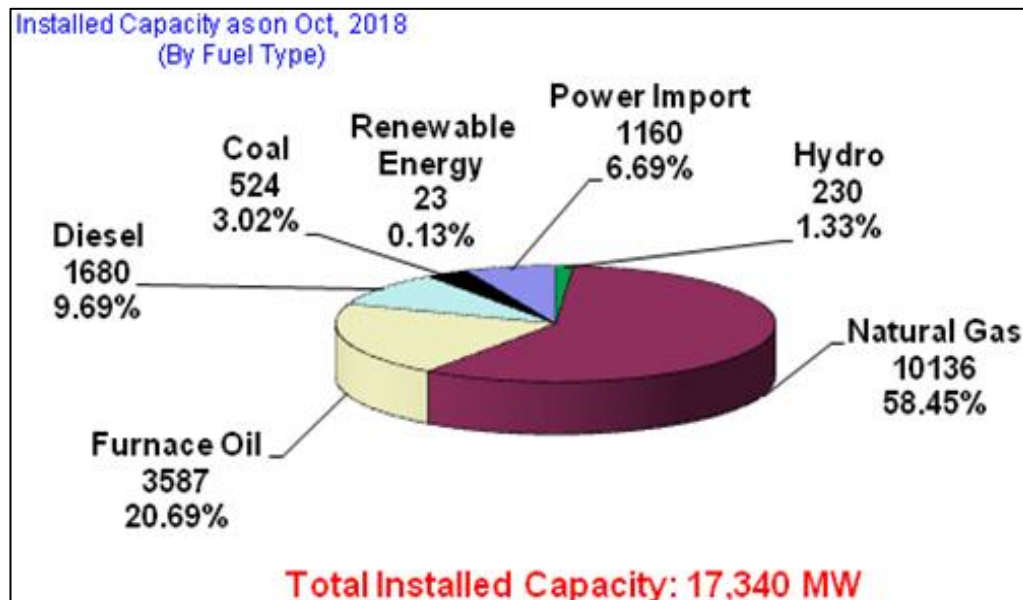
EGCB: Electricity Generation Company of Bangladesh

NWPGCL: Northwest Power Generation Company Limited

RPCL: Rural Power Company Limited

IPPs: Independent Power producers (IPP, SIPP & Rental)

The Bangladesh Power Development Board (BPDB) is responsible for the major portion of generation and distribution of electricity mainly in urban areas of the country. The Board is now under the Power Division of the Bangladesh Ministry of Power, Energy and Mineral Resources. The main fuel used for power generation in BPDB plants is indigenous natural gas. BPDB operations also include projects that utilize renewable power sources including offshore wind power generation. Out of 100% total installed generation, 52% is by the public sector power plants operated by BPDB & others and balance 48% by private sector as per 2018. Under the existing generation scenario of Bangladesh, Renewable Energy has a very small share to the total generation. The present Government is placing priority on developing Renewable Energy resources to improve energy security and to establish a sustainable energy regime alongside of conventional energy sources.



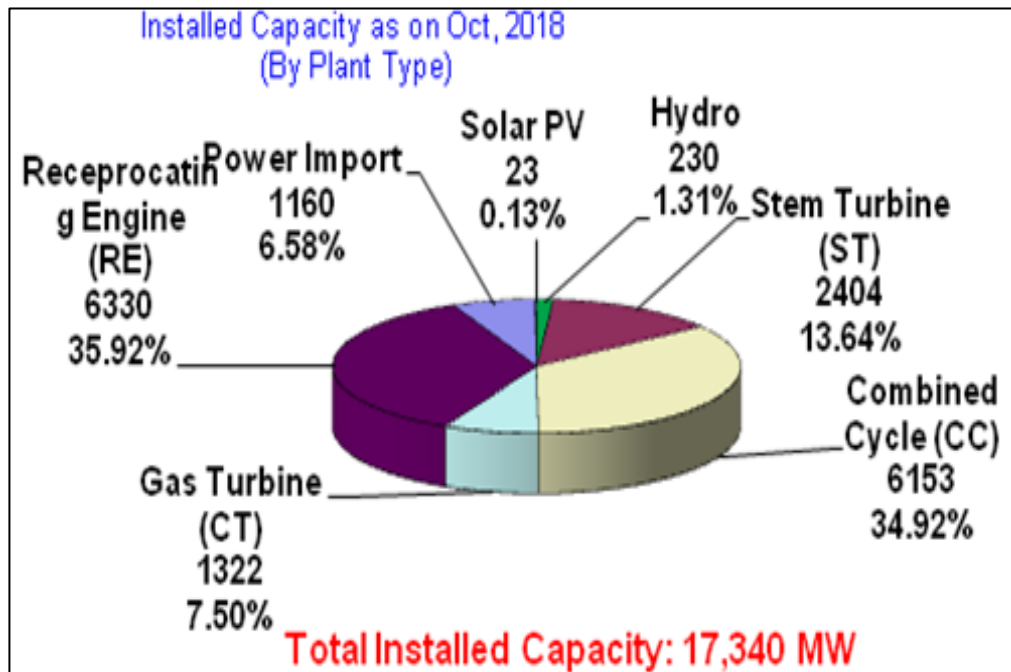


Figure 1.7: Installed Capacity by Plant Type

The power plants in the country are mostly gas-fired and with decline in gas supply projected from 2018 onwards, Bangladesh may not go for further gas fired power plants without sourcing LNG supply or discovering new gas reserve. Alternative sources of power generation through coal, oil, renewable and new energy sources (such as nuclear and hydro power generation) are being explored. The Government has drafted Power System Master Plan 2010 (PSMP) to improve and expand electricity supply.

1.8 Final Energy Consumption

Final energy consumption is dominated by domestic (50%) followed by industry (34%) and commercial (9%). The break-up is illustrated in the following Figure 1.8.

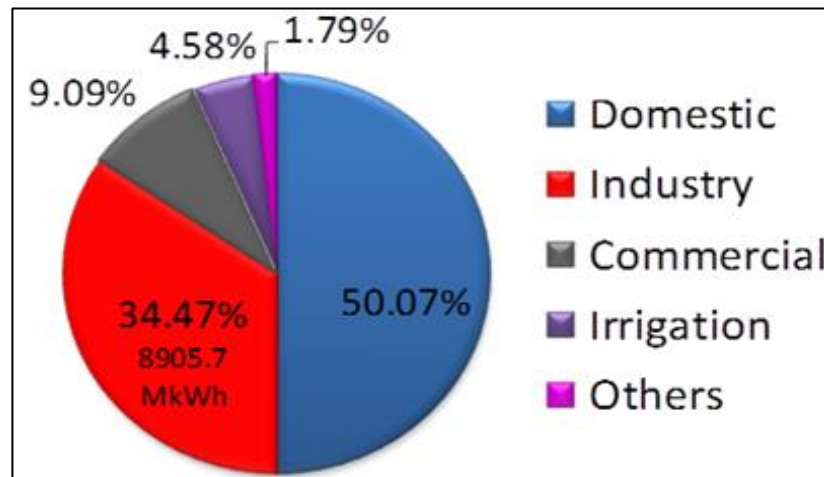
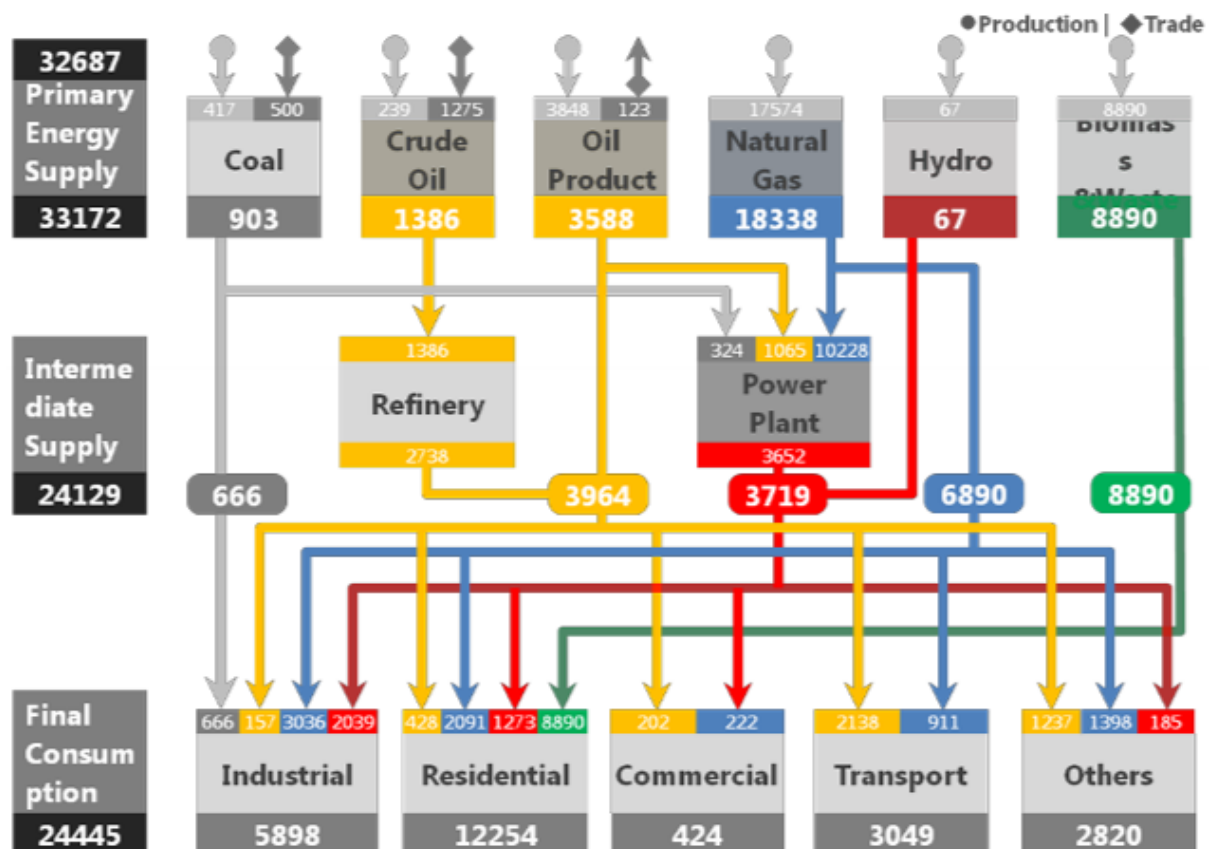


Figure 1.8: Final Energy Consumption

1.9 Energy Balance in Bangladesh

Figure 1.9 shows the energy balance of Bangladesh in 2012, based on the data from International Energy Agency (IEA). Primary energy supply of Bangladesh is 33,172 ktoe, of which 55% is dependent on domestic natural gas, followed by 27% of biomass & waste in rural area and 15% of imported oil. On the demand side, out of 24,445 ktoe final consumption, the industrial sector uses 24% and residential sector (excluding biomass & waste) 15%.



Source: Compiled by JICA Project Team based on IEA country statistics (2012 data)

Figure 1.9: Energy Balance in Bangladesh (2012)

1.10 Energy Efficiency and Conservation Program (EE&C)

Bangladesh has set following targets as part of INDC commitments:

1. 10% (2000 MW) of total Electricity Generation will be from RE by 2020
2. 15% & 20% reduction in Primary Energy Consumption per GDP by 2021 & 2030 respectively.

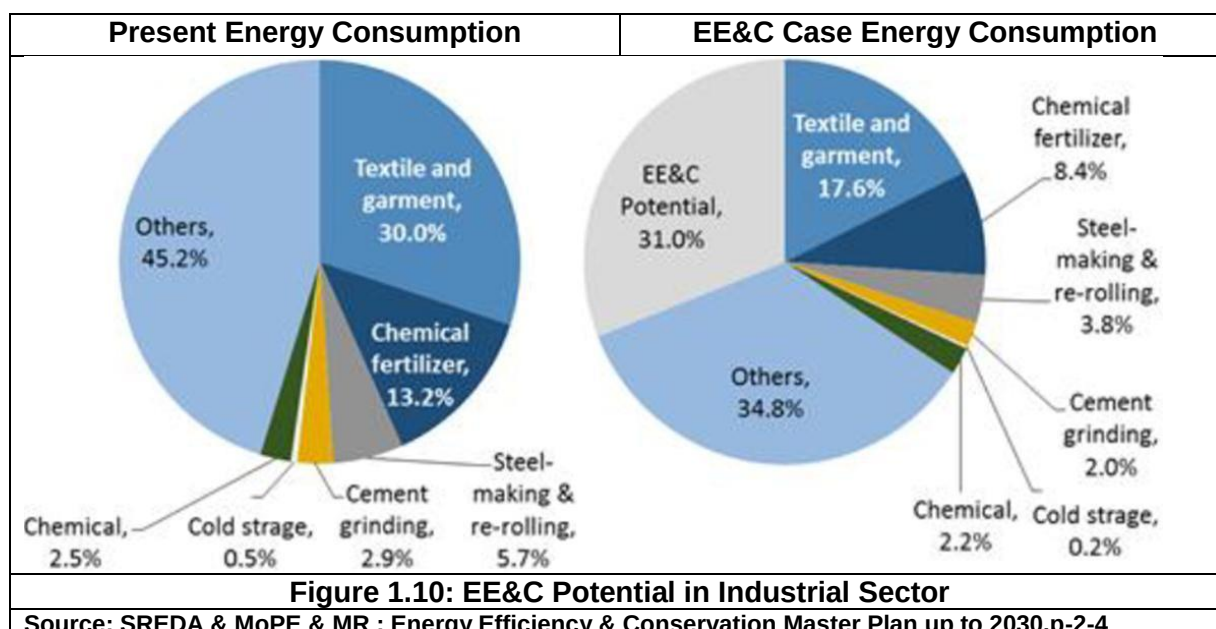
It is expected that in the EE&C scenario (20% energy efficiency improvement by 2030), the electricity demand by 2030 will result in avoided generation of 7 GW compared to the BAU case. This will also lead to reduce the import of primary fuel for power generation as well. EE&C potential in various sectors namely industrial,

EE&C Potential

EE&C potential is defined as an expected amount of energy reduction, gained by introducing more effective energy management, energy efficient equipment, insulation and solar energy nationwide. EE&C potentials by sector were estimated as follows.

Industrial Sector

Manufacturing industries are not efficient in energy use, because of the continuous usage of old/poorly-maintained machines and poor energy management. It is estimated that, through energy intensity comparison and actual on-site energy audits, the accumulating EE&C potential in industrial sub-sectors amount to around 21% of the entire industrial sector consumption. Considering the fact that about 50% of national primary energy is consumed in the industrial sector, the potential reduction due to various EE&C measures is estimated at about 10.5% of the total energy consumption (Figure 1.10).



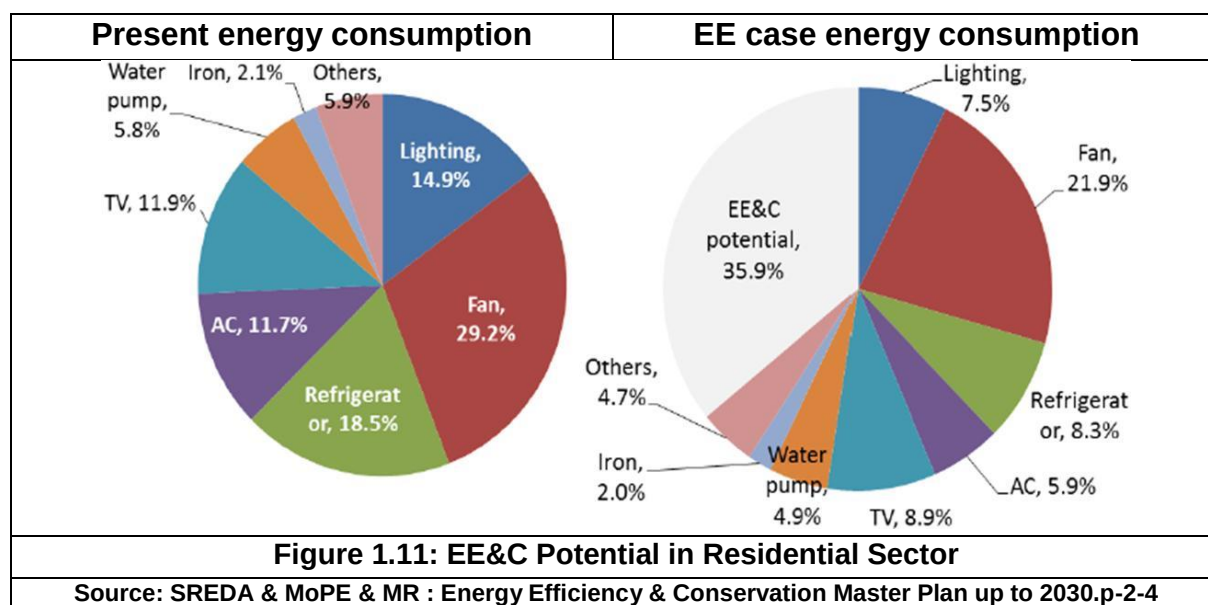
Gas use efficiency is one of the critical issues that need to be introduced. “Cheap gas” will not be available in the future and gas users need to enhance their efficiency to save the country’s indigenous gas resources. Both the Urea Manufacturing Sector and Power Sector are major gas users and have a significant impact on the overall gas consumption.

Urea is manufactured from natural gas. The world benchmark efficiency for Urea Manufacturing is 25mcf/ton, while average efficiency in Bangladesh was 44 mcf/ton as of 2014 FY, which is much higher than that of the international benchmark. If international benchmark is adopted in the country, 130 mmscfd of gas would be saved in manufacturing 2,375,000 tons in 2014 and this figure would translate into the power plant equivalent of 1000 MW.

Gas Consumption for the Power Sector (under BPDB) was 337.4 BCF in FY 2014 while Power Generation Capacity was 8,340 MW and Generated Power was 42,200 GWh. The current power generation efficiency is around 38%. If the efficiency can be raised to 45%, which is considered the international benchmark for a gas based power plant, Energy gas consumption will be reduced to 285 BCF, and the difference of 52 BCF can be said to be wasted. This is equivalent to 1,300 MW in power plant annual operation.

Residential Sector (Electric Home Appliances)

If all the existing home appliances in residences are to be replaced by higher efficiency products, huge energy reduction can be achieved. Considering the fact that about 30% of national primary energy is consumed in the residential sector, the potential reduction in energy consumption due to EE&C measures is estimated at almost 8.6% of the total energy consumption (Figure 1.11).



Commercial Sector (Buildings)

Electricity is the main mode of energy in commercial buildings and almost 50% of the total energy is consumed by ACs and 10-30% by lighting systems. It is expected that a simple replacement of ACs and lighting systems with high energy efficiency equipment and systems can save about 50% of total electricity consumptions in the commercial sector. EE&C potential for buildings is estimated at about 10%.

Agricultural Sector

Electricity (including captive power) is the main mode of energy in agricultural sector and the largest energy is used for irrigation pumps. EE&C potential for existing pumps is expected around 20%.

1.11 Targets and Action Plans

The various indicators to evaluate the improvement of future national energy efficiency are as follows:

- The actual reduction amount of energy consumption,
- Reduction ratio (value) for future BAU value,
- Energy consumption per capita and
- Energy consumption per Gross Domestic Product (GDP), etc.

Out of these indicators, energy consumption per GDP which considers both energy efficiency and national economic growth is the most appropriate for Bangladesh. In this EECMP, “**primary energy consumption per GDP**” is chosen as the indicator to set EE&C target and evaluate future national energy efficiency.

It is proposed to achieve EE&C targets in a phased manner through combination of regulatory measure and incentive mechanisms with nationwide action plans to reduce “primary energy consumption per GDP”. The targets for 2021 and 2030 are set at 15% and 20% reduction, compared with 2013 value. The various action plans for achieving targets are summarized in the following Table: 1.6.

Table: 1.6 Summary of EE&C programs in Action Plans

Program	Target	Methodology
Energy Management Program (EMP)	Large Industrial Energy Consumers	- Large energy consumer designation - Energy Manager, Certified Energy Auditor and Accredited Energy Auditor certification with qualification and examination system - Energy audit (mandatory/voluntary) - Energy consumption reporting (mandatory) - Benchmarking
EE Labeling Program (EELP)	Residential Consumers	- Label certification / Laboratory accreditation system - Standardization of EE measurement method and Star Label Rating criteria - Star Label Standardization (Unification) - Participation of manufactures, importers and retail shops (mandatory/voluntary) - MEPS (Minimum Energy Performance Standard)

		• Effective means to be developed to stop entry of below standard and energy inefficient products/items in the market.
EE&C Finance Incentive Program	Private Companies	• Low-interest loan for EE&C investment • Preferential taxation on high efficiency equipment/appliances and/or EE&C investment • Subsidy for EE&C investment • Other incentive mechanisms
Government's Own Initiatives	Government	• Green Purchase Program for Eco-friendly public procurement • Obtain ISO14001 and 50001 certification
Energy Consumption Data Collection	Government	• Energy consumption data by fuel • Energy consumption data by sector and sub-sector • Energy intensity data
Global Warming Countermeasure	All	• Formulation and quantification of national carbon market • Carbon abatement project as capacity development • Awareness raising

1.12 Policies relevant to Energy Efficiency

1. National Energy Policy
2. Action Plan for Energy Efficiency & Conservation, 2013
3. Renewable Energy Policy of Bangladesh, 2008
4. Energy Efficiency and Conservation Master Plan up to 2030
5. Energy Efficiency and Conservation Rules, 2016
6. Energy Audit Regulation, 2017



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Chapter 2

ENERGY MANAGEMENT AND AUDIT

2.1 Introduction

Energy such as electricity, oil, coal, and natural gas is being consumed in all facilities for its operations. If energy is not efficiently used and managed, it will increase operational and maintenance costs besides polluting the environment.

Energy management can be defined as:

“The judicious and effective use of energy to maximize profits (that is, minimize costs) and enhance competitive positions.”

Organisations that successfully manage energy have business processes to plan, monitor, and control energy use, just as they do for other corporate priorities, such as labour, materials, and other costs. For these organisations, energy management is “business as usual”.

Successful energy management need an effective strategy and involves all employees. Energy audit is the key to a systematic approach for decision making in the area of energy management.

An energy audit is an investigation of all facets of a facility’s historical and current energy use with an objective of identifying and quantifying areas of energy wastage in its activities. The outcome is the identification of viable and cost effective energy saving measures to reduce energy consumption per unit of product output thereby lowering the operating costs.

Energy audit serves as the ‘foundation’ on which successful energy management programme can be built in an organisation. Energy audit also provides a 'benchmark' for managing energy and planning a more effective use of energy throughout the facility.

2.2 Scope of Energy Audit

Typically the scope of an energy audit includes an examination of the following areas:

- Energy conversions in equipment such as boilers, furnaces, transformers, pumps, fans, compressors etc.
- Energy distribution (electricity, steam, condensate, compressed air, water etc.)
- Energy utilisation efficiency of equipment
- Production planning, operation, maintenance, and housekeeping
- Management aspects (information flow, data collection and analysis, feedback, achievements, training of employees, motivation, etc.)

- Other related areas such as water audit & conservation, waste minimization studies are sometimes included as part of an energy audit.

2.3 Types of Energy Audit

The type of energy audit depends on factors such as function, size, type of facility and depth of the study. Energy audit is classified broadly into two types: preliminary energy audit and detailed energy audit.

Preliminary energy audit	Detailed energy audit
• Short time frame, say few days to one week. • Uses readily available data for quick analysis and results are general • Focus on common opportunities for energy efficiency • Economic analysis is mostly limited to calculation of simple payback period • Broad recommendations	• Longer time frame, say 15–30 days • Uses operating data, detailed observations, measurements, energy and mass balance to assess energy performance • More specific recommendations for energy improvements covering all areas • Economic analysis may include internal rate of return, net present value, life cycle cost, as well as simple payback period • Detailed energy audit accounts for and evaluates all major energy using equipment and systems and provides specific recommendations with comprehensive implementation plan.

2.4 Detailed Energy Audit Methodology

The detailed audit is typically carried out in following stages:

- a) Initiating the audit
- b) Preparing the audit
- c) Executing the audit
- d) Reporting the audit
- e) Implementing the audit

A step-by-step guidance for conduct of energy audit at site is presented in the following Table. Energy auditors may follow these steps and amend them as per their needs and facility being audited.

Step-by-Step Guidance for Detailed Energy Audit

Step	Plan of Actions	Results
	a) INITIATING THE AUDIT	
Step 1	- Understand client needs and expectations. - Gather main data prior to site visit. - Define audit criteria and scope of audit.	- Overall operational strategy, major equipment/process and key technologies. - Historical and current data such as annual production, energy consumption, water consumption, performance indicators i.e. typical figures normally referred or quoted. - Decision on type of audit i.e. preliminary or detailed
	b) PREPARING THE AUDIT	
Step 2	- Plan resources for audit. - Prepare audit checklist.	- Resources (total time for the audit including timeline for each step). - Audit team and composition, responsibility of each team member. - Energy audit instruments needs.
Step 3	- Conduct opening meeting. - Establish common understanding of audit process (auditors and client).	- Safety briefing. - Company philosophy towards investment for energy savings. - Facility layout or plan.
	c) EXECUTING THE AUDIT	
Step 4	- Walk-through audit - Interview key facility personnel. - Gather on-site data.	- Plant/process activities, current operating practices, metering, monitoring and energy reporting system. - Broad process flow diagram. - Energy utility diagram.
Step 5	- Gather additional information through tailor-made questionnaire for each department. - Evaluate collected information and identify focus areas for detailed investigation.	- Energy tariffs and bills - Month wise current and historical energy and related production data (1-3 years). - Proportionate share of different energy sources when compared with total energy consumption for current year in a pie-chart. - Production performance and related energy consumption under varying conditions: days, months, seasons. - Design data, operating data, and schedule of operation of various equipment. - Breakdown of energy consumption by department/section as a pie-chart. - Baseline energy consumption.

Step 6	- Conduct onsite measurements and performance surveys using portable instruments, and panel mounted instruments (if available). - Conduct detailed performance trials for major energy equipment /systems.	- Comparison of operating / measurement data with design data (motor survey, lighting survey, fluid flow rates, temperatures). - Analysis of variation and trends (24 hours) of kVA, PF, kWh etc. - Efficiencies of major equipment such as boiler, furnace, chillers etc. - Load variations and trends in pumps, fan, chillers, refrigerators, cooling towers, compressors etc.
Step 7	Analyze use of energy, material and water use.	- Energy & material balance and assessment of energy losses/wastes. - Water conservation opportunities.
Step 8	Identify, develop and refine ENCON opportunities using brainstorming, vendor inputs etc.	- List of ENCON measures. - Technology options and budgetary offers from vendors.
Step 9	Evaluate ENCON opportunities (Cost-benefit analysis)	- Technical and financial feasibility of various ENCON measures. - Selected ENCON measures for implementation as short, medium, and long-term measures. <i>(Some short term measures may be implemented immediately at site and impact on energy savings can be demonstrated to the client.)</i>
d) REPORTING THE AUDIT		
Step 10	- Prepare a draft or working report for presentation to facility management. - Conduct closing meeting after submission of final report (soft copy).	- Highlights of the audit with key findings and ENCON measures. - Concurrence of draft report from all concerned or functional managers and modifications as required. - Submission of fine-tuned report (if required) as soft and hard copy. - Presentation to the facility management as the final appraisal.
e) IMPLEMENTING THE AUDIT		
	Implementing the audit findings is not normally the scope of an energy auditor. The client may seek implementation assistance particularly for technical inputs, evaluating the equipment supplier offers and for monitoring of the implementation of the projects. This may also be assigned as an extension of energy audit. The client can also seek the help of ESCOs in implementing ENCON options and monitoring the performance.	
Step 11	Prepare action plan for Implementation and follow-up.	- Action plan for implementation of ENCON options (DPR for major project) by facility management or through ESCO. - Monitoring and review by ESCO or facility management assisted by energy auditor.

		• Measurement and Verification.

Some of the salient points in the energy audit methodology are elaborated as follows:

Audit Criteria and Scope

These define purpose, depth, and methodology to be adopted by energy auditor for the given audit. In case of mandatory energy audit or compliance audit, the client defines the criteria and scope and provides basic energy data with raising of Expression of interest (EOI) or Request for proposal (RFP). Bureau of Energy Efficiency (BEE), GOI has outlined a detailed audit methodology to be followed, and it is available in the BEE website titled as 'Manner and Intervals of Time for Conduct of Energy Audit Regulations 2010'.

Sample Scope of Work (commercial buildings)

The energy audit consultancy organisation, based on site visits and diagnostic studies, shall cover all forms of energy i.e. both thermal and electrical for all systems and equipment.

A) Electrical Distribution System

- Review electrical distribution like single line diagram for transformer loading, cable loading, normal and emergency loading, and also electrical distribution in various areas.
- Study reactive power management and option for power factor improvement.
- Study power quality issues like harmonics, current imbalance, voltage imbalance, etc.
- Explore energy conservation options in electrical distribution system.

B) Motor Load Survey

- Conduct motor load survey of all drives to estimate % loading.
- Explore ENCON options in motor driven equipment and system.

C) Heating, Ventilation, & Air Conditioning System (HVAC System)

- Review present HVAC system like central AC, split AC, package AC, water coolers, and air heaters.
- Assess performance of split AC and package AC system.
- Assess performance of air handling units (AHUs) and central AC system.
- Compare HVAC performance such as KW/TR, specific energy consumption (SEC) of

chilled water pumps, condenser water pumps, AHUs with the design data.

- (v) Explore energy conservation options (ENCON) in HVAC system.

D) Water Pumping Systems

- (i) Review water pumping, storage, and distribution systems.
- (ii) Conduct water balance studies.
- (iii) Assess performance of all major water pumps i.e. power consumption vs. flow delivered, determination of pump efficiency etc.
- (iv) Explore Energy Conservation Options (ENCON) in water pumping system.

E) Lighting System

- (i) Examine present lighting system in all areas and assess lighting load (lighting inventory, lighting equipment, type, rating, nos and corresponding control gears)
- (ii) Measure lux levels at various locations and analyse lighting performance indices like lux/m², lux/watt, lux/watt/m² and compare with norms
- (iii) Evaluate possibilities to reduce energy use by incorporating energy efficient lighting system, equipment's including lay out changes
- (iv) Explore Energy Conservation Options (ENCON) in lighting system.

F) Others

- (i) Assess scope for integrating renewable energy into existing building.
- (ii) Cost benefit analysis indicating investment, energy saving, and payback period.

Initial Site Visit and Preparation

An initial site visit may be planned before the audit to give the energy auditor an opportunity to meet the top management and other department heads, to familiarize with the site, and to assess the procedures necessary to carry out energy audit. During the initial site visit, the energy auditor carries out the following actions:

- Discuss with the site's senior management the goals of the energy audit
- Obtain major energy consumption and production data
- Discuss the economic guidelines associated with the recommendations of the audit
- Tour the site accompanied by engineering/production staff
- Interview key personnel (energy manager/maintenance manager/finance manager/floor supervisors/operating staff)
- Identify major energy consuming areas/process to be audited

- Identify existing instruments and data available in the facility
- Identify list of parameters to be measured and the instruments needed during the energy audit
- Create awareness through a meeting/programme.

Selection of Energy Audit Team

The selection and composition of energy auditing team depends upon the type of industry to be audited. The audit team can be drawn from varied disciplines like mechanical, electrical, and chemical engineering. The areas having high potential for energy savings are identified and responsibilities and tasks of each audit member are defined.

Detailed Energy Audit Activities

Depending on the nature and complexity of the site, the detailed audit takes from several weeks to few months to complete. Energy and material balances for specific plant departments or items of process equipment are carried out. If required, checks of plant operations are carried out over extended periods of time, at nights, and at weekends to ensure that nothing is overlooked.

Information to be collected during detailed energy audit

- Plant layout
- Sources of energy supply (e.g. electricity from the grid or self-generation)
- Energy cost and tariff data (month wise energy consumption data for 1–3 years)
- Production data (1–3 years)
- Energy consumption by type of energy, by department, by major items of process equipment, by end-use
- Production process description with energy interaction
- Process flow diagram with energy and material flows
- Generation and distribution of site services diagram (e.g. compressed air, steam, chilled water, cooling water, etc.)
- Material balance data (raw materials, intermediate and final products, recycled materials, use of scrap or waste products, production of by-products for re-use in other industries, etc.)
- Energy management procedures and existing energy awareness training programmes.

The audit team should collect the following baseline data:

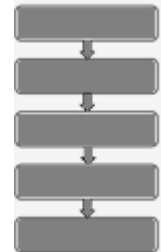
• Technology, processes used and equipment details • Capacity utilisation • Amount and type of input materials used • Water consumption	• Electrical energy consumption • Steam consumption • Type and quantity of wastes generated • Percentage rejection/reprocessing

- Fuel consumption

- Efficiencies/yield

Preparation of Process Flow Diagram and Listing Process Steps

An overview of unit operations, key process steps, areas of material and energy use, energy losses and waste generation are identified. Existing drawings, records and shop floor walk-through assist in preparing the flow chart. The inputs and outputs at each process step are identified and depicted in the flow chart.



Performance Evaluation and Trials for Major Equipment/Processes

Depending on the type of industry, data collection and trials cover areas such as air conditioning and refrigeration system, lighting, ventilation system, motors, pumps, fans, boilers, furnaces, compressors and other specialized equipment. The monitored parameters vary from one plant to another because of differences in designs and operations.

Energy Audit Instruments

Instruments for energy audit should be portable, durable, and easy to use. Energy audit instruments must be used only for measurements and not for calibrating panel instruments. Typical energy audit instruments include the following:

• Power analyser–3ϕ and 1ϕ (data logger optional) • Combustion analyser / Flue gas analyser • Power quality analyser / Harmonic analyser • Lux meter • Contact thermometers • Infrared non-contact temperature sensor • Manometers • Pitot tube with micro manometer or Digital manometer	• Vane anemometer • Tachometers - Stroboscopic tachometer • Ultrasonic Flow Meter • Anemometer • Psychrometer (Humidity measurements) • Temperature Probe • Ultrasonic stream trap tester • Thermal imaging devices • Miscellaneous instruments–leak detectors, pH meter, and TDS meter

Data Analysis

The field data collected during the audit has to be refined to enable analysis. Some of the steps involved in data analysis are listed as follows:

Computation of various parameters

The parameters not directly metered are computed using the measured data. Some examples include cooling load, which is computed using chilled water flow, chilled inlet and outlet temperatures. Similarly, chiller efficiency is computed using the actual cooling load and compressor motor power.

Tabulation and plotting of data

If the data is tabulated or plotted, operating trends and characteristics are easily interpreted. For example, variation of cooling load, voltage, kW, kVA, PF, % transformer loading with corresponding time (hourly reading over 24 hours) are plotted as a graph.



Comparing performance with design specifications

Performances of equipment or systems are compared with the design data so that gaps or possible improvements are identified. Following are some examples where actual performances are compared with design values:

• Chiller capacity and COP • Boiler capacity and efficiency • Chilled water flow • Chilled water supply and return temperatures • Condenser water flow • Condenser water supply and return temperatures	• Cooling tower capacity and performance • Pump flow, head, and motor power • Fan flow, static pressure, and motor power • Air handling unit (AHU) cooling capacity, supply, and fresh air flow • Motor power • Ventilation rates

Identification of Energy Conservation Opportunities

Fuel substitution

This involves identifying appropriate fuel for efficient energy conversion as well as lower cost, scope for introducing solar energy for hot water generation, drying, etc.

Energy generation

This involves identifying efficiency opportunities in energy conversion equipment/utility such as captive power generation, boilers, thermic fluid heaters, furnaces, cogeneration, energy-efficient DG sets, optimal loading of DG sets, and combustion with minimum excess air in boilers/thermic fluid heating, biomass gasifiers, etc.

Energy distribution

This involves identifying efficiency opportunities in electrical distribution system such as transformers, cables, switch gears, plant utility systems such as chilled water, cooling water, hot water, and compressed air.

Energy usage by processes

This consists of optimizing energy at end-use equipment such as steam using equipment, electrical end-use equipment such as fans, pumps, compressors, chillers. These are the areas where the opportunities for improvement are more.

Technical and Economic Feasibility

The technical feasibility addresses the following issues:

- The technology availability, space, skilled manpower, reliability, service.
- The impact of energy efficiency measures on safety, quality, production or process.
- The maintenance requirements and spares availability.

The financial viability often becomes the key for management acceptance of ENCON measures. Cost estimation is usually done by listing the scope of work necessary for each ENCON measures and using unit rates for the different tasks (if available), or by obtaining quotations from suitable contractors. Once the cost and saving for each measure is computed, the financial viability is considered based on agreed financial criteria. The various financial criteria for evaluating energy management projects are simple payback period, return on investment (ROI), net present value (NPV), and internal rate of return (IRR).

Classification of Energy Conservation Measures

Based on the energy audit and analyses, various energy saving projects are identified. These projects may be classified into three categories:

- a) Category I: measures involving housekeeping measures which are improvements with practically no cost investment and no disruption to the facility operation.
- b) Category II: measures involving changes in operation measures with relatively low cost investment.
- c) Category III: measures involving relatively higher capital cost investment to attain efficient use of energy.

Presenting Energy Audit Findings to Management

The limited time for onsite audit may not allow the auditor to carry out a detailed analysis of information collected during the audit. Before leaving the site, the key audit findings as a draft

or working report are presented to the senior management as an acknowledgment of energy saving measures identified at site.

Submission of Energy Audit Report

After leaving the site, the data collected during the field study are used to refine the ENCON measures and produce accurate estimates of savings from energy projects. Another presentation to the client as the final appraisal may be required. The fine-tuned energy audit report is presented as soft and hard copy. The report is authorized by the certified energy auditor or accredited energy auditor (for designated consumers).

Structure of Energy Audit Report

The table of contents of a typical energy audit report is as follows:

TABLE OF CONTENTS (Generic Energy Audit Report)

i. Acknowledgment

ii. Executive Summary

Summary of baseline energy and resource consumption

Energy saving options at a glance and recommendations

Types and priority of energy saving measures

1.0 Introduction about the Facility/Plant/Building

1.1 General plant details and descriptions

1.2 Energy audit team

1.3 Scope, Methodology and Instruments used

1.4 Component of production cost (raw materials, energy, chemicals, manpower, overhead, others)

1.5 Major energy use and areas

1.6 Baseline scenario

2.0 Production Process Description

2.1 Brief description of manufacturing process

2.2 Process flow diagram and major unit operations

2.3 Major raw material Inputs, quantity, and costs

3.0 Energy and Utility System Description

3.1 List of utilities

3.2 Brief description of each utility

3.2.1 Electricity

3.2.2 Steam

3.2.3 Water

3.2.4 Compressed air

3.2.5 Chilled water

3.2.6 Cooling water

4.0 Detailed Process Flow Diagram and Energy & Material Balance

4.1 Flow chart showing flow rate, temperature, pressures of all Input /output streams

4.2 Water balance for entire industry

5.0 Energy Efficiency in Utility and Process Systems

5.1 Specific energy consumption

5.2 Boiler efficiency assessment

5.3 Thermic fluid heater performance assessment

5.4 Furnace efficiency analysis

5.5 Cooling water system performance assessment

5.6 DG set performance assessment

5.7 Refrigeration system performance

5.8 Compressed air system performance

5.9 Electric motor load analysis

5.10 Lighting system

6.0 Energy Conservation Measures & Recommendations

6.1 List of options in terms of no cost/low cost, medium cost and high investment cost, annual energy and cost savings, and payback

6.2 Implementation plan for energy saving measures/projects

ANNEXURES

A1. List of energy audit worksheets

A2. List of instruments

A3. List of vendors and other technical details

The common energy audit reporting formats with the useful tables are presented as follows:

Table 2.1 shows summary of baseline energy and resource consumption and Table 2.2 shows energy saving options at a glance and recommendations as part of executive summary.

Table 2.1: Summary of Baseline Energy and Resource Consumption

Baseline Energy Data	Electricity	Natural Gas	Diesel, HFO, etc.	Water	GHG
Consumption / Year					
Cost / Year					

Table 2.2: Energy Saving Options at a Glance and Recommendations

S. No.	Description of energy saving measure	Annual Energy (Fuel & Electricity) Savings (kWh/MT or KL/MT)	Annual Savings Rs. Million	Capital Investment (Rs. Million)	Simple Payback period
1.					
2.					
3.					
Total					

The table 2.3 shows prioritizing energy saving measures as no investment (quick returns), low investment (short to medium term return) and high investment (long term return) types.

Table 2.3: Types and Priority of Energy Saving Measures

Category	Type of Energy Saving Options	Annual Electricity / Fuel Savings kWh/MT or KL/MT	Annual Savings (Rs. Million)	Priority
A	No Investment (Immediate) - Operational Improvement - Housekeeping			
B	Low Investment (short to medium term) - Controls - Equipment modification - Process change			
C	High Investment (long term) - Energy efficient devices - Product modification - Technology change			

2.5 Implementing Energy Efficiency Measures

On completion of energy audit, the management team reviews the report and decides on the course of action. At this point, the facility is ready to prioritise and implement various ENCON measures and tool such as ISO 50001 is highly useful.

Role of ESCO

ESCO is an organisation engaged in a performance based contract with a client firm to implement measures which reduce energy consumption and costs in a technically and financially viable manner. ESCO can be engaged to conduct detailed energy audit from the beginning or can be involved later in implementation of detailed energy audit measures. The ESCO evaluates the detailed energy audit in order to offer a comprehensive efficiency solution that captures all energy efficiency opportunities and not just the obvious ones. This is carried out by preparing a detailed project report (DPR).

2.6 Detailed Project Report (DPR)

Detailed project report (DPR) is prepared for investment decision-making approval and execution of project. The project can be any of the following: setting up new equipment, new process, facility upgrades and even maintenance-driven issues promoting energy conservation and efficiency.

A typical DPR includes the following:

- Examination of technological parameters
- Description of the technology to be used
- Broad technical specification
- Evaluation of existing resources
- Project schedule/execution plan
- General layout
- Volume of work

2.7 Understanding Energy Costs

Energy cost is needed for saving calculations and awareness creation. In many industries sufficient meters may not be available to measure all the energy used. In such cases, invoices for fuels and electricity are used. The annual company balance sheet is another source to get fuel and power cost along with production related information.

Energy invoices can be used for the following purposes:

- They give details of energy used and costs.
- Energy purchased in a given year can be used as a baseline for setting targets.
- Energy data can be related to production or any other variable affecting energy consumption to establish performance indicators
- Invoices over the years can point out energy and cost savings made through energy conservation measures
- They can suggest where energy savings are most likely to be made.

Fuel costs

A wide variety of fuels are available for thermal energy supply namely,

- Fuel oil
- Low Sulphur Heavy Stock(LSHS)
- Light Diesel Oil(LDO)
- Natural gas
- Liquefied Petroleum Gas(LPG)
- Coal
- Lignite
- Wood etc.

Fuel is normally purchased in Tons or Kilolitres. The following factors should be considered during procurement of fuel:

- Price at source, transport charge, type of transport
- Quality of fuel (contaminations, moisture etc.)
- Energy content (calorific value)
- Power costs

The final cost of electricity (power) involves the following factors:

- Maximum demand charges, KVA/kW (i.e. rate at which electricity is used?)
- Energy Charges, kWh (i.e., How much electricity is consumed?)
- Time of Day (TOD) Charges, Peak/Non-peak period (i.e. When electricity is utilized?)
- Power factor Charge, P.F. (i.e., Real power use/Apparent power use)
- High tension (HT) tariff and low tension (LT) tariff rates
- Slab rate cost and its variation
- Applicable incentives and penalties
- Consumer categories such as commercial, residential, industrial, Government, agricultural, etc.
- Tariff rate for developed and under developed area/States

2.8 Benchmarking and Energy Performance

Benchmarking of energy consumption is a powerful tool for performance assessment and improvement. Historical data shows energy consumption and cost year-wise, month-wise and day-wise. Analyzing trends of energy consumption, energy cost and relevant production, specific energy consumption helps to

understand the effects of capacity utilizations on energy use efficiency and costs.

External benchmarking relates to inter-unit comparison across similar units. Similarities should be confirmed as otherwise findings can be grossly misleading. Few comparative factors to be considered for external benchmarking are:

- Scale of operation
- Vintage of technology (new or old technology)
- Raw material specifications and quality
- Product specifications and quality

Benchmarking energy performance allows:

- Quantification of fixed and variable energy consumption trends against production levels
- Comparison of the industry energy performance with respect to various production levels (capacity utilization)
- Identification of best practices (based on the external benchmarking data)
- Scope and margin available for energy consumption and cost reduction
- Basis for monitoring and target setting exercises.

Examples of benchmarking parameters for various sectors, industries and equipment are listed as follows:

Gross production related:

Cement plant	kWh/MT clinker or cement produced
Textile unit	kWh/kg yarn produced
Paper plant	kWh/MT, kCal/kg, paper produced
Power plant	Heat rate, kCal/kWh Power produced
Ammonia (Fertilizer plant)	Million kilocal/MT Urea
Foundry	kWh/MT of liquid metal output

Equipment / utility related:

Air conditioning plant	kW/TR (tons of refrigeration)
Boiler plant	% thermal efficiency
Cooling tower	% cooling tower effectiveness
Compressor	kWh/NM ³ of compressed air generated
diesel power generation plant	kWh/litre

While assessing benchmarks, related process parameters should also be collected for comparison between industries of the same sector namely,

Cement plant	Type of cement, blaine number (fineness) i.e. Portland and process used (wet/dry) are to be reported along with kWh/MT.
Textile unit	Average count, type of yarn i.e. polyester/cotton, are to be reported along with kWh/square meter.
Paper plant	Paper type, raw material (recycling extent), GSM quality are reported along with kWh/MT, kCal/Kg
Power plant / cogeneration plant	Plant % loading, condenser vacuum, inlet cooling water temperature is mentioned along with heat rate (kCal/kWh).
Fertilizer plant	Capacity utilization (%) and on-stream factor are compared along with specific energy consumption.
Foundry unit	Melt output, furnace type, composition (mild steel, high carbon steel/cast iron etc.), raw material mix, number or power trips are operating parameters reported along with specific energy consumption data.
Air conditioning (A/c) plant	Chilled water temperature level and refrigeration load (TR) are crucial for comparing kW/TR.
Boiler plant	Fuel quality, type, steam pressure, temperature and flow are reported along with thermal efficiency. Also, whether thermal efficiency is on gross calorific value basis or net calorific value basis or whether the computation is by direct method or indirect heat loss method is significant in benchmarking exercise.
Cooling tower effectiveness	Ambient air wet/dry bulb temperature, relative humidity, air and circulating water flows are reported to make meaningful comparison.
Compressed air specific power consumption	Inlet air temperature and pressure of generation
Diesel power plant performance	Similar loading %, steady run condition

2.9 Plant Energy Performance

Plant energy performance is the measure of whether a plant is now using more or less energy to manufacture its products than it did in the past. In short, it tells us how well energy management programme is doing.

It compares the change in energy consumption from one year to another year considering production output. Plant energy performance monitoring compares plant energy use at a reference year with the subsequent years to determine the improvement that has been made. However, plant production is likely to vary from year to year and has effect on energy consumption.

For a meaningful comparison, the energy that would have been required to produce this year production output, if the plant had operated in the same way as it did during the reference year is calculated. This calculated value can then be compared with the actual value to determine the improvement or deterioration that has taken place since the reference year.

Production Factor

Production factor is used to determine the energy that would have been required to produce this year's production output if the plant had operated in the same way as it did in the reference year. It is the ratio of production in the current year to that in the reference year.

$$\text{Production Factor} = \frac{\text{Current year production}}{\text{Reference year production}}$$

Reference Year Equivalent Energy Use

Reference Year Equivalent Energy Use or reference year equivalent in short is the reference year's energy use that would have been used to produce current year production output.

The reference year equivalent is obtained by multiplying the reference year energy use by the production factor (obtained above).

Reference year equivalent = Reference year energy use * Production factor

The plant energy performance is calculated using the following relation:

$$\text{Plant energy performance} = \frac{\text{Reference year equivalent} - \text{Current year energy}}{\text{Reference year equivalent}} \times 100$$

The energy performance is the percentage of energy saved or lost at the current rate of use compared to the reference year rate of use.

The integrated paper plant has produced 119366 MT of paper during the year 2015-16. The management has implemented various energy conservation measures and had reduced the specific energy consumption from 53 GJ/ tonne of product to 50 GJ/tonne of product in the assessment year (2017-18). The corresponding production in assessment year was 124141 MT. Calculate the plant energy performance and states your inference.

Reference year production = 119366 MT

Reference year specific energy consumption = 53 GJ/tonne of product

Assessment year production = 124141 MT

Assessment year specific energy consumption = 50 GJ/tonne of product

$$\text{Production Factor} = \frac{\text{Assessment year production}}{\text{Reference year production}}$$

$$\text{Production factor} = (124141 / 119366) = 1.04$$

$$\begin{aligned} &\text{Reference year energy consumption, GJ} \\ &= \text{Reference year specific energy consumption, } \frac{\text{GJ}}{\text{MT}} \times \text{Reference year production, MT} \end{aligned}$$

$$= 53 \times 119366 = 6326398 \text{ GJ}$$

$$\begin{aligned} &\text{Assessment year energy consumption, GJ} \\ &= \text{Reference year specific energy consumption, } \frac{\text{GJ}}{\text{MT}} \times \text{Assessment year production, MT} \end{aligned}$$

$$= 50 \times 124141 = 6207050 \text{ GJ}$$

$$\begin{aligned} &\text{Reference year equivalent energy use, GT} \\ &= \text{Reference year energy consumption, GJ} \times \text{Production Factor} \end{aligned}$$

$$= 6326398 \text{ GJ} \times 1.04 = 6579454 \text{ GJ}$$

$$\begin{aligned} &\text{Plant energy performance, \%} \\ &= \frac{\text{Reference year equivalent energy} - \text{Assessment year energy}}{\text{Reference year equivalent energy}} \times 100 \end{aligned}$$

$$= ((6579454 - 6207050) / 6579454) \times 100$$

$$= 5.66\%$$

$$\text{Plant energy performance, \%} = 5.66$$

Inference: plant energy performance is positive and hence the plant is achieving energy savings.

Monthly Energy Performance

Plant energy performance is based on yearly energy information, progressive management asks for monthly information

Once the plant has started measuring yearly energy information, management may ask for monthly information and use it as a tool to control energy use on an on-going basis.

2.10 Matching Energy Usage to Requirement

If the capacity of the equipment is much larger than use requirements, the equipment operates at part-load leading to inefficiency and wastage. This type of situations normally

happens at design stage. Energy manager has to look for ways to match energy equipment capacity to end-use needs. Some examples are:

Pump capacity (flow) more than required and throttled: Energy manager can eliminate throttling of a pump by impeller trimming, installing variable frequency drive, replacing existing pump with a smaller pump.

Similarly for a centrifugal fan operated with a damper for flow control can be operated with impeller trimming, installing variable frequency drive, pulley modification (Fan-motor pulley driven system), replacing existing fan with a smaller fan.

For a chiller with excess capacity, chilled water temperature can be controlled to meet process chilling need.

Energy (steam) loss in a pressure control valve (PRV) can be recovered with a back pressure turbine (micro turbine) adoption.

Task lighting can be adopted in place of area lighting to avoid lighting over an entire area.

2.11 Maximising System Efficiency

Once the energy source and usage is matched, next step is to operate the equipment efficiently using best operation and maintenance practices. Some examples are:

- Eliminate steam leakages by steam trap maintenance
- Maximise condensate recovery
- Adopt combustion controls for maximizing combustion efficiency in boilers/furnaces
- Reduce air leaks in compressed air system
- Periodically clean and maintain air filters in air cooling system

2.12 Instruments and Metering for Energy Audit

The quantification of energy use in an energy audit requires the use of various instruments for monitoring and measurements. These instruments must be portable, durable, easy to operate and relatively inexpensive. The operating instructions for all instruments must be understood and staff should familiarize themselves with the instruments and their operation prior to actual audit use. The key instruments for energy audit are listed in the following Table:

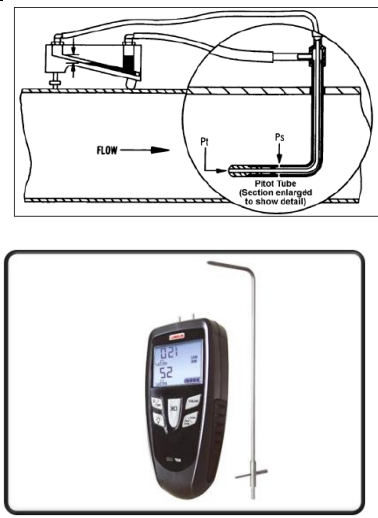
Table 2.4: Key Instruments for Energy Audit

No.	Name of the Instrument	Features and Typical Applications
1.	Power & Harmonic Analyser 	Measures all Electrical and Harmonic Parameters namely, V, A, PF, KW, kVA, kVAR, Hz, and first 50 Harmonics. These instruments can be applied on-line i.e. on running motors without any need to stop the motor. Instant measurements can be taken with hand-held meters, while more advanced ones facilitates cumulative readings with printouts at specified intervals say every 1/2 hr over a shift or a day.
2.	Tachometer (Contact-type) 	A tachometer is an instrument used to measure the rotational speed of a shaft or wheel in revolutions per minute (rpm). By measuring speed, energy auditor is able to find out belt slip if any and loading. A contact type tachometer can be used where direct access is possible.
3.	Non-Contact Tachometer / Stroboscope 	Non-contact tachometer allows the users to measure the rotational speed without contacting the object. Non-contact instruments are sophisticated and safer. These instruments can measure speed for objects that are visible but not accessible. A stroboscopic tachometer employs a variable-frequency, flashing light which makes the rotating component appear to stand still when the frequencies match.
4.	Lux meter 	A lux meter is a device for measuring illumination or lighting levels. The lux is a unit of measurement of illuminance (brightness). A lux meter works by using a photo cell to capture light. The light is then converted to an electric current and corresponding lux value.

5.	Combustion / Flue Gas Analysers 	Combustion analyser measures the composition of flue gases in percentage (% O₂ (or) % CO₂), and flue gas temperature. The instrument estimates the combustion efficiency of furnaces, boilers and other fossil fuel-fired devices with an inbuilt programme. Two types are available: digital analyzers and manual combustion analysis kits. Digital combustion analysis equipment performs the measurements and reads out combustion efficiency in percentage. The manual combustion analysis kits typically require multiple measurements including exhaust stack: temperature, oxygen content, and carbon dioxide content. The efficiency of the combustion process can be calculated after determining these parameters. The manual process is tedious and is frequently subject to human error.
6.	Thermometer  	These thermocouples measures temperatures of flue gas, hot air, hot water by insertion of appropriate probe into the stream. Different types include Fluid Filled, Resistance, Thermocouple and Thermistor. Most HVAC applications require a thermometer with temperature of -50°C to 175°C. Boiler and oven stacks require thermometers able to measure up to about 500°C. By knowing the process temperature, the auditor can determine process equipment efficiency. It also helps us to waste heat recovery potential. For surface temperature, a leaf type probe is used with the same instrument.
7.	Fyrite Gas Analyzer	This instrument is used for measuring and analyzing carbon dioxide or oxygen. The instrument contains absorbing fluid which is selective in the chemical absorption of carbon dioxide or oxygen, respectively. Fyrite readings are unaffected by the presence of most background gases in the sample. Fyrite accuracy is sufficient for most industrial applications and test procedure is simple.

		
8.	Infrared Thermometer (Non-contact type) 	The instrument is basically non-contact type which is able to measure temperature from a distance. Non-contact infrared thermometers, also known as heat guns, are very useful for measuring surface temperatures of steam lines, boiler surfaces, processes temperatures, etc. An infrared thermometer infers temperature from a portion of the thermal radiation sometimes called blackbody radiation emitted by the object being measured (as radiation is characteristic of their temperature). By knowing the amount of infrared energy emitted by the object and its emissivity, the object's temperature can be determined. The heart of the infrared thermometer is the detecting surface, which absorbs infrared energy and converts it to an electrical voltage or current. These instruments typically cover a range from 30°C to 2000°C.
9.	Thermal Imaging Devices 	Thermal cameras are instruments that create pictures of heat rather than light. They measure infrared (IR) energy and convert the data to corresponding images of temperatures. Non-contact infrared imagers provide fast, safe, accurate measurements for objects that are: ▪ Moving or very hot ▪ Difficult to reach ▪ Impossible to shut-off ▪ Dangerous to contact ▪ Where contact would damage, contaminate or change temperature.

10.	Ultrasonic Flow Meter 	Water and other fluid flows in pipelines can be easily measured using ultrasonic sensors mounted on the pipelines. This instrument is used to estimate the flow rates entering or leaving a pump. The meters are used to determine the fluid flow in terms of velocity and flow rate (given the diameter of pipe). This non-contact flow measuring device uses Doppler effect / Ultra sonic principle. A transmitter and a receiver are positioned on opposite sides of the pipe. Modes of operation and measurement are either by Doppler effect (or) Transit Time.
11.	Thermo-anemometer 	This instrument is used for measuring air velocity in ventilation, air-conditioning and refrigeration systems etc.
12.	Thermo-hygrometer 	This instrument measures humidity and temperature for determination of dew point and calculation of heat being carried away by out-going gases where product drying requires hot air.
13.	Ultrasonic Steam Trap Tester 	These instruments operate as electronic stethoscopes. They are able to pick up the very high-pitched sound indicative of freely blowing steam (condensate draining makes a lower-pitched sound). The advantage of ultrasonic testers is that they can listen to one pipe and detect if any of the nearby steam traps have failed. Ultrasonic detecting devices can also be used to identify any type of gas or fluid leaks e.g. compressed air leaks.
14.	Pitot Tube and manometer (Inclined /Digital manometer)	Air velocity in ducts can be measured using a pitot tube and an inclined manometer for further calculation of flows. The principle is based on measuring the differential

		(velocity) pressure at various points (traverse points) across the cross-section of the duct. In addition to velocity pressure, this instrument can also determine Static and Total pressures.
15.	Leak Detectors 	Compressed air is one of the most costly utilities in a facility today. A simple program of leak inspection and repair helps greatly to reduce energy costs. Ultrasonic Leak Detector has an high quality flexible sensor is mounted on the end of a flexible steel pipe so the ultrasonic sound sensor can access hard to reach areas. The unit converts the ultrasonic noise of a leak into a sound a human can hear such as some beeping sound or LED display. Features of this instrument are • Detects the location of leaks • Detects almost any leak because – Short distance/access not needed – High pressure not needed – Sensitive to sound – Filters background noises This instrument does <u>not</u> measure the size of the leak.
16.	Conductivity Meter 	This instrument is used for spot analysis of the amount of total dissolved solids (TDS) in water especially in case of boiler blow down. An accurate measurement of TDS is required to maintain blow down rate in boilers and optimize energy consumption. TDS meter measures the conductivity of the solution then converts that value to an equivalent TDS reading.

17.	pH meter 	pH meter is used for spot analysis of acidity or alkalinity of a solution/water.. The meter uses the property of certain types of electrodes to exhibit electrical potential when immersed in a solution.
18.	Thermal Insulation scanner	This instrument measures loss of energy in kCal per unit area from hot/cold insulated surfaces. The total heat loss can be obtained by multiplying the value with total surface area.

Chapter 3

Energy Management System (EnMS): ISO 50001: 2018

3.1 Introduction

Energy management makes good business sense as energy costs is a significant portion in an organisation's budget. Individual organization cannot control energy prices, government policies or the global economy, but they can very well improve the way they manage energy in their organizations.

A systematic focus on energy management, through optimum use of resources and reduction in wastes, is expected to reduce cost. It can also lead to increased production, improved energy performance, higher profits, and reduced impacts due to rising energy prices. A reduction in energy consumption will also lower CO₂ emissions to the environment, and the organisation thereby contributes its part to addressing the climatic change objectives of the country.

Despite these opportunities for energy savings and efficiency improvements, organisations hesitate implementing measures and reaping the benefits of potential reduction in operation costs. Most companies do not understand how much energy they currently use and how much they potentially save by implementing an EnMS. Another barrier in achieving energy savings is the lack of commitment at all levels, especially top management in the organization, to make changes necessary to achieve these improvements.

In order to manage energy well, an organization requires an effective Energy Management System (EnMS) to be established, implemented, maintained and continually improved. There are two ways to doing it; they can develop and implement their own Energy Management System or they can implement Energy Management System conforming to ISO 50001.

3.2 Why ISO 50001 to Manage Energy Effectively?

It is in the interest of the organizations to go for ISO 50001 since it is based on the management system model that is already understood and implemented by organizations worldwide. It can make a positive difference for organizations of all types immediately even without any investment, while supporting longer term efforts for capital intensive energy-efficient technologies.

In order to spur interest in energy efficiency and help organisation take appropriate actions to overcome barriers in implementing practical energy saving measures, International Organisation for Standardisation (ISO) had released the first version of '**ISO 50001 Energy Management Systems (EnMS)–Requirements with guidance for use**' in June 2011 and revised version of **ISO 50001:2018** in **August, 2018**.

3.2.1 Energy Performance Approach

The standard provides requirements for a systematic, data-driven and facts-based process, focused on continually improving energy performance. Energy performance is a key element integrated within the concepts introduced in the standard in order to ensure effective and measurable results over time. Energy performance is a concept which is related to energy efficiency, energy use and energy consumption.

ISO 50001 has made a major leap in 'raising the bar' by requiring an organization to demonstrate improved energy performance. There are no quantitative targets specified; an organization can choose its own targets and create an action plan to meet the targets. With this structured approach, an organization is more likely to see tangible financial benefits. Energy Performance Indicators (EnPIs) and energy baselines (EnBs) are two interrelated elements addressed in this document to enable organizations to demonstrate energy performance improvement.

3.2.2 Relationship between Energy Performance and the EnMS

The ISO 50001 standard addresses both energy performance improvement and a management system approach to manage energy. The clause no. 4 of the standard on the context of organization, requires continual improvement of EnMS as well as energy performance to achieve intended outcomes. Accordingly, the EnMS promotes, supports and sustains the Energy Performance Improvement; achievement of other intended outcomes; and its continual improvement as illustrated in Figure 3.1.

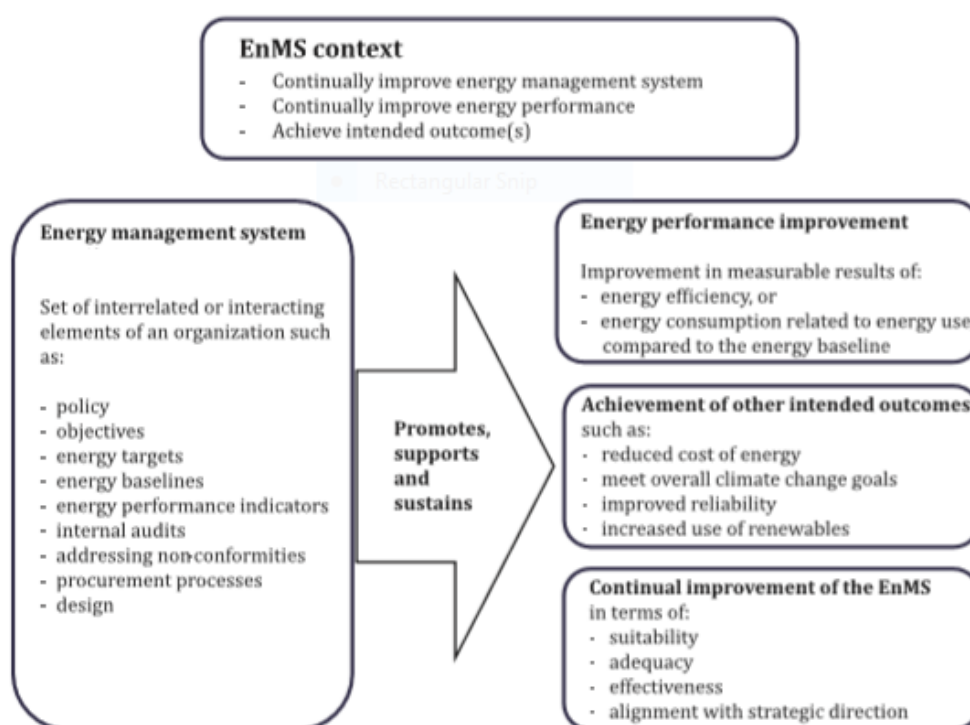


Figure 3.1 – Relationship between EnMS and Energy Performance

3.2.3 Plan-Do-Check-Act (PDCA) cycle

The EnMS described in the standard is based on the Plan-Do-Check-Act (PDCA) continual improvement framework and incorporates energy management into existing organizational practices, as illustrated in Figure 3.2.

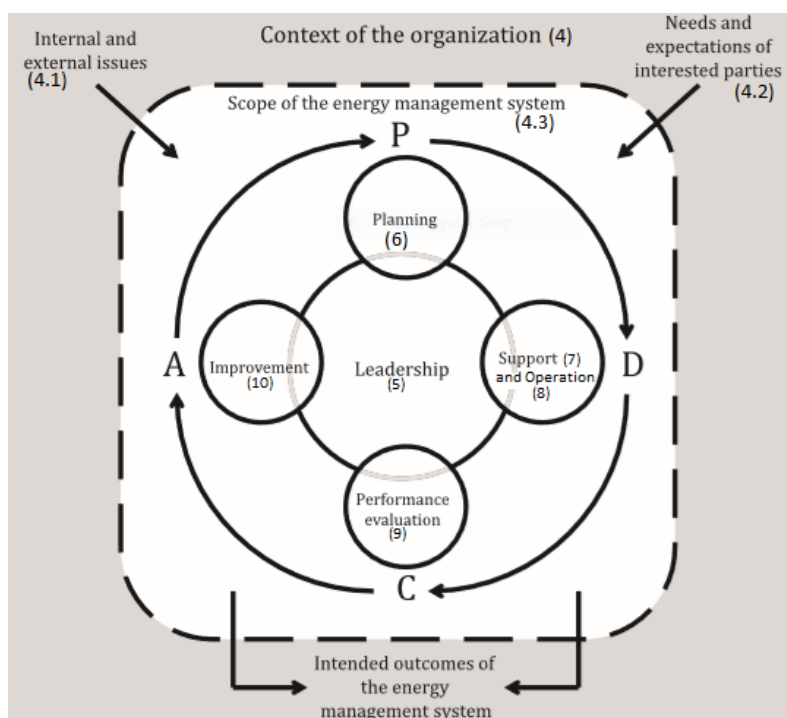


Figure 3.2 – PDCA cycle

The PDCA Approach to EnMS

Plan: understand the context of the organization, establish an energy policy and an energy management team, consider actions to address risks and opportunities, conduct an energy review, identify significant energy uses (SEUs) and establish energy performance indicators (EnPIs), energy baseline(s) (EnBs), objectives and energy targets, and action plans necessary to deliver results that will improve energy performance in accordance with the organization's energy policy.

Do: implement the action plans, operational and maintenance controls, and communication, ensure competence and consider energy performance in design and procurement.

Check: monitor, measure, analyse, evaluate, audit and conduct management review(s) of energy performance and the EnMS.

Act: take actions to address nonconformities and continually improve energy performance and the EnMS.

3.3. Benefits of Implementing ISO 50001

The implementation of ISO 50001 will provide following benefits:

- a) provide organizations with a well-recognized framework for integrating energy efficiency into their management/business practices,
- b) provide a logical and consistent methodology for identifying and implementing improvements that can contribute to a continual increase in energy efficiency across the facilities,
- c) assist organizations to better utilize existing energy consuming assets, thus reducing costs and/or expanding capacity,
- d) offer guidance on benchmarking, measuring, documenting, and reporting energy efficiency improvements
- e) lead organizations to meet overall climate change mitigations goals by reducing their energy related greenhouse gas emissions,
- f) assist facilities in evaluating and prioritizing implementation of state-of-the-art energy-efficient technologies,
- g) provide an approach for organizations to encourage suppliers to better manage their energy, thus promoting energy efficiency throughout the supply chain.

3.4 Why a New ISO 50001 Version?

It is a part of continual improvement that every management standard is periodically reviewed. This version change is driven by high-level structure (HLS) implementation. The purpose of HLS is to make ISO 50001 comparable and compatible to other standards such as ISO 9001:2015 and ISO 14001:2015. This will help organization implementing or maintaining Integrated Management System (IMS).

The new version is targeted to build energy culture in an organization. Adoption of HLS is expected to make process owner more responsible for all systems rather than a single management system.

The new version also brings risk management approach—risk management, risk analysis—in energy management system.

Salient feature of HLS:

- A common structure for all Standards (ISO 9001, ISO 14001) etc.
- 10 clauses in all
- HLS structure + energy management specific clauses

All ISO Standards will now follow ten clauses recommended by HLS and few additional clauses which are specific to that particular standard.

The main changes compared to the previous version of ISO 50001:2011 are as follows:

- (i) adoption of ISO's requirements for management system standards, including a high-level structure, identical core text, and common terms and definitions, to ensure a high level of compatibility with other management system standards;
- (ii) better integration with strategic management processes;
- (iii) clarification of language and document structure;
- (iv) stronger emphasis on the role of top management;
- (v) adoption of context order for the terms and their definitions in Clause 3 and update of some definitions;
- (vi) inclusion of new definitions, including energy performance improvement;
- (vii) clarification on exclusions of energy types;
- (viii) clarification of "energy review";
- (ix) introduction of the concept of normalization of energy performance indicators [EnPI(s)] and associated energy baselines [(EnB(s))];
- (x) addition of details on the energy data collection plan and related requirements (previously energy management plan): and
- (xi) clarification of text related to energy performance indicators [EnPI(s)] and energy baselines [EnB(s)].
- (xii) addition of details on the energy data collection plan and related requirements (previously energy measurement plan);
- (xiii) clarification of text related to energy performance indicators [EnPI(s)] and energy baselines [EnB(s)] in order to provide a better understanding of these concepts.

The chapter numbers from here onwards are revised to match with Clause Numbers of ISO 50001:2018 standard to avoid any confusion. This chapter clarifies the requirements of the standard and how to meet those. To know the exact requirements under each clause, ISO 50001:2018 standard should be referred.

Interpretation of key words used in the standard

It may be noted that in the new standard, "shall" indicates a requirement; "should" indicates a recommendation; "can" indicates a possibility or a capability; and "may" indicates permission.

Besides, it should be remembered that

- (i) the use of the word "any" implies selection or choice,
- (ii) the words "appropriate" and "applicable" are not interchangeable. "Appropriate" means suitable (for, to) and implies some degree of freedom, while "applicable" means relevant or possible to apply and implies that if it can be done, it needs to be done,
- (iii) the word "consider" means it is necessary to think about the topic but it can be excluded, whereas "take into account" means it is necessary to think about the topic but it cannot be excluded, and
- (iv) the word "ensure" means the responsibility can be delegated, but not the accountability.

Requirements of ISO 50001:2018

- 1 Scope** – Gives scope of the standard.
- 2 Normative references** – There are no normative references in this document.
- 3 Terms and definitions** – Gives definitions of various terms used. In new version, definitions have been divided into five categories and in place of 28 definitions in old version, there are 41 definitions in new version.
- 4 Context of organization**

4.1 Understanding the organization and its context

The organization is required to determine external and internal issues that are relevant to its purpose and that affect its ability to achieve the intended outcome(s) of its EnMS and improve its energy performance. The analysis of organizational context will provide a high-level conceptual understanding of the external and internal issues that can affect, either positively or negatively, energy performance and the EnMS of the organization.

External issues could be related to interested parties such as existing national or sector objectives, requirements or standards; restrictions or limitations on energy supply, security and reliability; energy costs or the availability of types of energy; effects of weather; effects of climate change; effect on greenhouse gas (GHG) emissions etc.

Internal issues could include core business objectives and strategy; asset management plans; financial resource (labour, financial, etc.) affecting the organization; energy management maturity and culture; sustainability considerations; contingency plans for interruptions in energy supply; maturity of existing technology etc.

4.2 Understanding the needs and expectations of interested parties

Under this clause, the organization is supposed to identify the interested parties that are relevant to energy performance and the EnMS; the relevant requirements of these interested parties; and which of the identified needs and expectations need to be addressed by the organization through its EnMS.

Interested parties (stakeholders) can include Suppliers, Customers, Partners, Employees, Investors, Owners, Bankers/financial bodies, Regulatory bodies, Unions, Competitors, Society, Opposing pressure groups, government, shareholders etc.

Organization is also required to ensure that it has access to the applicable legal requirements and other requirements related to its energy efficiency, energy use and energy consumption; determine how these requirements apply to its energy efficiency, energy use and energy consumption; ensure that these requirements are taken into account and reviewed at defined intervals.

Legal requirements are laws and acts that apply to an organisation's energy use, consumption, and efficiency. These may include Energy Conservation Act, Boiler Act, Water Pollution Act, Air Pollution Act, Electricity Act, Factory Act etc. as applicable to the organization. Besides these, there may be some regional, national, or international laws that may apply to an organisation.

Other requirements that may apply to the organization include voluntary agreements, corporate agreements/targets, agreements with customers and suppliers, requirements of trade associations, agreements with community groups or NGOs etc.

A list of all applicable legal and other requirements relevant to energy should be developed, and the organisation needs to decide how these requirements apply to its activities and how compliance can be effectively ensured as shown in Figure 3.3. The entire process of identification and evaluation should be clear and include a description of how compliance is assessed. Best method would be to establish the responsibility for identification, compliance and monitoring and reviewing compliance.

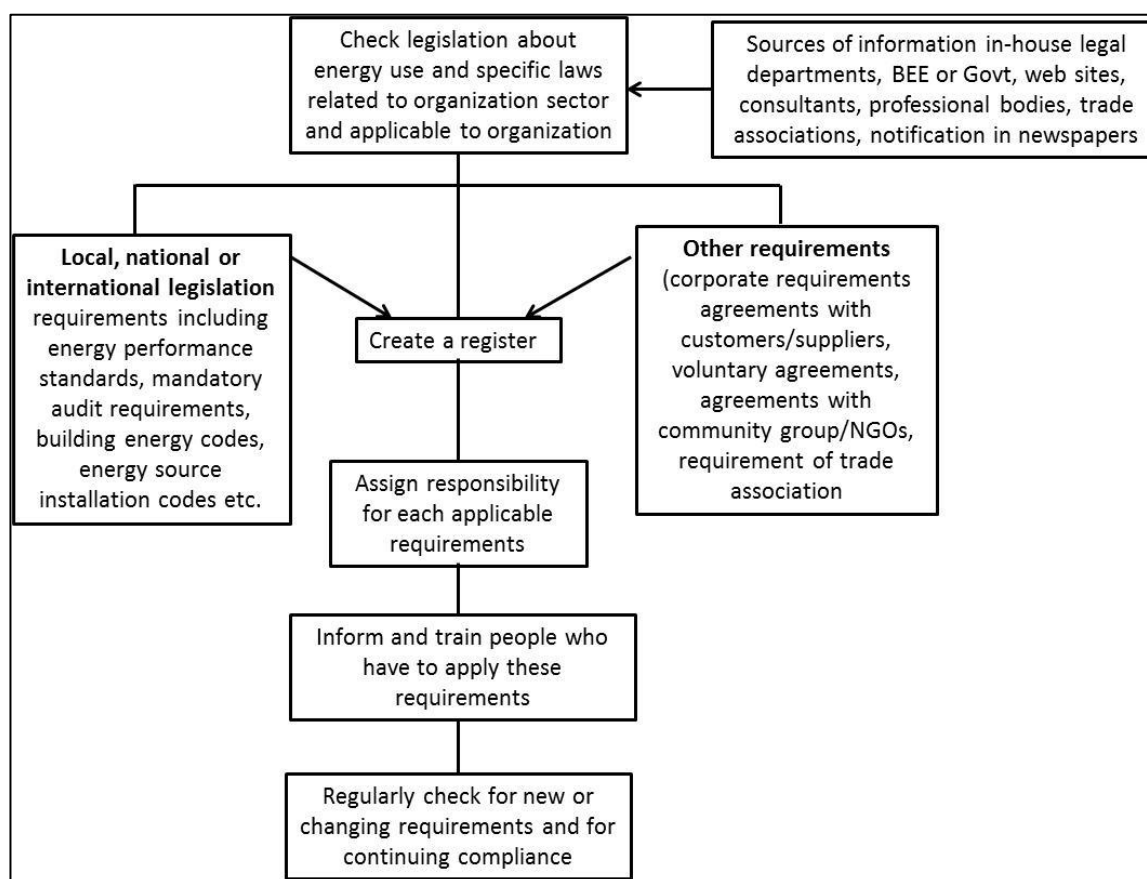


Figure 3.3: Addressing Legal and Other Requirements

The ISO 50001 standard requires organization to review legal requirements and other requirements at defined intervals. However, in addition to this interval, there might be some occasions when organization needs to review these requirements and such occasions could be changes to applicable legal and other requirements as well as changes in organization's operations that might affect applicability of these requirements.

4.3 Determining the scope of energy management system

The organization is required to determine and document the scope and boundaries to be covered in its EnMS to establish its scope. While determining the EnMS scope, the organization is required to consider the external and internal issues referred to in 4.1 as well as the requirements referred to in 4.2.

Scope covers facilities, operations, products and activities whereas boundaries cover parts of the site on which it has the authority to control its energy efficiency, energy use and energy consumption. In the new version, the organization cannot exclude an energy type within the scope and boundaries of EnMS.

4.4 Energy management system

The organization is required to establish, implement, maintain and continually improve an EnMS, including the processes needed and their interactions, and continually improve energy performance in accordance with the requirements of this document. The processes needed will depend on the size of organization and its type of activities, processes, products and services; the complexity of processes and their interactions; and competence of personnel.

5 Leadership

5.1 Leadership and commitment

New version of the standard has put stronger emphasis on the role of top management wherein it is required to demonstrate its leadership and commitment with respect to continual improvement of its energy performance and effectiveness of the EnMS by way of fulfilling a number of responsibilities mentioned therein. Top management can delegate some of those responsibilities but the overall accountability will still lie with top management.

Top management support is a prerequisite to the successful implementation of an energy management system. Top management should provide the necessary resources such as time, manpower, money, materials for effective implementation of the EnMS. Energy-saving opportunities are to be given same priority as part of normal daily activities and decision-making of the organisation. Top management commitment must be communicated and made visible to the entire organisation through employee involvement activities such as empowerment, motivation, recognition, training, rewards and participation.

5.2 Energy Policy

Energy policy is a high-level statement conveying the overall intentions and directions of the organisation aligned with its long-term goals. It is established and documented by the top management. It shows top management commitment and support to energy performance improvement and serves as a guideline for setting targets, making decisions, and providing framework for actions.

The energy policy should clearly state organisation's energy priorities. ISO 50001 requires that the energy policy must demonstrate the commitments at least for (i) continual improvement of energy performance and the EnMS, (ii) availability of information and necessary resources to achieve its objectives and energy targets, and (iii) satisfy applicable legal and other requirements related to energy efficiency, energy use and energy consumption.

An energy policy is the foundation for developing an organization's EnMS through all phases of planning, implementation, operation, performance evaluation and improvement. It provides a framework for setting and reviewing objectives and targets. Policy document should be a brief statement so that members of the organization can readily understand and

apply to their work activities. The energy policy dissemination can be used as a means to manage organizational behaviour. The policy is required to well communicated within the organization, be available to interested parties and be periodically reviewed and updated as necessary. Every word used in energy policy is important and therefore, organization should avoid over committing and inclusion of those points in the energy policy which it cannot meet. A model energy policy is shown in Figure 3.4.

<i>Model Energy Policy</i> As an energy intense manufacturer of specialty glass, ABC Company strives to reduce its energy consumption and costs and promote the long-term environmental and economic sustainability of its operations. We are committed to: – Reduce energy use per unit of production in our manufacturing operations. – Ensure continual improvement in plant energy performance. – Deploy information and resources to achieve energy objectives and targets. – Uphold legal and other requirements regarding energy. – Consider energy performance improvements in design and modification of facilities, equipment, system, and processes – Effectively procure and utilize energy-efficient products and services. Managing Director: _____ Date: _____

Figure 3.4: Model Energy Policy

5.3 Organizational roles, responsibilities and authorities

Top management is required to form an Energy Management Team which will have the responsibility and authority mentioned under this clause to ensure effective implementation of the EnMS and for delivering energy performance improvement in accordance with ISO 50001 International Standard. It is also required to ensure that the responsibilities and authorities for relevant roles are assigned and communicated within the organization.

The team approach takes advantage of the diversity of skills and knowledge of individuals. Good practice is to have a cross-functional team from all sections of the organizations that can affect energy performance. This approach provides an effective mechanism to engage different parts of the organization in the planning, implementation, maintenance and improvement of the EnMS as well as of energy performance. Members of the team may change from time to time and should be based on defined roles (designations) rather than named individuals.

For smaller organizations, a single person might be enough, whereas large organizations will require this cross-functional team for effective planning and implementation of EnMS in different parts of the organization. Size of this team will depend on size and nature of the organization and available resources.

6 Planning

6.1 Actions to address risks and responsibilities

6.1.1 This clause covers the strategic part of planning where the organization considers the issues referred to in 4.1 and the requirements referred to in 4.2 and reviews the organization's activities and processes that can affect energy performance. While doing so, the organization is required to determine the risks and opportunities that need to be addressed to give assurance that the EnMS can achieve its intended outcome(s), including energy performance improvement; prevent or reduce undesired effects; and achieve continual improvement of the EnMS and energy performance.

By identifying risks and opportunities when planning the EnMS, an organization can anticipate potential scenarios and consequences so that undesired effects can be addressed before they occur. Similarly, favourable considerations and circumstances that can offer potential advantages or beneficial outcomes can be identified and pursued.

6.1.2 Under this clause, the organization is required to plan actions to address these risks and opportunities and how to integrate and implement the actions into its EnMS and energy performance processes as well as evaluate the effectiveness of these actions.

A concept diagram illustrating the strategic planning is shown in Figure 3.5.

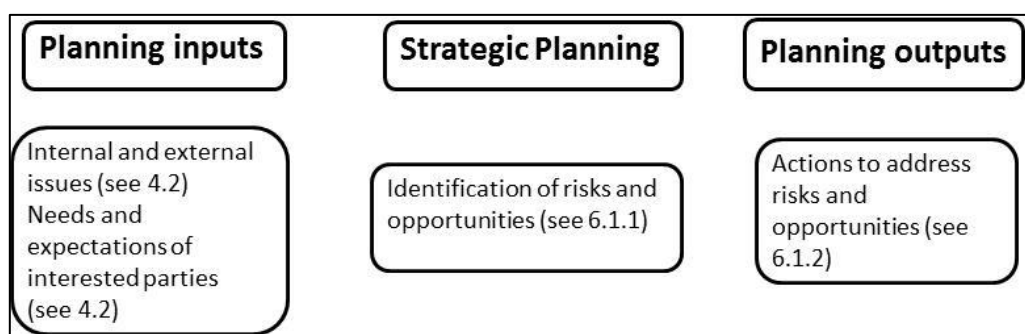


Figure 3.5 Strategic Planning to address risk and responsibilities

6.2 Objectives, energy targets and planning to achieve them

6.2.1 The data analysis and other information outputs from Energy Review are used in developing Energy Objectives and Targets. Setting objectives and targets provides the means for transforming policy into action. These are to be established for all relevant functions and levels of the organization.

6.2.2 Objectives are broader and normally covers whole of the organization / department / section and directly relevant to organization's energy policy. They could be quantifiable as well as qualitative.

Quantifiable objectives have targets for performance improvement (e.g. reduce electricity consumption by 3 % by the end of the year). Qualitative objectives relate to energy behaviour, cultural change etc. It is often possible to provide some quantitative values for qualitative objectives, through surveys or other similar mechanisms.

Similarly, energy targets are consistent with energy objective as they emerge from them and have more details. Targets should be SMART (specific, measurable if practical, achievable, relevant and time-based). It can be expressed in terms of the percentage improvement in energy performance or improvement in energy consumption or the EnPI with appropriate baseline period reference.

Factors which need to be considered while establishing and reviewing objectives and targets include legal requirements and other requirements, significant energy uses, opportunities to improve energy performance, financial, operational and business conditions, technological options and the views of interested parties.

6.2.3 Actions which are required to be taken to achieve the targets are known as Energy Management Action Plans. The energy management action plans are the road map to what is needed to achieve the energy objectives and targets. These typically arise from the energy performance improvement opportunities that were identified and prioritised as part of the energy review.

Top management is supposed to provide required resources for successful implementation of action plans. All action plans are required to show allocation of responsibility, resources required, time frame for completion, how to verify the improvement in energy performance (measurement method and other relevant details) and how to verify the result etc. An example showing consistency relationship between Energy Policy, Objective, Target and Action plan is shown in Table 3.1.

Table 3.1: Consistency Relationship between Policy, Objective, Target and Action Plan

Relevant portion in Energy Policy	Energy Objective	Energy Target	Action Plan					
			Details of action plan on what is to be done	By whom	Method of verification for energy performance improvement	Resources required	Time frame for completion	Method of verifying results
We shall improve our energy performance continually	Reduction in specific electrical Energy Consumption by end of July, 2019	Reduction of 10% in units consumed per MT of production as compared to 2017-18 by end of July, 2019	(i) All remaining inefficient lighting to be replaced with LED lighting	A.M. (Purchase) to procure and Maintenance In-charge to install	Power drawn by each type of existing lighting and of corresponding replacement	Finance for procuring all remaining inefficient lighting and manpower for doing it	Dec, 2018	Electrical submeter readings installed on lighting feeder & compressed air section and electricity bill stating total energy consumption for the month
			(ii) Replace pneumatic packing machines with mechanical packing machines	A.M. (Purchase) to procure and Maintenance In-charge to install and commission	No compressed air is required by packaging machines	Finance and manpower for Tendering, procuring, installation and commissioning of mechanical machines	July, 2019	
			(iii) Set screw air compressor pressure settings at optimum level to save power	Maintenance In-charge	Power drawn by each compressor during load before and after resetting of pressures	Manpower and skill for resetting the pressures for load and unload on all air compressors	Dec, 2018	
			(iv) Install VFDs at identified equipment having variable loads	A.M. (Purchase) to procure and Maintenance In-charge to install	Air compressor does not run in unload mode	Finance and manpower for Tendering, procuring, installation and commissioning of VFDs	April, 2019	

6.3 Energy review

To improve energy performance, it is necessary to understand how, why, and where energy is being consumed and to identify where opportunities to improve exist.

The energy review is the analytical part of tactical energy planning process (refer Figure 5.6). The purpose of the energy review is to obtain an overall picture of an organisation's energy use, patterns of use of each energy source, consumption trends, energy performance, variables affecting energy consumption (say production), opportunities for savings, and the resources required in terms of manpower, time and investments.

One of the important activities of energy review is to identify significant energy uses (SEUs) so that areas using more energy and/or having more potential for energy saving and/or both can be focused and planned accordingly. SEUs can be defined depending on the needs of the organization, such as by facility (e.g. warehouse, factory, office), by process or system (e.g. lighting, steam, transport, electrolysis, motor-driven) or equipment (e.g. motor, boiler). Once identified, the management and control of SEUs are an integral part of the EnMS.

Energy review is required to be updated at defined interval (at least annually) or when there are major changes in the energy scenario of the organization. The various steps involved in carrying out energy review are illustrated in Figure 5.6.

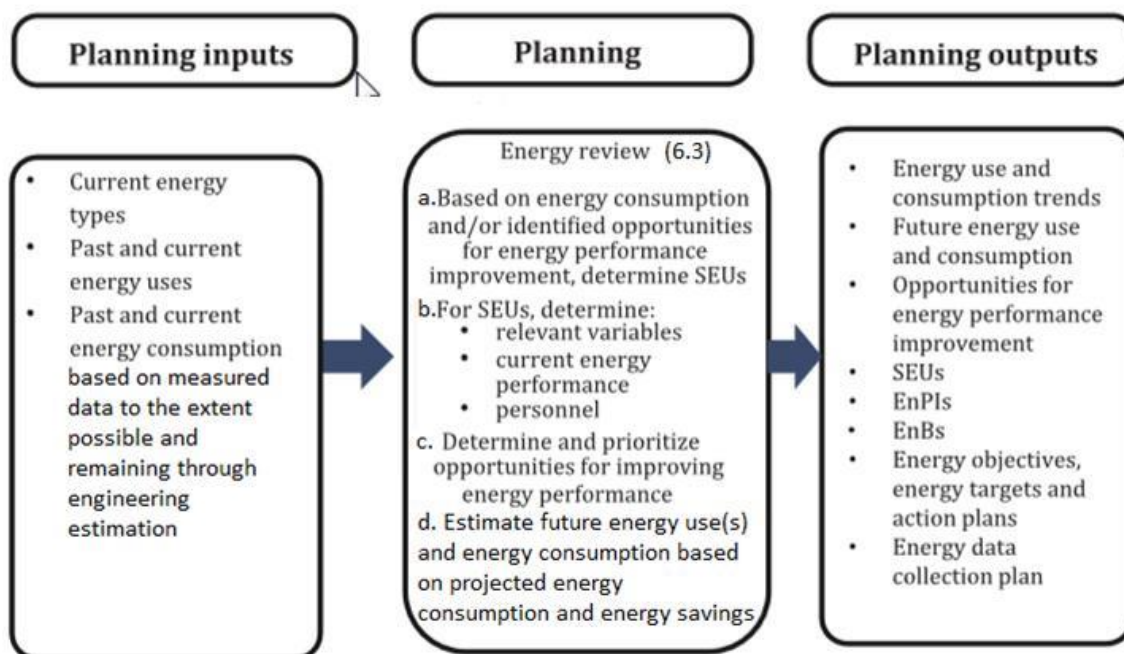


Figure 3.6: Energy Review

Steps in conducting Energy Review

1. Collect data on energy use for past 12/24 months
2. Analyse past and current energy use with relevant drivers (e.g. production)
3. Identify and challenge each SEUs (based on energy use and consumption)
(If measured data on energy consumption are not available, then, estimate using actual power drawn and hours of operation)
4. Identify variables affecting energy consumption and effect on SEUs
5. Determine current performance and baseline of identified SEUs
6. Identify and prioritize opportunities for improvement
7. Estimate future energy used based on projected production and expected energy saving which may result from implementation of energy conservation measures.
8. Agree objectives, energy targets and action plans.

6.4 Energy Performance Indicators

Energy review provides the information and data needed to establish EnPIs. EnPI is a “ruler” that is used to compare energy performance before (reference EnPI value) and after (resultant or current EnPI value) the implementation of action plans and other actions. The difference between the reference value and the resultant value is a measure of a change in energy performance.

EnPI helps turn energy data into useful information for top management. Types and examples of EnPIs are as follows:

- Simple energy consumption in kWh or kcal (in total or breakdown by energy use or by facility or by equipment)
- Simple ratios like energy consumption per time, or per unit of floor area or per unit of production
- Statistical model including liner or non-linear regression

Where the organization has data indicating that relevant variables significantly affect energy performance, the organization shall consider such data to establish appropriate EnPI(s). The methodology the organization is going to adopt on this matter and updating of EnPIs needs to be maintained as documented information. EnPI value(s) shall be reviewed and compared to their respective baseline value(s) (EnB) to assess energy performance and improvements, and need to be retained as documented information. Comparing energy performance between the baseline period and the reporting period involves calculating the difference in the value of EnPI between the two periods. The Figure 5.7 illustrates the simple case where direct measurement of energy consumption is used as EnPI and the energy performance is

compared between the baseline period and the reporting period. It also shows whether target (in case it was set) has been achieved or not.

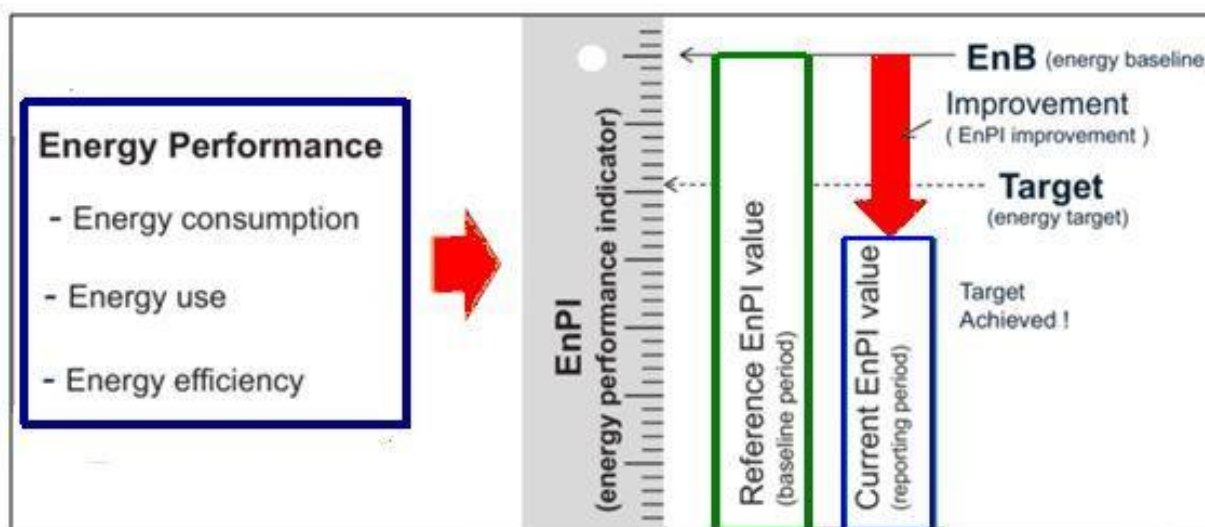


Figure 3.7: Energy Performance Indicator

With passage of time and maturity of EnMS, there should be increase in the number of EnPIs through indepth penetration (from whole organization level to facility to process/system-wise to individual equipment-wise).

6.5 Energy baseline

One of the main requirements of the ISO 50001 standard is to have continual improvement in energy performance of the organization, and to find out improvement, one has to have some base to compare with. This is what is known as “Energy Baseline” which is defined as the quantitative reference or references providing a basis of comparison of energy performance. Energy Review provides the information and data needed to establish the energy baseline.

The energy baseline is the reference for measuring energy performance over time. The type of energy baseline will depend on specific purpose of the Energy Performance Indicator (EnPI) and can be established at the facility, system, process, or equipment level. The energy baseline can be expressed as a mathematical relationship of energy performance as a function of relevant variables; an engineering model; a simple ratio; or simple consumption data (if there are no relevant variables).

Baseline is always pertaining to a period which is known as baseline period. This period should be representative of one complete cycle of the variations in the organizational operation like seasonal fluctuations in production in case of industries; occupancy in case of hotels; temperature & humidity in case of air conditioning in buildings etc. In all such cases, the baseline could be considered as one year. When determining energy performance improvement, the data needs to represent the same period as the baseline.

In almost all the cases, energy consumption is affected by relevant variables and these variables will be different in baseline period and the reporting period for which improvement is to be determined. Where the organization has data indicating that relevant variables significantly affect energy performance, the organization shall carry out normalization of the EnPI value(s) and corresponding EnB(s). Depending on the nature of the activities, normalization can be a simple adjustment, or a more complex procedure.

In order to do “apple to apple comparison” and to correctly assess the improvement made in energy performance, some adjustments in baseline may be required in certain cases. These cases could be one or more of the followings:

- a) where current EnPIs, the organizational boundaries and the energy baselines are no longer appropriate and effective to reflect organizations energy use and consumption, or
- b) there have been major changes to the process, operational patterns, or energy systems, (for example steam turbine is installed to generate electricity between baseline period and reporting period which will change the entire energy including fuel scenario of the organization) or
- c) according to a predetermined method like ‘normalization’ in PAT, where adjustment is made in the reporting period energy consumption due to changes in relevant variables or Static factors.

6.6 Planning for collection of energy data

Data are critically important in monitoring and analyzing key characteristics as identified under clause 9.1.1. Planning for which data to collect (minimum is given in the standard), how to collect them and how often to collect them forms the Energy Data Collection Plan which will depend upon the size and complexity of organization, its resources and its monitoring and measurement equipment. This Plan needs to be reviewed at defined intervals and updated as appropriate. The measuring equipment used for monitoring energy consumption and performance for operational decisions should be accurate, consistent and periodically calibrated.

7 Support

7.1 Resources

Under this clause, the organization is required to determine and provide the resources needed for the establishment, implementation which can include human resources, financial resources. specialized skills, technology, data collection infrastructure etc.

7.2 Competence

This is the responsibility of organization to ensure that all people working under its control and which can affect its energy performance are competent on the basis of appropriate education, training, skills and experience and takes necessary action like the provision of training to, the mentoring of, or the reassignment of currently employed persons; or the hiring or contracting of competent persons etc., to acquire the necessary competence and evaluate the effectiveness of action taken as well as retain appropriate documented information as evidence of competence.

Training is one of the many methods for achieving competency. EnMS team members should be encouraged to continually develop, maintain and improve their knowledge, skills and expertise. Organization can also consider certification course like BEE's course for Certified Energy Auditor/Manager or Lead Auditor course for ISO 50001 etc., to improve their competence level.

Competence requirements need be appropriate to the function, level and role of persons (including top management) doing work, which affects energy performance and the EnMS. Competence requirements are determined by the organization.

7.3 Awareness

Organization needs to ensure that every one working for it (regular employees, contract workers, security staff, helpers etc.) is aware of importance of conformity to energy policy and EnMS requirements; his/her roles, responsibilities and authorities in achieving the requirements of EnMS; benefits of improved energy performance as well as impact of their activities in achieving the same etc. Table 5.2 shows a sample training plan.

Table 3.2: Sample Training Plan

Type of Training	Participants
EnMS Awareness	All who are working under the control of organization
EnMS Implementation Training	Middle Management /Energy Management Team
EnMS Internal Auditor (IA) Training	Energy Management Team/Anyone interested in conducting Internal Audit (However, their competency needs to be ensured before they are allowed to conduct IA)
Training related to control of SEU	All personnel related to SEUs

7.4 Communication

Good internal and external communication is essential to managing change. It keeps personnel informed of energy management activities, incentives, and successes, which strengthens commitment and participation. Multiple channels of communication, whether

verbal or nonverbal can be used such as meetings, videos, briefings, e-mails, posters, memos, circulars etc. The organization is required to determine the internal and external communications relevant to the EnMS, including on what it will communicate; when to communicate; with whom to communicate, how to communicate and who communicates. However, when establishing its communication process (es), the organization shall ensure that information communicated is consistent with information generated with the EnMS and is dependable.

Organization is required to implement a suggestion scheme with incentives and rewards for good suggestions that can be implemented to stimulate interest and participation of all those who are working under the control of the organization.

7.5 Documented information

7.5.1 General

Documented information is defined as the information required by controlling and maintaining by an organization and the medium on which it is contained. It can be in any format and media, and from any source. Also, it can refer to the management system, including related processes; information created in order for the organization to operate (documentation); and evidence of results achieved. Thus, in this new ISO version, the documented information has included document(s), documentation as well as records of previous version in single phrase.

Documentation enables communication of intent and consistency of action. Its use contributes to achievement of conformity to requirements of the standard and provides objective evidence thereof. However, generation of documentation should not be an end in itself, but it should be a value-adding activity. The extent of documented information for an EnMS can differ from one organization to another due to the size of organization and its type of activities, processes, products and services; the complexity of processes and their interactions; and the competence of persons working therein.

A certain amount of documented information is required in the EnMS. Minimum (mandatory) documented information) as required by the standard under various clauses (clause numbers are mentioned in the bracket) are: Scope and Boundaries of the EnMS (4.3); Energy Policy (5.2); Energy Objective and Targets (6.2.2); Action Plans for achieving energy objectives and targets (6.2.3); Methodology and criteria used to develop the energy review (6.3); energy review results (6.3); method for determining and updating EnPIs (6.4); EnPIs Values (6.4); EnB(s), relevant variable data and modifications to EnB(s) (6.5); data to be collected and retained (6.6); details on measurement, monitoring and other means of establishing accuracy and repeatability (6.6); evidence of competence (7.2); external origin (7.5.3); operational planning and control (8.1); design activities (8.2); results of the investigation and response to significant deviation (9.1.1); results from monitoring and measurements (9.1.1); results of the evaluation of compliance and any action taken (9.1.2); evidence of the implementation of the audit programs and the audit results (9.2.2); evidence

of the results of management reviews (9.3.4); and nature of nonconformities and subsequent action taken as well as on results of any corrective action (10.1).

Documented information for whom the word “consider” has been used in the standard means it is necessary to think about the topic but it can be excluded. There is only one such documented information and it is on comments and suggestions received for improvement (7.4). Here, the organization is required to implement the suggestion scheme but can decide whether to include the comments and suggestions received as documented information in its EnMS or not.

7.2. Creating and Updating

This clause required organizations to take appropriate action while creating and updating documented information with respect to their identification and description (e.g. a title, date, author or reference number); format (e.g. language, software version, graphics) and media (e.g. paper, electronic) as well as review and approval for suitability and adequacy.

7.3. Control of documented information

There is no mandatory procedure that needs to be developed as documented information as per the standard. However, organization can still develop certain procedures as documented information for the convenience of all, especially if ISO management systems are new to the organization. Procedures which can be developed by organization in such a situation can include procedure on Documented Information Control, Internal Audit, Management Review, Nonconformity and Corrective Action, Communication, Identification of Competency, Skill & Training, and Significant Deviation.

Correct identification of the EnMS documents is crucial to ensure that the most up-to-date documents are in use, that they can be easily located, and that obsolete documents are removed from the points of use. Documented information required by the EnMS and by this document shall be controlled to ensure that it is available and suitable for use, where and when it is needed; is adequately protected (e.g. from loss of confidentiality, improper use, loss of integrity). For the control of documented information, the organization is required to address certain activities, as applicable like distribution, access, retrieval and use; storage and preservation, including preservation of legibility; control of changes (e.g. version control); and retention and disposition.

Any documented information, once developed for the EnMS (including technical documents wherever appropriate) as well as external documents which have been generated outside of the organization, need to be controlled. For this purpose, organization is required to implement a procedure where the complete process mentioned under this clause of the standard will be followed. Some examples of documents of external origin are laws/acts like Energy Conservation Act, 2001; ECBC 2007; Electricity Act, 2003; various standards being used by organization including ISO 50001, important technical documents including equipment manuals prepared by OEMs etc.

8. Operation

8.1 Operational planning & control

This involves examination of how significant energy uses are operated and maintained in comparison with energy-efficient practices. Best practices or criteria for operation and maintenance are developed, ensured that these practices are routinely followed, people responsible for following these practices are well communicated about these, and keeping documented information to the extent necessary to have confidence that the processes have been carried out as planned.

Under this clause, the organization is required to control planned changes and review the consequences of unintended changes, taking actions to mitigate any adverse effects, as necessary. The organization is also required to ensure that outsourced SEUs or processes related to SEUs are controlled.

Although not mandatory, it is a good practice to have documented information on operation and maintenance practices related to energy. These include work instructions, standard operating procedures (SOPs), work flow diagrams etc.

8.2 Design

The design activity associated with energy-saving and operation control presents one of the best opportunities to improve energy performance of new facilities, extensions to existing facilities, new or modified production process, upgrades, refurbishment, change of use and design. While doing so, organization should consider improved technologies, alternative energy such as renewable or less polluting types of energy options, best available energy efficient techniques, practices and emerging trends.

It is much better to design and implement these projects properly the first time round rather than to carry out upgrades or retrofits later. The costs of incorporating energy efficiency measures during the design stages are much lower and the benefits of doing so are greater than implementing as changes later during the operation stage. This approach can avoid frequent barriers to appropriate energy performances such as oversized equipment, over specified systems, and the use of inefficient technologies. Where applicable, the results of the energy performance consideration shall be incorporated into specification, design and procurement activities.

It is possible that equipment and systems may operate at partial or variable load for significant periods of time and therefore, it should be considered during the design, procurement and commissioning phases of the project.

8.3 Procurement

Procurement is an opportunity to improve energy performance through the use of more efficient products and services. It is also an opportunity to work with the supply chain and influence its energy behaviour.

Procurement policy of the organization should always consider energy implications while purchasing energy services, products, equipment and even purchase of energy itself. Also, while purchasing these, one should consider all costs for their expected life cycle. These costs include capital cost including taxes and duties, installation and commissioning cost, energy cost, maintenance cost, lubricant cost, operating manpower cost, disposal cost etc.

This clause of the standard calls organization to establish and implement the criteria for assessing energy use, consumption and efficiency over planned or expected operating lifetime when procuring energy using products, equipment and services which are expected to have a significant impact on the organization's energy performance. This can include life cycle costs as mentioned above; expected impact on the overall system energy performance (e.g. the energy efficiency of a pumping system at the planned system operating conditions); performance at part load and under fluctuating loads; certification from reputed agencies or from other third parties.

Even while purchasing energy, organization should consider the opportunities for reducing cost in purchasing electricity and fuels. Factors which can be considered while evaluating purchase of energy should include quantity (to check for bulk discounts for more quantity or penalty for less quantity), quality (voltage fluctuation, harmonic quality etc), price or rates, contract period, reliability, flexibility etc.

Examples of Energy Service providers are energy consultants, energy service companies (ESCOs), energy service providers, energy auditors, energy related trainers etc. Energy services can include annual maintenance services (AMC) and contracts; equipment and technology advice; project design, construction and commissioning; vehicle and transport services and energy or utility suppliers.

Many times, energy performance of an equipment or system is adversely affected due to fact that the organization had not defined and documented energy purchasing specifications while placing the purchase order and hence, wherever applicable, the organization shall define and communicate specifications for ensuring the energy performance of procured equipment and services as well as for the purchase of energy.

9. Performance evaluation

9.1 Monitoring, measurement, analysis and evaluation of energy performance and the EnMS

9.1.1 General

There are a number of key characteristics that an organisation should monitor, measure and analyse to be aware of its energy performance at regular intervals. To know whether performance is improving as planned, organisation needs to monitor minimum of the key

characteristics mentioned in the standard. Organization is also required to determine the methods for monitoring, measurement, analysis and evaluation, as applicable, to ensure valid results; when the monitoring and measurement shall be performed; and when the results from monitoring and measurement shall be analysed and evaluated.

The organization is supposed to evaluate its energy performance and the effectiveness of the EnMS as well as improvement in energy performance by comparing EnPI value(s) against the corresponding energy baselines.

The organization is also required to investigate and take appropriate actions to significant deviations in energy performance which could be on negative side i.e. adverse, or positive side. It is important to investigate deviations on the positive side also so as to ensure their repetition every time.

9.1.2 Evaluation of Compliance with legal requirements and other requirements

The organization should determine if processes for evaluating compliance with legal and other requirements (which have already been identified and planned under clause 4.2 of the standard) are in place and whether they can be adapted to address the needs of the EnMS. This process is supposed to be carried out at planned frequency and documented information is to be retained.

9.2 Internal audit

9.1.1 An internal audit of an EnMS is an objective, systematic review of all or part of an organization's EnMS which is carried out at planned intervals. It must be remembered that internal audit of EnMS is a 'fact finding' exercise and not a 'fault finding' exercise and therefore, auditor should not look out for only finding faults. The facts which need to be found out through Internal Audit are whether the EnMS improves energy performance; conforms to the organization's own requirements for its EnMS as well as to its energy policy, objectives and energy targets established by the organization, the requirements of the ISO 50001 standard and is effectively implemented and maintained. Of course, during this fact-finding exercise, auditor may come across certain non-conformities which are required to be highlighted in the internal audit reporting.

During an internal audit, the auditors' interview relevant personnel, observe operational activities, review documents, and examine records and data.

9.1.2 Under this clause, organization is required to plan, establish, implement and maintain (an) audit programme(s) as per the details mentioned in the standard.

Internal audit can be carried out more frequently for areas (i) that influence energy performance substantially, (ii) where important nonconformities (NCs) have been identified in previous audits, (iii) that have experienced important changes and (iv) areas where important changes are being planned. Similarly, EnMS internal audits can be conducted less frequently for those areas that do not significantly impact energy performance or for

processes that have fewer Nonconformities from previous audits. However, it is suggested that all areas and processes should undergo internal audits annually for at least first two years of EnMS implementation.

9.3 Management review

9.3.1 This is the key responsibility of top management focused on ensuring the on-going suitability, adequacy, effectiveness and alignment with the strategic direction of the organization. Management review highlights the top management on the positive outcomes as well as the weaknesses, in order to provide effective recommendations for improvements.

Management review is conducted at planned frequency, which should be at least once a year, within which corrective action can be taken and appropriate systems adjustments can be made. All records pertaining to management review meetings are required to be maintained.

9.3.2 Minimum Agenda for the management review meeting is a status regarding action from previous management review, changes in internal and external issues and associated risks opportunities relevant to EnMS, Internal as well as external audit results, existing energy policy appropriateness in the present circumstances, review of the compliance of legal and other requirements, opportunities for continual improvement and competence, monitoring and measurement results, status of nonconformities and corrective actions etc.

9.3.3 Management review is also supposed to review in depth analysis of the extent to which objectives and energy targets have been met; energy performance and energy performance improvement based on monitoring and measurement results including the EnPI (s) and status of the action plans.

9.3.4 It is subsequently the task of top management to take decision related to continual improvement opportunities and need to changes in the EnMS which will indicate the organization's energy performance in complete and best possible manner, how improvement in energy performance is progressing, any changes in the energy policy, EnPIs, EnB(s), objectives, targets and action plans, allocation of resources, the improvement of competence, awareness and communication etc.

10 Improvement

10.1 Nonconformity and corrective action

Non fulfillment of a requirement is Nonconformity. This requirement could be of ISO 50001 standard, of the EnMS which organization has prepared, or of its operation control etc. In simple words any deviation from specified norms is Nonconformity.

When a nonconformity is detected, the first step is to take appropriate action to resolve the immediate situation and it is known as correction, e.g. reduction in air pressure to a level

affecting the plant operation due to dirty filter in an air compressor is a nonconformity and to clean or replace the filter is the correction which will restore the correct air pressure, i.e. nonconformity will get eliminated.

However, taking correction may not be enough and nonconformity may reoccur until and unless, investigation is carried out to find out its root cause and then, action is taken to eliminate the root cause of the problem. This is known as the corrective action. In other words, action taken to prevent reoccurrence of a detected nonconformity is corrective action. In the above example of compressed air, corrective action would be to determine why filter got dirty and to address the root cause to prevent its reoccurrence. For example, filter might be dirty due to its location in a dusty room and relocating it in a cleaner room or outside the room will be the corrective action.

Taking correction and corrective action should not be confined to internal or external audits only as normally perceived and carried out. Several other sources like results of evaluations of compliance reviews, failure to reach specified targets in monitoring and measurement processes, failure to comply with operational control procedures, repeated significant deviations, routine inspection of the plant etc should also be considered for raising non-conformities. In other words, any activity not happening as per norms in day today activity of the organization is also nonconformity and hence, Nonconformity can be raised on it calling for correction and corrective action to take place.

Addressing NCs should be seen as a part of continual improvement process and these give the opportunities to an organization for making improvement. Corrective actions are so important for the organization that their status is reviewed by top management in every Management Review Meeting.

10.2 Continual improvement

As committed in the energy policy, the organization is required to continually improve the suitability, adequacy and effectiveness of the EnMS and also continually improve its energy performance. Demonstrating continual energy performance improvement across the scope and within the boundaries of the EnMS does not mean all EnPI values improve. Some EnPI values improve, and others do not; but across the scope of the EnMS, the organization demonstrates energy performance improvement.

Summary

From time to time, organization needs to review its entire EnMS journey as to where it wanted to be, what was the situation, what was planned, what needed to be done, whether it has reached there and ultimately what next to improve continually as shown in Figure 3.8.

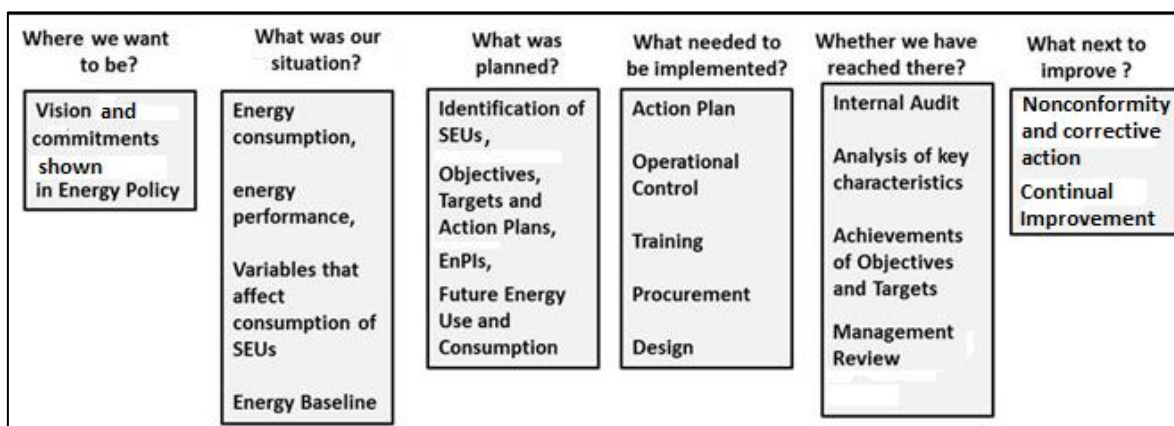


Figure 3.8: EnMS Journey Review

Module 2

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1. FUELS AND COMBUSTION

1.1. Introduction to Fuels

The various type of fuels like liquid, solid and gaseous fuels are available for firing in boilers. The selection of right type of fuel depends on the various factors such as availability, storage, handling, pollution and landed cost of fuel.

The knowledge of the fuel properties helps in selecting the right fuel for the right purpose and efficient use of the fuel. The following characteristics, determined by laboratory tests, are generally used for assessing the nature and quality of fuels.

1.2. Properties of Liquid Fuels

Density

Density is the ratio of the mass of the fuel to the volume of the fuel at a reference temperature typically 15°C. The knowledge of density is useful for quantity calculations and assessing ignition quality. The unit of density is kg/m³.

Specific gravity

This is defined as the ratio of the weight of a given volume of oil to the weight of the same volume of water at a given temperature. The measurement of specific gravity is generally made by a hydrometer. The density of fuel, relative to water, is called specific gravity. The specific gravity of water is defined as 1. Since specific gravity is a ratio, there are no units.

Higher the specific gravity, higher is the heating value. Its main use is in calculations involving weights and volumes. The specific gravity of various fuel oil is given in Table 1.1.

Table 1.1: Specific gravity of various fuel oils

Fuel Oil	L.D.O Light Diesel Oil	Furnace oil	L.S.H.S Low Sulphur Heavy Stock
Specific Gravity	0.85-0.87	0.89-0.95	0.88-0.98

Viscosity

The viscosity of a fluid is a measure of its internal resistance to flow. Viscosity depends on temperature and decreases as the temperature increases. Any numerical value for viscosity has no meaning unless the temperature is also specified. Viscosity is measured in Stokes / Centistokes. Sometimes viscosity is also quoted in Engler, Saybolt or even Redwood. Each type of oil has its own temperature-viscosity relationship.

The measurement of viscosity is made with an instrument called as viscometer

Viscosity is the most important characteristic in the fuel oil specification. It influences the degree of pre-heat required for handling, storage and satisfactory atomization. If the oil is too viscous it may become difficult to pump, hard to light the burner and operation may become erratic. Poor atomization may result in the formation of carbon deposits on the burner tips or on the walls. Pre-heating is necessary for proper atomization.

Flash Point

The flash point of a fuel is the lowest temperature at which the fuel can be heated so that the vapour gives off flashes momentarily when an open flame is passed over it. Flash point for furnace oil is 66°C.

Pour Point

The pour point of a fuel is the lowest temperature at which it will pour or flow when cooled under pre scribed conditions. It is a very rough indication of the lowest temperature at which fuel oil is readily pumpable

Specific Heat

Specific heat is the amount of kCals needed to raise the temperature of 1 kg of oil by 1°C. The unit of specific heat is kCal/kg°C. It varies from 0.22 to 0.28 depending on the oil specific gravity. The specific heat determines how much steam or electrical energy it takes to heat oil to a desired temperature. Light oils have a low specific heat, where as heavier oils have a higher specific heat.

Calorific Value

The calorific value is the measurement of heat or energy produced, and is measured either as gross calorific value or net calorific value. The difference being the latent heat of condensation of the water vapour produced during the combustion process. Gross calorific value assumes all vapour produced during the combustion process is fully condensed. Net calorific value assumes the water leaves with the combustion products without fully being condensed. Fuels should be compared based on the net calorific value.

The calorific value of coal varies considerably depending on the ash, moisture content and the type of coal while calorific value of fuel oil is much more consistent. The typical Gross Calorific Values of some of the commonly used liquid fuels are given below:

<u>Fuel Oil</u>	<u>Calorific Value (kCal/Kg)</u>
Kerosene	-11,100
Diesel Oil	-10,800
L.D.O	-10,700
Furnace Oil	-10,500
LSHS	-10,600

The following conversion formula shows the difference between GCV and NCV.

$$\text{GCV} = \text{NCV} + 584 ((9\text{H}_2\% + \text{M}\%) / 100)$$

Where,

GCV= Gross calorific value of fuel, kcal/kg

NCV = Net calorific value of fuel, kcal/kg

H₂%= Hydrogen % by weight present in the fuel

M% = Moisture % by weight present in the fuel

584 = Latent heat corresponding to partial pressure of water vapour,

kCal/kg

Sulphur

The amount of sulphur in the fuel oil depends mainly on the source of the crude oil and to a lesser extent on the refining process. The normal sulfur content for the residual fuel oil (heavy fuel oil) is in the order of 2-4%.

Typical figures are:

Fuel oil	Percentage of Sulphur
Kerosene	0.05 - 0.2
Diesel Oil	0.3 -1.5
L.D.O	0.5 – 1.8
Heavy Fuel Oil	2.0 – 4.0
LSHS	< 0.5

The main disadvantage of sulphur is the risk of corrosion by sulphuric acid formed during and after combustion, and condensing in cool parts of the chimney or stack, air pre heater and economiser.

Ash Content

The ash value is related to the inorganic material in the fuel oil. The ash levels of distillate fuels are negligible. Residual fuels have more of the ash-forming constituents. These salts may be compounds of sodium, vanadium, calcium magnesium, silicon, iron, aluminum, nickel, etc.

Typically, the ash value is in the range 0.03-0.07 %. Excessive ash in liquid fuels can cause fouling deposits in the combustion equipment. Ash has erosive effect on the burner tips, causes damage to the refractories at high temperatures and gives

rise to high temperature corrosion and fouling of equipments.

Carbon Residue

Carbon residue indicates the tendency of oil to deposit a carbon acetous solid residue on a hot surface, such as a burner or injection nozzle, when its vaporizable constituents evaporate. Residual oil contain carbon residue ranging from 1 percent or more.

Water Content

Water content of furnace oil when supplied is normally very low as the product at refinery site is handled hot and maximum limit of 1% is specified in the standard.

Water may be present in free or emulsified form and can cause damage to the inside furnace surfaces during combustion especially if it contains dissolved salts. It can also cause spluttering of the flame at the burner tip, possibly extinguishing the flame and reducing the flame temperature or lengthening the flame.

Typical specification of fuel oil is summarized in the Table1.2.

Table 1.2: Typical specification of fuel

Properties	Fuel Oils		
	Furnace Oil	LS.H.S.	L.D.O.
Density (Approx. g/cc at 15 ⁰ C)	0.89-0.95	0.88-0.98	0.85-0.87
Flash Point (⁰ C)	66	93	66
Pour Point (⁰ C)	20	72	12 (Winter) 18 (Summer)
G.C.V. (kcal/kg)	10,500	10,600	10,700
Sediment, % Wt. Max.	0.25	0.25	0.1
Sulphur Total, % Wt. Max.	Up to 4.0	Up to 0.5	Up to 1.8
Water Content, % Vol. Max.	1.0	1.0	0.25
Ash % Wt. Max.	0.1	0.1	0.02

Storage of Fuel oil

It can be potentially hazardous to store furnace oil in barrels. A better practice is to store it in cylindrical tanks, either above or below the ground. Furnace oil, that is delivered, may contain dust, water and other contaminants.

The sizing of storage tank facility is very important. A recommended storage estimate is to provide for at least 10days of normal consumption. Industrial heating fuel storage tanks are generally vertical mild steel tanks mounted above ground. It is

prudent for safety and environmental reasons to build bund walls around tanks to contain accidental spillages.

As a certain amount of settlement of solids and sludge will occur in tanks over time, cleaning should be carried out at regular intervals-annually for heavy fuels and every two years for light fuels. A little care should be taken when oil is decanted from the tanker to storage tank. All leaks from joints, flanges and pipelines must be attended at the earliest. Fuel oil should be free from possible contaminants such as dirt, sludge and water before it is fed to the combustion system.

LOSS OF EVEN ONE DROP OF OIL EVERY SECOND CAN COST OVER 4000 LITRES A YEAR

Removal of Contaminants

Furnace oil arrives at the factory site either in tank lorries by road or by rail. Oil is then decanted into the main storage tank. To prevent contaminants such as rags, cotton waste, loose nuts or bolts or screws entering the system and damaging the pump, coarse strainer of 10 mesh size (not more than 3 holes per linear inch) is positioned on then try pipe to the storage tanks.

Progressively finer strainers should be provided at various points in the oil supply system to filter away finer contaminants such as external dust and dirt, sludge or free carbon. It is advisable to provide these filters in duplicate to enable one filter to be cleaned while oil supply is maintained through the other.

The Figure1.1 gives an illustration of the duplex system of arrangement of strainers.

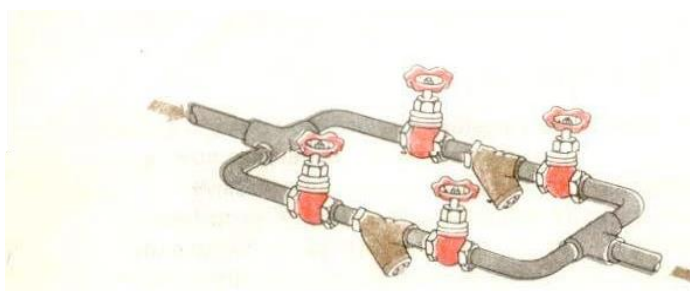


Figure1.1: Duplex arrangement of strainers in a pipeline

The Table 1.3 gives sizing of strainers at various locations.

Table 1.3: Sizing of strainers at various locations

Location	Strainer Sizes	
	Mesh	Holes / Linear inch
Between rail / tank lorry decanting point and main storage tank	10	3

Between service tank and pre-heater	40	6
Between pre-heater and burner	100	10

Pumping

Heavy fuel oils are best pumped using positive displacement pumps, as they are able to get fuel moving when it is cold. A circulation gear pump running on LDO should give between 7000-10000 hours of service. Diaphragm pump shave a shorter service life, but are easier and less expensive to repair. A centrifugal pump is not recommended, because as the oil viscosity increases, the efficiency of the pump drops sharply and the horse power required increases. Light fuels are best pumped with centrifugal or turbine pumps. When higher pressures are required, piston or diaphragm pumps should be used.

Storage Temperature and Pumping Temperature

The viscosity of furnace oil and LSHS increases with decrease in temperature, which makes it difficult to pump the oil. At low ambient temperatures (below 25 °C), furnace oil is not easily pumpable. To circumvent this, preheating of oil is accomplished in two ways: a) the entire tank may be preheated. In this form of bulk heating, steam coils are placed at the bottom of the tank, which is fully insulated; b) the oil can be heated as it flows out with an outflow heater. To reduce steam requirements, it is advisable to insulate tanks where bulk heating is used.

Bulk heating may be necessary if flow rates are high enough to make outflow heaters of adequate capacity impractical, or when a fuel such as Low Sulphur Heavy Stock (LSHS) is used. In the case of out flow heating, only the oil, which leaves the tank, is heated to the pumping temperature. The out flow heater is essentially a heat exchanger with steam or electricity as the heating medium.

Temperature Control

Thermostatic temperature control of the oil is necessary to prevent overheating, especially when oil flow is reduced or stopped. This is particularly important for electric heaters, since oil may get carbonized when there is no flow and the heater is on. Thermostats should be provided at a region where the oil flows freely into the suction pipe. The temperature at which oil can readily be pumped depends on the grade of oil being handled. Oil should never be stored at a temperature above that necessary for pumping as this leads to higher energy consumption.

1.3. Properties of Coal

Coal Classification

In general there are three main types of coal: anthracite, bituminous, and lignite, but no clear-cutline exists between them and coal is further classed as semi anthracite, semi bituminous, and sub bituminous. Anthracite is the oldest form of coal, geologically speaking. It is a hard coal composed mainly of carbon with little volatile content and practically no moisture. Lignite is the youngest form of coal, composed

mainly of volatile matter and moisture content with low fixed carbon content. Fixed carbon refers to carbon in its free state, not combined with other elements. Volatile matter refers to those combustible constituents of coal that vaporize when coal is heated.

The chemical composition of coal has a strong influence on its combustibility. The properties of coal are broadly classified as

- Physical properties
- Chemical properties

Physical Properties Heating Value:

The heating value of coal varies from country to country and even from mine to mine within the same country. The typical GCVs for various coals are given in the Table14.

Table 1.4: GCVs for various coals

Parameter	Lignite	Indian Coal	Indonesian Coal	South African Coal
GCV (kcal/kg)	6,300	4,000	5,500	6,000

Analysis of Coal

There are two methods: the ultimate analysis splits up the fuel in to all its component elements, solid or gaseous; and the proximate analysis determines only the fixed carbon, volatile matter, moisture and ash percentages. The ultimate analysis must be carried out in a properly equipped laboratory by as killed chemist, but proximate analysis can be made with fairly simple apparatus.

Proximate Analysis

Proximate analysis indicates the percentage by weight of the Fixed Carbon, Volatiles, Ash, and Moisture Content in coal. The amounts of fixed carbon and volatile combustible matter directly contribute to the heating value of coal. Fixed carbon acts as a main heat generator during burning. High volatile matter content indicates easy ignition of fuel. The ash content is important in the design of the furnace grate, combustion volume, pollution control equipment and ash handling systems of a furnace. A typical proximate analysis of various coal is given in the Table1.5.

Table 1.5: Typical proximate analysis of various coal

Parameter	Indian Coal	Indonesian Coal	South African

Moisture	5.98	9.43	8.5
Ash	38.56	13.99	18
Volatile matter	20.70	29.79	23.28
Fixed Carbon	34.69	46.79	51.22

Significance of Various Parameters in Proximate Analysis

a) Fixed carbon:

Fixed carbon is the solid fuel left in the furnace after volatile matter is distilled off. It consists mostly of carbon but also contains some hydrogen, oxygen, sulphur and nitrogen not driven off with the gases. Fixed carbon gives a rough estimate of heating value of coal

b) Volatile Matter:

Volatile matters are the methane, hydrocarbons, hydrogen and carbon monoxide, and incombustible gases like carbon dioxide and nitrogen found in coal. Thus the volatile matter is an index of the gaseous fuels present. Typical range of volatile matter is 20 to 35%.

Volatile Matter

- Proportionately increases flame length, and helps in easier ignition of coal.
- Sets minimum limit on the furnace height and volume.
- Influences secondary air requirement and distribution aspects.

c) Ash Content:

Ash is an impurity that will not burn. Typical range is 0.5 to 40%.

Ash

- Reduces handling and burning capacity.
- Increases handling costs
- Affects combustion and boiler efficiency
- Causes clinkering and slagging

a) Moisture Content:

Moisture in coal must be transported, handled and stored. Since it replaces combustible matter, it decreases the heat content per kg of coal. Typical range is 0.5 to 10%.

Moisture

- Increases heat loss, due to evaporation and superheating of vapour
- Helps, to a limit, in binding fines.
- Aids radiation heat transfer.

b) Sulphur Content:

Typical range is 0.5 to 5% normally. Sulphur

- Affects clinkering and slagging tendencies
- Corrodes chimney and other equipment such as air heaters and economisers
- Limits exit flue gas temperature.

Chemical Properties Ultimate Analysis:

The ultimate analysis indicates the various elemental chemical constituents such as Carbon, Hydrogen, Oxygen, Sulphur, etc. It is useful in determining the quantity of air required for combustion and the volume and composition of the combustion gases. This information is required for the calculation of flame temperature and the flue duct design etc. Typical ultimate analyses of various coals are given in the Table 1.6.

Table 1.6: Ultimate analyses of various coals

Parameter	Lignite,%	Indian Coal,%	Indonesian
Moisture (Dry basis)	50	5.98	9.43
Mineral Matter	10.41	38.63	13.99
Carbon	62.01	41.11	58.96
Hydrogen	6.66	2.76	4.16
Nitrogen	0.60	1.22	1.02
Sulphur	0.59	0.41	0.56
Oxygen	19.73	9.89	11.88

Relationship Between Ultimate Analysis and Proximate Analysis

$$\begin{aligned}
 \%C &= 0.97C + 0.7(VM - 0.1A) - M(0.6 - 0.01M) \\
 \%H &= 0.036C + 0.086(VM - 0.1xA) - 0.0035M^2 (1 - 0.02M) \\
 \%N_2 &= 2.10 - 0.020 VM
 \end{aligned}$$

Where

$$\begin{aligned}
 C &= \% \text{ of fixed carbon} \\
 A &= \% \text{ of ash} \\
 VM &= \% \text{ of volatile matter} \\
 M &= \% \text{ of moisture}
 \end{aligned}$$

Storage, Handling and Preparation of Coal

Uncertainty in the availability and transportation of fuel necessitates storage and subsequent handling. Stocking of coal has its own disadvantages like build-up of inventory, space constraints, deterioration in quality and potential fire hazards. Other minor losses associated with the storage of coal include oxidation, wind and carpet loss. A 1% oxidation of coal has the same effect as 1% ash in coal, wind losses may account for nearly 0.5 – 1.0% of the total loss.

The main goal of good coal storage is to minimize carpet loss and the loss due to spontaneous combustion. Formation of a soft carpet, comprising of coal dust and soil causes carpet loss. On the other hand, gradual temperature build up in coal heap, on account of oxidation may lead to spontaneous combustion of coal in storage.

The measures that would help in reducing the carpet losses are as follows:

1. Preparing a hard ground for coal to be stacked upon.
2. Preparing standard storage bays out of concrete and brick

In process Industry, modes of coal handling range from manual to conveyor systems. It would be advisable to minimize the handling of coal so that further generation of fines and segregation effects are reduced.

Preparation of Coal

Preparation of coal prior to feeding in to the boiler is an important step for achieving good combustion. Large and irregular lumps of coal may cause the following problems:

1. Poor combustion conditions and inadequate furnace temperature.
2. Higher excess air resulting in higher stack loss.
3. Increase of unburnt in the ash.
4. Low thermal efficiency.

(a) Sizing of Coal

Proper coal sizing is one of the key measures to ensure efficient combustion. Proper coal sizing, with specific relevance to the type of firing system, helps towards even burning, reduced ash losses and better combustion efficiency.

Coal is reduced in size by crushing and pulverizing. Pre-crushed coal can be economical for smaller units, especially those which are stoker fired. In a coal handling system, crushing is limited to a top size of 6 or 4mm. The devices most commonly used for crushing are the rotary breaker, the roll crusher and the hammer mill.

It is necessary to screen the coal before crushing, so that only oversized coal is fed to the crusher. This helps to reduce power consumption in the crusher. Recommended practices in coal crushing are:

1. Incorporation of a screen to separate fines and small particles to avoid extra fine generation in crushing.
2. Incorporation of a magnetic separator to separate iron pieces in coal, which may damage the crusher.

The Table 1.7 gives the proper size of coal for various types of firing systems

Table 1.7: Proper size of coal for various types of firing systems

S. No.	Types of Firing System	Size (in mm)

1	Hand Firing (a) Natural draft (b) Forced draft	25-75 25-40
2	Stoker Firing (a) Chain grate i) Natural draft ii) Forced draft (b) Spreader Stoker	25-40 15-25 15-25
3	Pulverized Fuel Fired	75% below 75 micron*
4	Fluidized bed boiler	< 10 mm

*Micron = 1/1000mm

(b) Conditioning of Coal

The fines in coal present problems in combustion on account of segregation effects. Segregation of fines from larger coal pieces can be reduced to a great extent by conditioning coal with water. Water helps fine particles to stick to the bigger lumps due to surface tension of the moisture, thus stopping fines from falling through grate bars or being carried away by the furnace draft. While tempering the coal, care should be taken to ensure that moisture addition is uniform and preferably done in a moving or falling stream of coal.

If the percentage of fines in the coal is very high, wetting of coal can decrease the percentage of un burnt carbon and the excess air level required to be supplied for combustion. Table 1.8 shows the extent of wetting, depending on the percentage of fines in coal.

Table 1.8: Extent of wetting, depending on the percentage of fines in coal

Fines (%)	Surface Moisture (%)
10 - 15	4 - 5
15 - 20	5 - 6
20 - 25	6 - 7
25 - 30	7 - 8

(c) Blending of Coal

In case of coal lots having excessive fines, it is advisable to blend the predominantly lumped coal with lots containing excessive fines. Coal blending may thus help to limit the extent of fines in coal being fired to not more than 25%. Blending of different qualities of coal may also help to supply uniform coal feed to the boiler.

The proximate and ultimate analyses of various coals are given in Table 1.9 and 1.10.

Table 1.9: Proximate analysis of various coals

	Lecofines	Lignite	Indian Coall	Indian Coall	Indonesian Coal	South African Coal
Moisture (%)	9.92	49.79	5.98	4.39	9.43	8.5
Ash (%)	5.93	10.41	38.65	47.86	13.99	18
Volatile matter (%)	24.08	47.76	20.70	17.97	29.79	23.28
Fixed Carbon (%)	60.70	41.83	34.69	29.78	46.79	51.22

Table 1.10: Ultimate analysis of various coals

	Leco fines	Lignite	Indian Coall	Indian Coalll	Indonesian Coal
Moisture (%)	9.92	Dry basis	5.98	4.39	9.43
Mineral matter (%)	5.93	10.41	38.63	47.86	13.99
Carbon (%)	71.02	62.01	42.11	36.22	58.96
Hydrogen (%)	3.33	6.66	2.76	2.64	4.16
Nitrogen (%)	0.96	0.60	1.22	1.09	1.02
Sulphur (%)	0.55	0.59	0.41	0.55	0.56
Oxygen (%)	8.29	19.73	9.89	7.25	11.88
GCV(kCal/kg)	7242	6301	4000	3500	5500

1.4. Properties of Gaseous Fuels

Gaseous fuels in common use are liquefied petroleum gases (LPG), Natural gas, producer gas, blast furnace gas, coke oven gas etc. The calorific value of gaseous fuel is expressed in Kilocalories per cubic meter (kcal/Nm³) i.e.at normal temperature and pressure.

Calorific Value

Since most gas combustion appliances cannot utilize the heat content of the water vapour, gross calorific value is of little interest. Fuel should be compared based on the net calorific value. This is especially true for natural gas, since increased hydrogen content results in high water formation during combustion.

Typical physical and chemical properties of various gaseous fuels are given inTable1.11.

Table 1.11: Typical physical and chemical properties of various gaseous fuels

Fuel Gas	Relative Density	Higher Heating Value, kCal/Nm³	Air/Fuel ratio, m³ of air to m³ of Fuel	Flame Temp., °C	Flame Speed, m/s
Natural Gas	0.6	9350	10	1954	0.290
Propane	1.52	22200	25	1967	0.460
Butane	1.96	28500	32	1973	0.870

LPG

LPG is a predominant mixture of propane and Butane with a small percentage of unsaturates (Propylene and Butylene) and some lighter C₂ as well as heavier C₅ fractions. Included in the LPG range are propane (C₃H₈), Propylene (C₃H₆), normal and

iso-butane (C_4H_{10}) and Butylene (C_4H_8).

LPG may be defined as those hydrocarbons which are gaseous at normal atmospheric pressure, but may be condensed to the liquid state at normal temperature, by the application of moderate pressures. Although they are normally used as gases, they are stored and transported as liquids under pressure for convenience and ease of handling. Liquid LPG evaporates to produce about 250 times volume of gas.

LPG vapour is denser than air: butane is about twice as heavy as air and propane about one and a half times as heavy as air. Consequently, the vapour may flow along the ground and into drains sinking to the lowest level of the surroundings and be ignited at considerable distance from the source of leakage. Still air vapour will disperse slowly. Escape of even small quantities of the liquefied gas can give rise to large volumes of vapour / air mixture and thus cause considerable hazard. To aid in the detection of atmospheric leaks, all LPG's are required to be odorized. There should be adequate ground level ventilation where LPG is stored. For this very reason, LPG cylinders should not be stored in cellars or basements, which have no ventilation at ground level.

Natural Gas

Methane is the main constituent of Natural gas and accounting for about 95% of the total volume. Other components are: Ethane, Propane, Butane, Pentane, Nitrogen, Carbon Dioxide, and traces of other gases. Very small amounts of sulphur compounds are also present. Since methane is the largest component of natural gas, generally properties of methane are used when comparing the properties of natural gas to other fuels.

Natural gas is a high calorific value fuel requiring no storage facilities. It mixes with air readily and does not produce smoke or soot. It has no sulphur content. It is lighter than air and disperses in to air easily in case of leak. A typical comparison of carbon contents in oil, coal and gas is given in the table 1.12.

Table 1.12: Comparison of carbon contents in oil, coal and gas

	Fuel Oil	Coal	Natural Gas
Carbon	84	41.11	74
Hydrogen	12	2.76	25
Sulphur	3	0.41	-
Oxygen	1	9.89	Trace
Nitrogen	Trace	1.22	0.75
Ash	Trace	38.63	-
Water	Trace	5.98	-

1.5. Properties of Agro Residues

The use of locally available agro residues is on the rise. This includes rice husk, coconut shells, groundnut shells, Coffee husk, Wheat stalk etc. The properties of a few of them are given in the table1.13.

Table 1.13: Properties of Agro Residues

	DeoiledBran	PaddyHusk	SawDust	CoconutShell
Moisture	7.11	10.79	37.98	13.95
Ash	18.46	16.73	1.63	3.52
Volatile Matter	59.81	56.46	81.22	61.91
Fixed Carbon	14.62	16.02	17.15	20.62
Mineral Matter	19.77	16.73	1.63	3.52
Carbon	36.59	33.95	48.55	44.95
Hydrogen	4.15	5.01	6.99	4.99
Nitrogen	0.82	0.91	0.80	0.56
Sulphur	0.54	0.09	0.10	0.08
Oxygen	31.02	32.52	41.93	31.94
GCV(kCal/kg)	3151	3568	4801	4565

1.6. Combustion

Principle of Combustion

Combustion refers to the rapid oxidation of fuel accompanied by the production of heat, or heat and light. Complete combustion of a fuel is possible only in the presence of an adequate supply of oxygen.

Oxygen (O₂) is one of the most common elements on earth making up 20.9% of our air. Rapid fuel oxidation results in large amounts of heat. Solid or liquid fuels must be changed to a gas before they will burn. Usually heat is required to change liquids

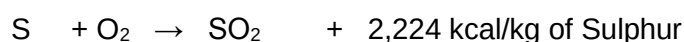
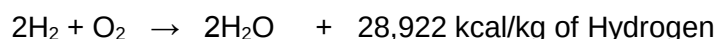
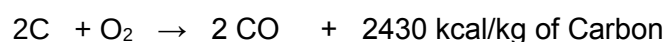
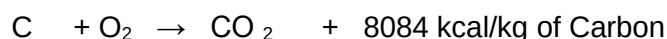
or solids into gases. Fuel gases will burn in their normal state if enough air is present.

Most of the 79% of air (that is not oxygen) is nitrogen, with traces of other elements. Nitrogen is considered to be a temperature educing dilute ant that must be present to obtain the oxygen required for combustion.

Nitrogen reduces combustion efficiency by absorbing heat from the combustion of fuels and diluting the flue gases. This reduces the heat available for transfer through the heat exchange surfaces. It also increases the volume of combustion by-products, which then have to travel through the heat exchanger and up the stack faster to allow the introduction of additional fuel air mixture.

This nitrogen also can combine with oxygen (particularly at high flame temperatures) to produce oxides of nitrogen (NO_x), which are toxic pollutants.

Carbon, hydrogen and sulphur in the fuel combine with oxygen in the air to form carbondioxide, water vapour and sulphur dioxide, releasing 8084, 28922 and 2224 kCals of heat respectively. Under certain conditions, Carbon may also combine with Oxygen to form Carbon Monoxide, which results in the release of a smaller quantity of heat (2430kCals/ kg of carbon) Carbon burned to CO_2 will produce more heat per pound of fuel than when CO or smoke are produced.



3 T's of Combustion

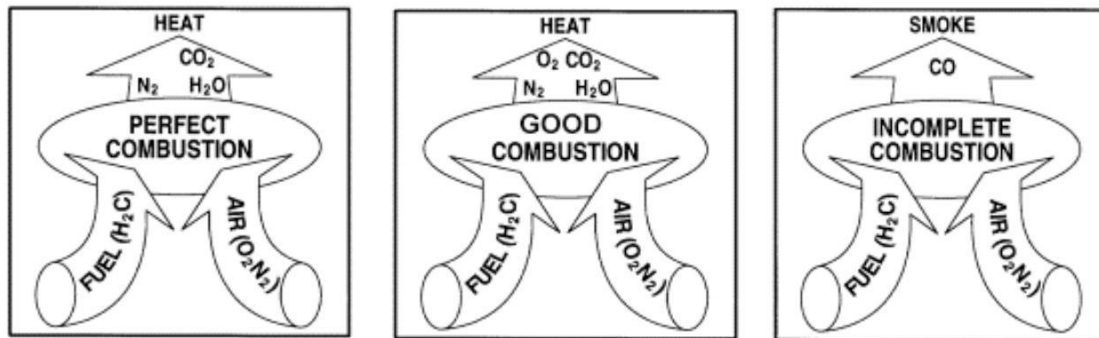
The objective of good combustion is to release all of the heat in the fuel. This is accomplished by controlling the "three T's" of combustion which are (1) Temperature high enough to ignite and maintain ignition of the fuel, (2) Turbulence or intimate mixing of the fuel and oxygen, and (3) Time sufficient for complete combustion.

Commonly used fuels like natural gas and propane generally consist of carbon and hydrogen. Water vapor is a by-product of burning hydrogen. To maintain its vaporous state, it robs heat from the flue gases, which would otherwise be available for more heat transfer.

Natural gas contains more hydrogen and less carbon per Kg than fuel oils and as such produces more water vapor. Consequently, more heat will be carried away by exhaust while firing natural gas. Too much, or too little fuel with the available combustion air may potentially result in unburned fuel and carbon monoxide generation. Avery specific amount of O_2 is needed for perfect combustion and some additional (excess) air is required for ensuring good combustion. However, too much excess air will reduce in heat and efficiency losses.

Not all of the heat in the fuel are converted to heat and absorbed by the steam

generation equipment. Usually all of the hydrogen in the fuel is burned and most boiler fuels, allow able with today's air pollution standards, contain little or no sulfur. So the main challenge in combustion efficiency is directed toward unburned carbon (in the ash or in completely burned gas), which forms CO instead of CO₂.



1.7. Combustion of Oil

Heating Oil to Correct Viscosity

When atomizing oil, it is necessary to heat it enough to get the desired viscosity. This temperature varies slightly for each grade of oil. The lighter oils do not usually require pre-heating. Typical viscosity at the burner tip (for LAP, MAP & HAP burners) for furnace oil should be 100 Redwood seconds-1 which would require heating the oil to about 105°C.

Stoichiometric Combustion

The efficiency of a boiler or furnace depends on efficiency of the combustion system. The amount of air required for complete combustion of the fuel depends on the elemental constituents of the fuel that is Carbon, Hydrogen, and Sulphur etc. This amount of air is called stanchion metric air. For ideal combustion process for burning one kg of a typical fuel oil containing 86% Carbon, 12% Hydrogen, 2% Sulphur, theoretically required quantity of air is 14.1kg. This is the minimum air that would be required if mixing of fuel and air by the burner and combustion is perfect. The combustion products are primarily Carbon Dioxide (CO₂), water vapor (H₂O) and Sulphur Dioxide (SO₂), which pass through the chimney along with the Nitrogen (N₂) in the air.

Rules for combustion of oil

- Atomise the oil completely to produce a fine spray
- Mix the air and fuel thoroughly
- Introduce enough air for combustion, but limit the excess air to a maximum of 15%
- Keep the burners in good condition

After surrendering useful heat in the heat absorption area of a furnace or boiler, the combustion products or fuel gases leave the system through the chimney, carrying a

way a significant quantity of heat with them.

Calculation of Stoichiometric Air

The specification of furnace oil from lab analysis is given below:

Constituents	% By weight
Carbon	85.9
Hydrogen	12
Oxygen	0.7
Nitrogen	0.5
Sulphur	0.5
H ₂ O	0.35
Ash	0.05

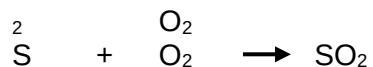
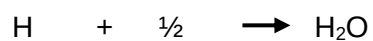
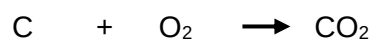
GCV of fuel: 10880kCal/kg

Calculation for Requirement of Theoretical Amount of Air

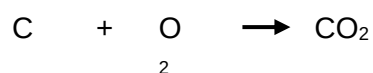
Considering a sample of 100kg of furnace oil. The chemical reactions are:

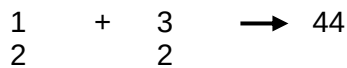
Element	Molecular Weight kg / kg mole

C	12
O ₂	32
H ₂	2
S	32
N ₂	28
CO ₂	44
SO ₂	64
H ₂ O	18

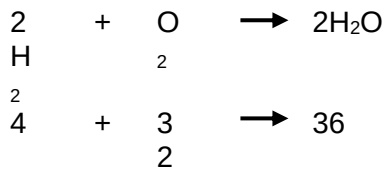
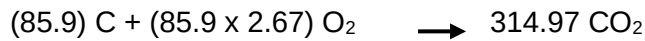


Constituents of fuel

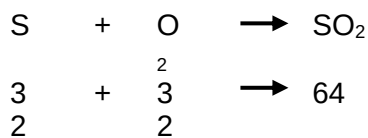
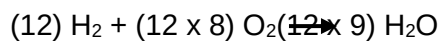




12 kg of carbon requires 32 kg of oxygen to form 44 kg of carbon dioxide therefore 1 kg of carbon requires 32/12 kg i.e 2.67 kg of oxygen



4 kg of hydrogen requires 32 kg of oxygen to form 36 kg of water, therefore 1 kg of hydrogen requires 32/4 kg i.e 8 kg of oxygen



32 kg of sulphur requires 32 kg of oxygen to form 64 kg of sulphur dioxide, therefore 1 kg of sulphur requires 32/32 kg i.e 1 kg of oxygen



$$\begin{array}{l} \text{Total Oxygen required} \\ (229.07+96+0.5) \end{array} = 325.57 \text{ kg}$$

$$\begin{array}{l} \text{Oxygen already present in} \\ 100 \text{ kg fuel (given)} \end{array} = 0.7 \text{ kg}$$

$$\begin{array}{l} \text{Additional Oxygen Required} \\ \end{array} = 325.57 - 0.7$$

$$= 324.87 \text{ kg}$$

$$\begin{array}{l} \text{Therefore quantity of dry air reqd.} \\ \text{(air contains 23\% oxygen by wt.)} \end{array} = (324.87) / 0.23$$

$$= 1412.45 \text{ kg of air}$$

$$\begin{array}{l} \text{Theoretical Air required} \\ \end{array} = (1412.45) / 100$$

$$= 14.12 \text{ kg of air / kg of fuel}$$

Calculation of theoretical CO₂ content in flue gases

$$\begin{array}{l} \text{Nitrogen in flue gas} \\ \end{array} = 1412.45 - 324.87 + 0.5$$

$$= 1088.08 \text{ kg}$$

Theoretical CO₂% in dry flue gas by volume is calculated as below :

$$\begin{aligned} \text{Moles of CO}_2 \text{ in flue gas} &= (314.97) / 44 = 7.16 \\ \text{Moles of N}_2 \text{ in flue gas} &= (1088.08) / 28 = 38.86 \\ \text{Moles of SO}_2 \text{ in flue gas} &= 1/64 = 0.016 \end{aligned}$$

$$\text{Theoretical CO}_2 \% \text{ by volume} = \frac{\text{Moles of CO}_2}{\text{Total moles (dry)}} \times 100$$

$$= \frac{7.16}{7.16 + 38.86 + 0.016} \times 100$$

$$= 15.6 \%$$

Calculation of constituents of flue gas with excess air

% CO₂ measured in flue gas = 10% (measured)

$$\% \text{ Excess air supplied (EA)} = \frac{7900 \times [(CO_2\%)_t - (CO_2\%)_a]}{(CO_2)_a \% \times [100 - (CO_2\%)_t]}$$

$$\% \text{ Excess air supplied (EA)} = \frac{7900 \times [15.6 - 10]}{10 \times [100 - 15.6]}$$

$$= 52.4\%$$

$$\begin{aligned} \text{Theoretical air required for 100 kg of fuel burnt} &= 1412.45 \text{ kg} \\ \text{Total quantity of air supply required with 52.4\% excess air} &= 1412.45 \times 1.524 \\ &= 2152.57 \text{ kg} \\ \text{Excess air quantity} &= 2152.57 - 1412.45 \\ &= 740.12 \text{ kg} \\ \text{O}_2 &= 740.12 \times 0.23 \\ &= 170.23 \text{ kg} \\ \text{N}_2 &= 740.12 - 170.23 \\ &= 570 \text{ kg} \end{aligned}$$

The final constitution of flue gas with 52.4% excess air for every 100 kg fuel.

$$\begin{aligned} \text{CO}_2 &= 314.97 \text{ kg} \\ \text{H}_2\text{O} &= 108.00 \text{ kg} \\ \text{SO}_2 &= 1 \text{ kg} \\ \text{O}_2 &= 170.23 \text{ kg} \end{aligned}$$

$$\begin{aligned} \text{N}_2 &= 1088.08 + 570 \\ &= 1658.08 \text{ kg} \end{aligned}$$

Determination of Actual CO₂% by calculation in dry flue gas by volume

$$\begin{aligned} \text{Moles of CO}_2 \text{ in flue gas} &= 314.97/44 = 7.16 \\ \text{Moles of SO}_2 \text{ in flue gas} &= 1/64 = 0.016 \\ \text{Moles of O}_2 \text{ in flue gas} &= 170.23 / 32 = 5.32 \\ \text{Moles of N}_2 \text{ in flue gas} &= 1658.08 / 28 = 59.22 \end{aligned}$$

$$\text{Actual CO}_2\% \text{ by volume} = \frac{\text{Moles of CO}_2}{\text{Total moles (dry)}} \times 100$$

$$= \frac{7.16}{7.16 + 0.016 + 5.32 + 59.22} \times 100$$

$$= \frac{7.16}{71.716} \times 100 = 10\%$$

$$\text{Actual O}_2\% \text{ by volume} = \frac{5.32 \times 100}{71.716} \times 100 = 7.42\%$$

Optimizing Excess Air and Combustion

For complete combustion of every one kg of fuel oil 14.1 kg of air is needed. In practice, mixing is never perfect, a certain amount of excess air is needed to complete combustion and ensure that release of the entire heat contained in fuel oil. If too much air than what is required for completing combustion were allowed to enter, additional heat would be lost in heating the surplus air to the chimney temperature. This would result in increased stack losses. Less air would lead to the incomplete combustion and smoke. Hence, there is an optimum excess air level for each type of fuel.

Control of Air and Analysis of Flue Gas

Thus in actual practice, the amount of combustion air required will be much higher than optimally needed. Therefore some of the air gets heated in the furnace boiler and leaves through the stack without participating in the combustion.

Chemical analysis of the gases is an objective method that helps in achieving finer air control. By measuring carbon dioxide (CO₂) or oxygen (O₂) in flue gases by continuous recording instruments or Orsat apparatus or some cheaper portable instruments, the excess air level as well as stack losses can be estimated with the graph as shown in Figure 1.2 and Figure 1.3. The excess air to be supplied depends on the type of fuel and the firing system. For optimum combustion of fuel oil, the CO₂ or O₂ in flue gases should be maintained at 14-15% in case of CO₂ and 2-3% in case of O₂ measurement.



Figure 1.2: Relation between CO₂ and excess air for fuel oil

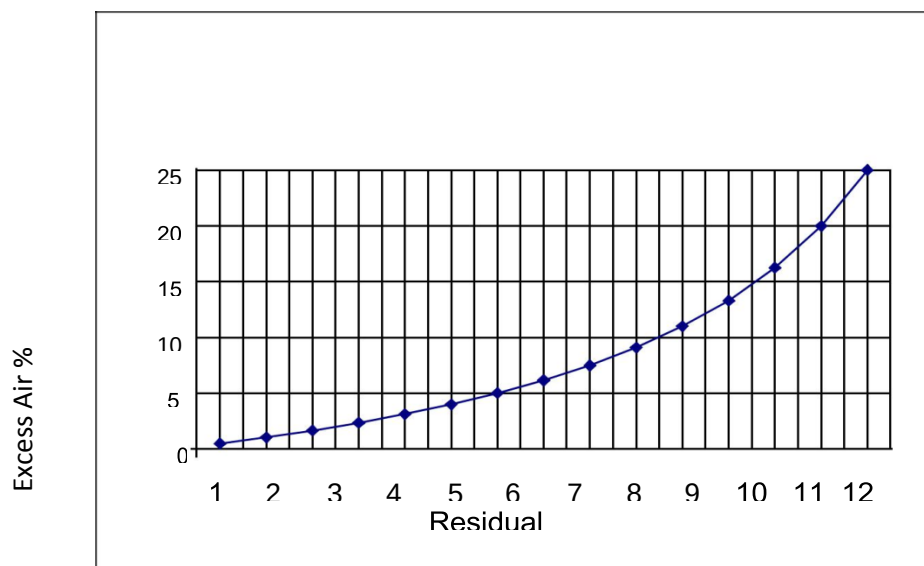


Figure 1.3: Relation between residual oxygen and excess air Oil Firing

Burners

The burner is the principal device for the firing of the fuel. The primary function of burner is to atomise fuel to millions of small droplets so that the surface area of the fuel is increased enabling intimate contact with oxygen in air. The finer the fuel drop lets are atomised, more readily will the particles come in contact with the oxygen in the air and burn.

Normally, atomization is carried out by primary air and completion of combustion is ensured by secondary air. Burners for fuel oil can be classified on a basis of the technique to prepare the fuel for burning i.e. atomization.

Figure1.4 shows as amplified burner head. The air is brought in to the head by means of a forced draft blower or fan. The gas is metered into the head through a series of valves. In order to get proper combustion, the air molecules must be thoroughly mixed with the gas molecules before they actually burn.

The mixing is achieved by burner parts designed to create high turbulence. If

insufficient turbulence is produced by the burner, the combustion will be incomplete and samples taken at the stack will reveal carbon monoxide as evidence.

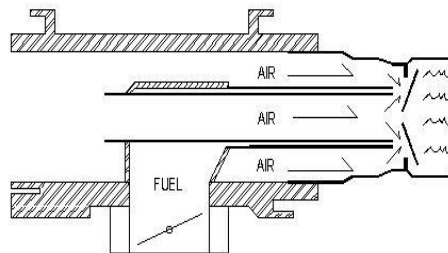


Figure 1.4:

Since the velocity of air affects the turbulence, it becomes harder and harder to get good fuel and air mixing at higher turn down ratios since the air amount is reduced. Towards the highest turndown ratios of any burner, it becomes necessary to increase the excess air amounts to obtain enough turbulence to get proper mixing. The better burner design will be one that is able to properly mix the air and fuel at the lowest possible air flow or excess air.

An important aspect to be considered in selection of burner is **turn down ratio**. Turn down ratio is the relationship between the maximum and minimum fuel input without affecting the excess air level. For example, a burner whose maximum input is 250,000kCals and minimum rate is 50,000kCals, has a 'Turn-Down Ratio' of 5 to1.

The air in the center is the primary air which is used for atomization and the one surrounding is the secondary air which ensures complete combustion.

1.8. Combustion of Coal

Features of coal combustion

1kg of coal will typically require 7-8kg of air depending upon the carbon, hydrogen, nitrogen, oxygen and sulphur content for complete combustion. This air is also known as theoretical or stoichiometric air.

If for any reason the air supplied is inadequate, the combustion will be incomplete. The result is poor generation of heat with some portions of carbon remaining unburnt (black smoke) and forming carbon monoxide instead of carbon dioxides.

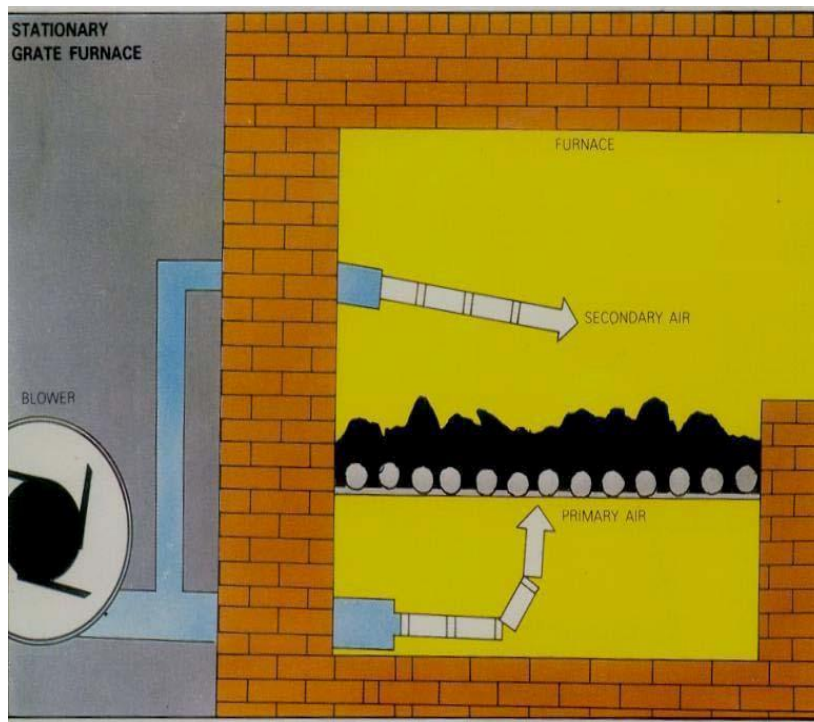


Figure 1.5: Stoker fired boilers

As in the case of oil, coal cannot be burnt with stoichiometric quantity of air. Complete combustion is not achieved unless an excess of air is supplied.

The excess air required for coal combustion depends on the type of coal firing equipment. Hand fired boilers use large lumps of coal and hence need very high excess air. Stoker fired boilers as shown in the figure 5 use sized coal and hence requires less excess air. Also in these systems primary air is supplied below the grate and secondary air is supplied over the grate to ensure complete combustion.

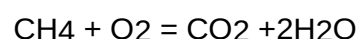
Fluidized bed combustion in which turbulence is created leads to intimate mixing of air and fuel resulting in further reduction of excess air. The pulverized fuel firing in which powdered coal is fired has the minimum excess air due to high surface area of coal ensuring complete combustion.

1.9. Combustion of Gas

Combustion Characteristics of Natural Gas

The stoichiometric ratio for natural gas (and most gaseous fuels) is normally indicated by volume. The air to natural gas (stoichiometric) ratio by volume for complete combustion vary between 9.5:1 to 10:1

Natural gas is essentially pure methane, CH₄. Its combustion can be represented as follows:



So for every 16Kgs of methane that are consumed, 12Kgs of carbon are released (as carbon dioxide) and 44Kgs of carbon dioxide are produced. (Remember that the atomic weights of carbon, oxygen and hydrogen are 12, 16 and 1, respectively.)

Natural gas is primarily composed of methane, CH_4 . When mixed with the proper amount of air and heated to the combustion temperature, it burns. **Figure 1.6** shows the process with the amount of air and fuel required for perfect combustion.

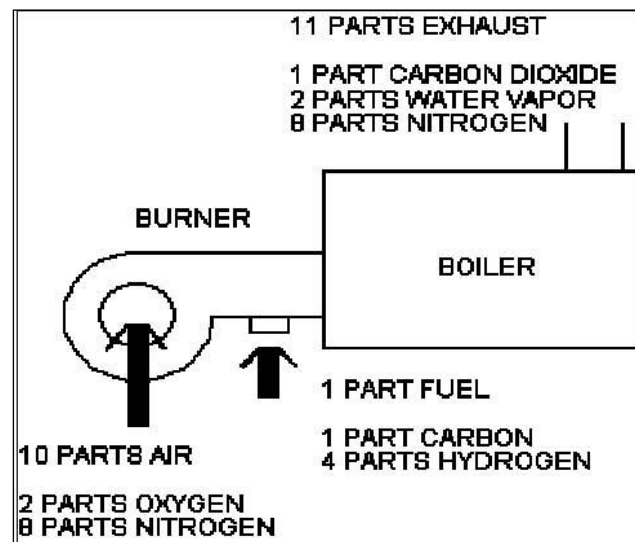


Figure 1.6: Combustion of natural gas

Low-And High-Pressure Gas Burners.

The important thing in all gas-burning devices is a correct air-and-gas mixture at the burner tip. Low-pressure burners (figure 1.7), using gas at a pressure less than 0.15 kg/cm^2 (2 psi), are usually of the multi jet type, in which gas from a manifold is supplied to a number of small single jets, or circular rows of small jets, centered in or discharging around the inner circumference of circular air openings in a block of some heat-resisting material. The whole is encased in a rectangular cast-iron box, built in to the boiler setting and having louver doors front to regulate the air supply. Draft may be natural, induced, or forced.



Figure 1.7: Low pressure burner

In a high-pressure gas mixer (figure 1.8), the energy of the gas jet draws air in to the mixing chamber and delivers a correctly proportioned mixture to the burner. When

the regulating valve is opened, gas flows through a small nozzle into aventurine tube (a tube with a contracted section). Entrainment of air with high-velocity gas in the narrow venture section draws air in through large openings in the end. The gas-air mixture is piped to a burner. The gas-burner tip may be in a variety of forms. In a sealed-in tip type, the proper gas-air mixture is piped to the burner, and no additional air is drawn in around the burner tip. Size of the air openings in the ventured been dis-increased or decreased by turning a revolving Sutter, which can be locked in any desired position. Excess air level in natural gas burner is in the order of 5%.

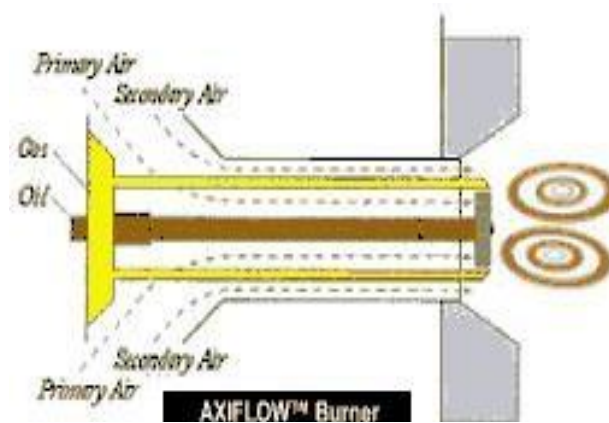


Figure 1.8: High pressure gasmixer

Draft

The function of draft is to exhaust the products of combustion into the atmosphere. The draft can be created by natural or artificial means.

Natural Draft

It is the draft produced by a chimney alone. It is caused by the difference in weight between the column of hot gas inside the chimney and column of outside air of the same height and cross section. Being much lighter than outside air, chimney flue gas tends to rise, and the heavier outside airflows in through the ash pit to take its place. It is usually controlled by hand-operated dampers in the chimney and breeching connecting the boiler to the chimney. Here no fans or blowers are used. The products of combustion are discharged at such a height that it will not be a nuisance to the surrounding community.

Mechanical Draft

It is the draft artificially produced by fans. Three basic types of drafts that are applied are:

Balanced Draft: Forced-draft (F-D) fan (blower) pushes air into the furnace and an induced-draft (I-D) fan draws gases into the chimney there by providing draft to

remove the gases from the boiler. Here the furnace is maintained at from 0.05 to 0.10 in. of water gauge below atmospheric pressure.

Induced Draft: An induced-draft fan provides enough draft for flow in to the furnace, causing the products of combustion to discharge to atmosphere. Here the furnace is kept at as light negative pressure below the atmospheric pressure so that combustion air flows through the system.

Forced Draft: The Forced draft system uses a fan to deliver the air to the furnace, forcing combustion products to flow through the unit and up the stack.

Combustion Controls

Combustion controls assist the burner in regulation of fuel supply, air supply, (fuel to air ratio), and removal of gases of combustion to achieve optimum boiler efficiency. The amount of fuel supplied to the burner must be in proportion to the steam pressure and the quantity of steam required. The combustion controls are also necessary as safety device to ensure that the boiler operates safely.

Various types of combustion controls in use are:

On/Off Control

The simplest control, ON/OFF control means that either the burner is firing at full rate or it is OFF. This type of control is limited to small boilers.

High/Low/Off Control

Slightly more complex is HIGH / LOW / OFF system where the burner has two firing rates. The burner operates at slower firing rate and then switches to full firing as needed. Burner can so revert to low firing position at reduced load. This control is fitted to medium sized boilers.

Modulating Control

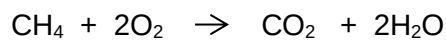
The modulating control operates on the principle of matching the steam pressure demand by altering the firing rate over the entire operating range of the boiler. Modulating motors use conventional mechanical linkage or electric valves to regulate the primary air, secondary air, and fuel supplied to the burner. Full modulation means that boiler keeps firing, and fuel and air are carefully matched over the whole firing range to maximize thermal efficiency.

Examples:

Problem -1:

For combustion of 500 kg/hr of natural gas containing 100% methane, calculate the percentage of CO₂ in the flue gas while 15% excess air is supplied.

Solution:



1 mole of Methane requires 2 moles of Oxygen.

16 Kg of Methane requires 64 Kg of Oxygen.

16 Kg of Methane produces 44 Kg of CO₂.

500 Kg/hr of Methane requires 2000 Kg/hr of Oxygen.

500 Kg/hr of Methane produce 1375 Kg/hr of CO₂.

$$\begin{aligned}\text{Theoretical air required for combustion} &= 2000 / 0.23 \\ &= 8696 \text{ Kg/hr}\end{aligned}$$

Considering 15% excess air,

$$\begin{aligned}\text{Actual air supplied for combustion is} &= 8696 * 1.15 \\ &= 10,000.4 \text{ Kg/hr of air}\end{aligned}$$

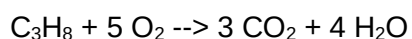
$$\begin{aligned}\text{Flue gas generation with 15\% excess air} &= 500 + 10,000.4 \\ &= 10,500.4 \text{ Kg/hr}\end{aligned}$$

$$\begin{aligned}\text{Percentage CO}_2 \text{ in the flue gas} &= (1375 / 10,500.4) \times 100 \\ &= 13.1\%.\end{aligned}$$

Problem -2:

Propane is used as fuel in heaters for preheating paints. Calculate the Air to Fuel ratio for complete combustion of C₃H₈ (Propane) and CO₂ released per kg of propane, if 15% excess air is supplied to the heater.

Solution:



1 mole of propane requires 5 moles of Oxygen.

Molecular weight of Propane is 44 kg per mole.

44 kg of Propane requires 160 kg of Oxygen.

$$\text{Theoretical air required for combustion} = 160 / 0.23 = 695.6 \text{ Kg/hr}$$

Excess air supplied is 15 %,

Actual air supplied for combustion is $= 695.6 \times 1.15$
 $= 800 \text{ kg/hr of air}$

Air to Fuel ratio $= 800 / 44$
 $= 18.18$

From the above chemical equation,

44 kg of Propane releases 132 kg of CO_2

3 kg of CO_2 is released from 1 kg of propane.

2. BOILER

2.1. Introduction

A **boiler** is an enclosed vessel that provide same anchor combustion heat to be transferred into water until it becomes heated water or a steam. The steam or hot water under pressure is then usable for transfer ring the heat to a process. Water is a useful and cheap medium for transferring heat to a process. When water is boiled in to steam its volume increases about 1,600 times, producing a force that is almost as explosive as gun powder. This causes the boiler to be extremely dangerous equipment that must be treated with utmost respect.

Typical Boiler Specification

Boiler make and year	Nestler1982
MCR rating	6 TPH (F &A 100 0C)
Type of boiler	3 Pass Fire tube Package Boiler
Design steam pressure	10.5 kg/cm ² (150 PSIG)Package Boiler
Operating pressure	110-130PSIG
Fuel used	Furnace oil

The process of heating a liquid until it reaches its gaseous state is called evaporation. Heat is transferred from one body to another by means of (1) radiation, which is the transfer of heat from a hot body to a cold body through a conveying medium without physical contact, (2) convection, the transfer of heat by a conveying medium, such as air or water and (3) conduction, transfer of heat by actual physical contact, molecule to molecule. The heating surface is any part of the boiler metal that has hot gases of combustion on one side and water on the other. Any part of the boiler metal that actually contributes to making steam is heating surface. The amount of heating surface of a boiler is expressed in square meters. The larger the heating surface a boiler has, the more efficient it becomes. The measurement of the steam produced is generally in tons of water evaporated to steam per hour.

2.2. Boiler Systems

The feed water system provides water to the boiler and regulates it automatically to meet the steam demand. Various valves provide access for maintenance and repair. The steam system collects and controls the steam produced in the boiler. Steam is directed through piping to the point of use. Throughout the system, steam pressure is regulated using valves and checked with steam pressure gauges. The fuel system includes all equipment used to provide fuel to generate the necessary heat. The equipment required in the fuel system depends on the type of fuel used in the system. A typical boiler room schematic is shown in Figure2 .1.

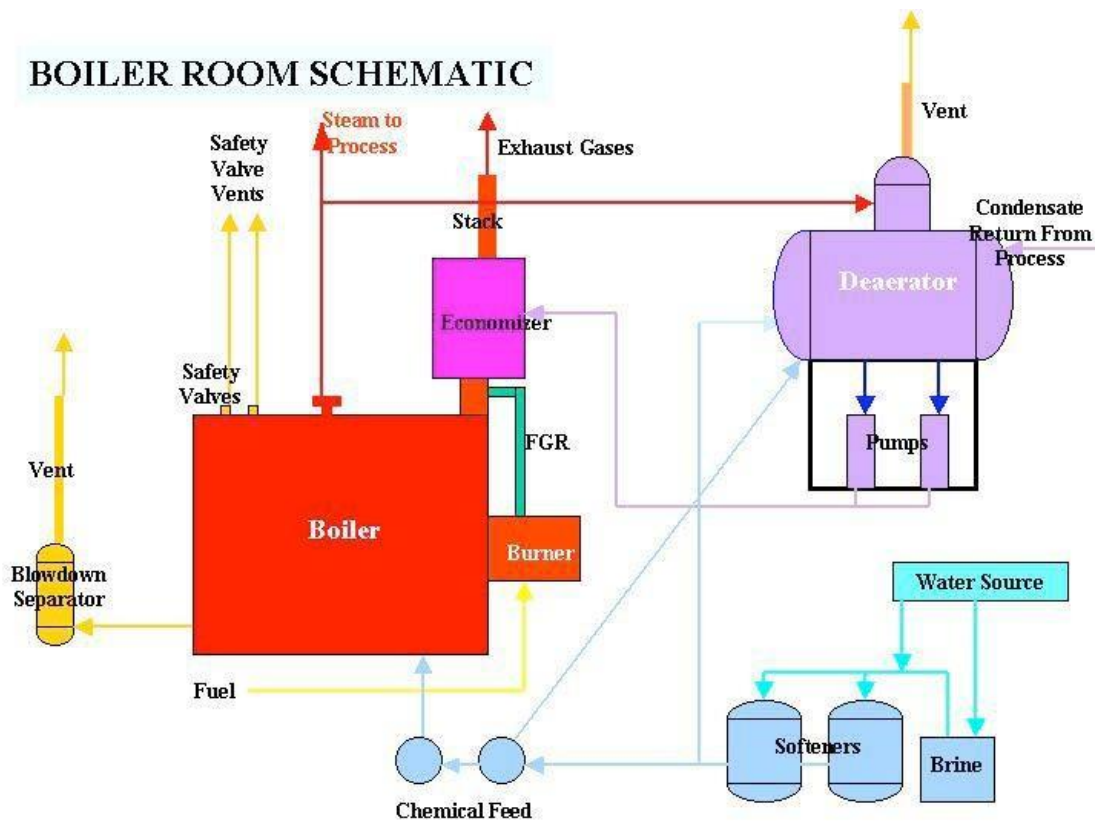


Figure 2 .1: Boiler room

The water supplied to the boiler that is converted into steam is called **feed water**. The two sources of feed water are: (1) **Condensate** or condensed steam returned from the processes and (2) **Make up water** (usually raw water) which must come from outside the boiler room and plant processes. For higher boiler efficiencies, the feed water is heated by economizer.

2.3. Boiler Types and Classifications

There are virtually infinite numbers of boiler designs but generally they fit into one of the two categories:

Fire tube or "fire in tube" boilers, contain long steel tubes through which the hot gasses from a furnace pass and around which the water to be changed to steam circulates. (Refer Figure 2.2). Fire tube boilers, typically have a lower initial cost, are more fuel efficient and easier to operate but they are limited generally to capacities of 25 tons/hr and pressures of 17.5 kg/cm².

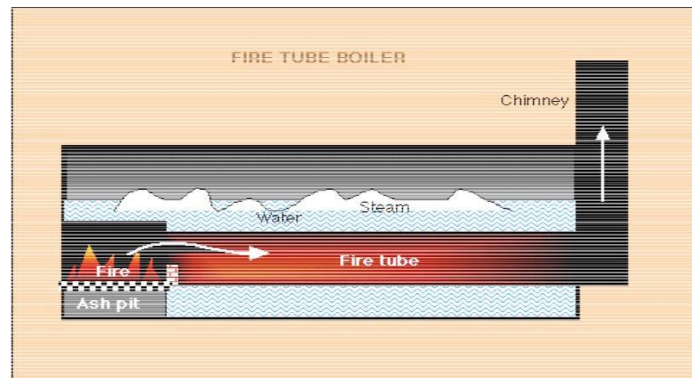


Figure 2.2: Fire tube boiler

Water tube or "water in tube" boilers in which the conditions are reversed with the water passing through the tubes and the hot gasses passing out side the tubes. (Refer figure 2.3).

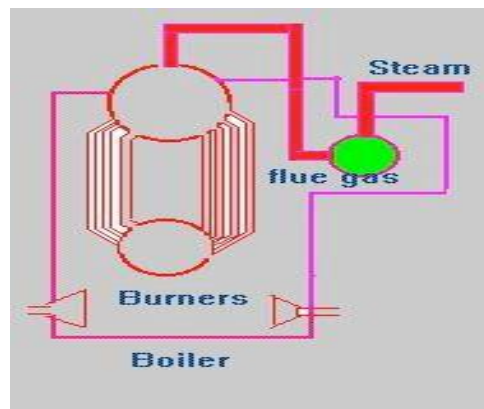


Figure 2.3: Water tube boiler

Packaged Boiler: The packaged boiler is so called because it comes as a complete package. Once delivered to site it requires only the steam, water pipe work, fuel supply and electrical connections to be made for it to become operational. Package boilers are generally of shell type with fire tube designs o as to achieve high heat transfer rates by both radiation and convection (Refer Figure2.4).



Figure 2.4: Packaged boiler

The features of package boilers are:

- Small combustion space and high heat release rate resulting in faster evaporation.
- Large number of small diameter tubes leading to good convective heat transfer.
- Forced or induced draft systems resulting in good combustion efficiency.
- Number of passes resulting in better overall heat transfer.
- Higher thermal efficiency levels compared with other boilers.

These boilers are classified based on the number of passes-the number of times the hot combustion gases pass through the boiler. The combustion chamber is taken as the first pass after which there maybe one, two or three sets of fire-tubes. The most common boiler is a three-pass unit with two sets of fire-tubes and the exhaust gases exiting through the rear of the boiler.

Stoker Fired Boiler:

Stokers are classified according to the method of feeding fuel to the furnace and by the type of grate. The main classifications are:

- Chain-grate or traveling-grate stoker
- Spreader stoker

Chain-Grate or Traveling-Grate Stoker Boiler

Coal is fed on to one end of a moving steel grate. As grate moves along the length of the furnace, the coal burns before dropping off at the end as ash. Some degree of skill is required, particularly when setting up the grate, air dampers and baffles, to ensure clean combustion leaving the minimum of un burnt carbon in the ash.

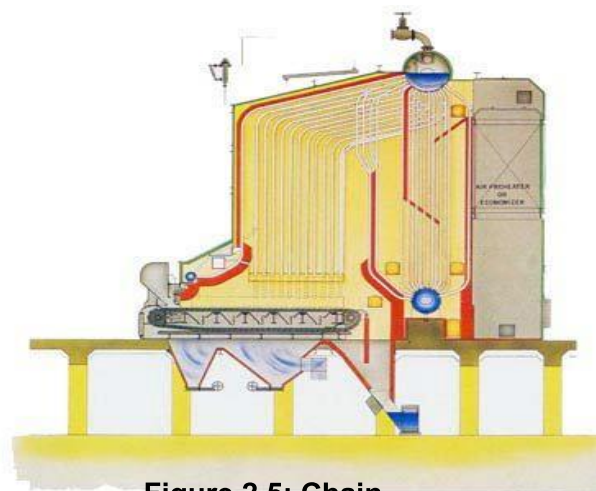


Figure 2.5: Chain-

The coal-feed hopper runs along the entire coal-feed end of the furnace. A coal grate is used to control the rate at which coal is fed in to the furnace by controlling the thickness of the fuel bed. Coal must be uniform in size as large lumps will not burn out completely by the time they reach the end of the grate (Refer Figure2.5).

Spreader Stoker Boiler

Spreader stokers utilize a combination of suspension burning and grate burning. The coal is continually fed into the furnace above a burning bed of coal. The coal fines are burned in suspension; the larger particles fall to the grate, where they are burned in a thin, fast- burning coal bed. This method of firing provides good flexibility to meet load fluctuations, since ignition is almost instantaneous when firing rate is increased. Hence, the spreader stoker is favored over other types of stokers in many industrial applications.

Pulverized Fuel Boiler

The coal is ground (pulverized) to a fine powder, so that less than 2% is + 300 micro metre (μm) and 70-75% is below 75 microns, for a bituminous coal. The pulverized coal is blown with part of the combustion air into the boiler plant through a series of burner nozzles. Secondary and tertiary air may also be added.

Combustion takes place at temperatures from 1300-1700°C, depending largely on coal rank. Particle residence time in the boiler is typically 2-5 seconds, and the particles must be small enough for complete burn out to have taken place during this time.

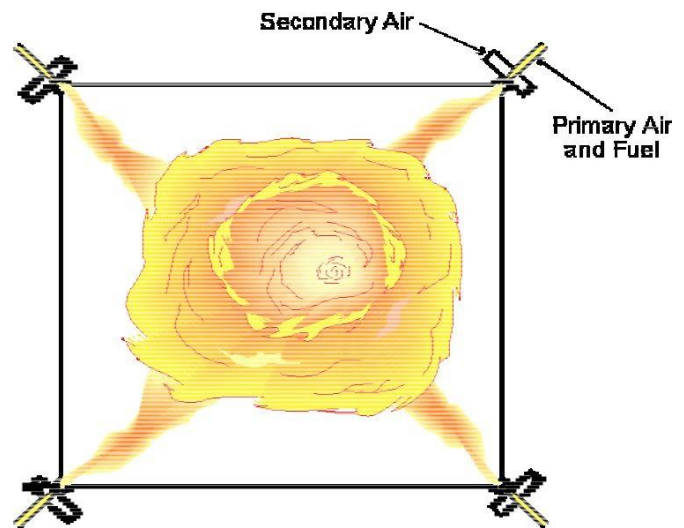


Figure 2.6: Tangential firing

This technology is well developed, and there are thousands of units around the world, accounting for well over 90% of coal-fired capacity. Pulverized coal fired boiler can be used to fire a wide variety of coals.

One of the most popular systems for firing pulverized coal is the tangential firing, using four burners corner to corner to create a fire ball at the center of the furnace. See Figure 2.6 below.

FBC Boiler

Fluidized bed combustion has significant advantages over conventional firing systems and offers multiple benefits namely fuel flexibility, reduced emission of noxious pollutants such as SO_x and NO_x, compact boiler design and higher combustion efficiency.

When an evenly distributed air or gas is passed upward through a finely divided bed of solid particles such as sand supported on a fine mesh, the particles are undisturbed at low velocity. As air velocity is gradually increased, a stage is reached when the individual particles are suspended in the air stream. Further, increase in velocity gives rise to bubble formation, vigorous turbulence and rapid mixing and the bed is said to be fluidized.

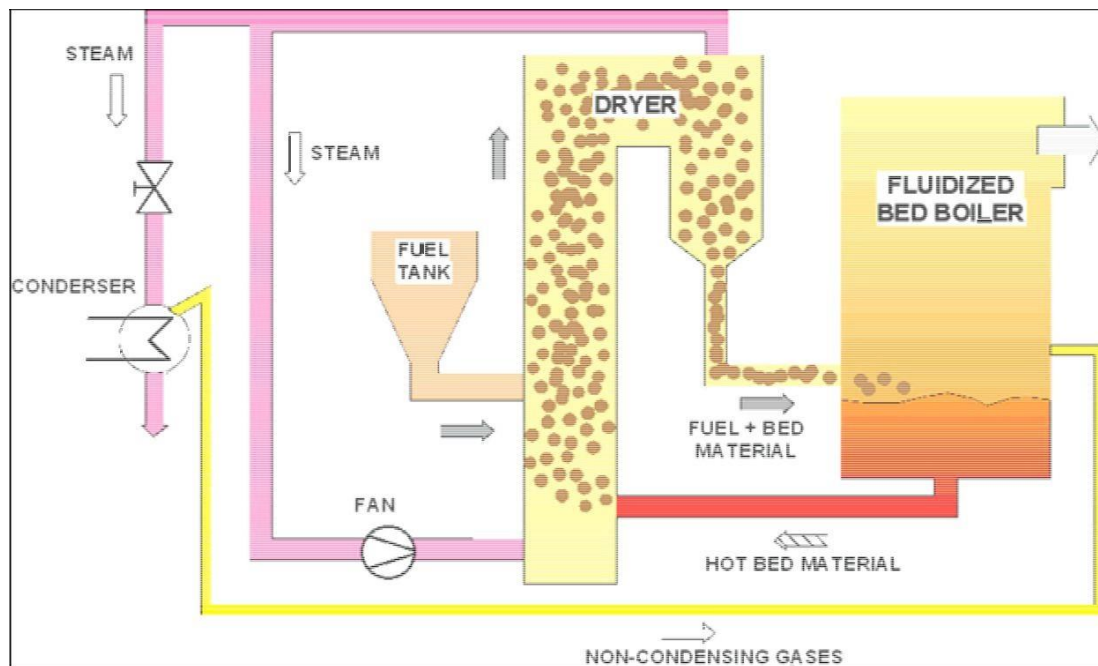


Figure 2.7: Schematic of fluidized bed boiler

If the sand in a fluidized state is heated to the ignition temperature of the coal and the coal is injected continuously into the bed, the coal will burn rapidly and the bed attains a uniform temperature due to effective mixing. Proper air distribution is vital for maintaining uniform fluidization across the bed. Both dry and wet ash disposal systems can be adopted for transporting bottom ash and fly ash. (Refer Figure 2.7).

Super Critical Boiler

In the temperature entropy diagram of steam, a point is reached where the boiling water and dry saturated steam lines converge and at that point, the latent heat is zero. The critical point corresponds to a pressure of 221.2 bar absolute and a temperature of 374.18 °C.

If water is heated beyond the above condition, steam parameters are referred to as super critical. A boiler producing steam above the critical pressure is called the supercritical boiler. While sub-critical boiler has three distinct sections - economiser, evaporator and super heater the supercritical boiler has only an economiser and super heater. The advantages of super critical boilers are

- Higher heat transfer rate
- More flexible in accepting load variation
- Greater ease of operation
- High thermal efficiency (40-42% of power generating stations)
- The absence of two-phase mixer minimises the problems of erosion and corrosion
- Steadier pressure level

The super critical boilers call for special materials to be used for constituent heat transfer surfaces like drum, water walls, economizer and re-heaters, in order to withstand the elevated pressure & temperature conditions.

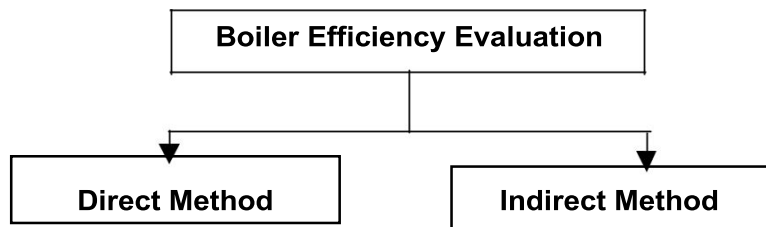
2.4. Performance Evaluation of Boilers

The performance of boiler, like efficiency and evaporation ratio reduces with time due to poor combustion, heat transfer surface fouling and poor operation and maintenance. Deteriorating fuel quality, water quality etc. also leads to poor boiler performance. Efficiency tests help us to find out the deviation of boiler efficiency from the best efficiency and target problems for corrective action.

Boiler Efficiency

Thermal efficiency of boiler is defined as the percentage of heat input that is effectively utilized to generate steam. There are two methods of assessing boiler efficiency.

- 1) **The Direct Method:** Where the energy gain of the working fluid (water and steam) is compared with the energy content of the boiler fuel.
- 2) **The Indirect Method:** Where the efficiency is the difference between the losses and the energy input.



a. Direct Method

This is also known as 'input-output method' due to the fact that it needs only the useful output (steam) and the heat input (i.e. fuel) for evaluating the efficiency. This efficiency can be evaluated using the formula.

$$\text{Boiler Efficiency} = \frac{\text{Heat Output}}{\text{Heat Input}} \times 100$$

Parameters to be monitored for the calculation of boiler efficiency by direct method are :

- Quantity of steam generated per hour (Q) in kg/hr.
- Quantity of fuel used per hour (q) in kg/hr.
- The working pressure (in kg/cm²(g)) and superheat temperature (°C), if any
- The temperature of feed water (°C)
- Type of fuel and gross calorific value of the fuel (GCV) in kcal/kg of fuel

$$\text{Boiler Efficiency } (\eta) = \frac{Q \times (h_g - h_f)}{q \times \text{GCV}} \times 100$$

Where, h_g - Enthalpy of saturated steam in kcal/kg of steam
 h_f - Enthalpy of feed water in kcal/kg of water

The fuel calorific value may be gross or net and accordingly, the efficiency reported is referred to as efficiency on GCV or NCV basis.

Example

Find out the efficiency of the boiler by direct method with the data given below:

Type of boiler	: Coal fired
Quantity of steam (dry) generated	: 8 TPH
Steam pressure / temp	: 10 kg/cm ² (g)/ 180 °C
Quantity of coal consumed	: 1.8 TPH
Feed water temperature	: 85 °C
GCV of coal	: 3200 kCal/kg
Enthalpy of saturated steam at 10 kg/cm ² pressure	: 665 kCal/kg(saturated)
Enthalpy of feed water	: 85 kCal/kg

Solution :

$$\begin{aligned}\text{Boiler Efficiency } (\eta) &= \frac{8 \times (665 - 85)}{1.8 \times 3200} \times 100 \\ &= 80\% \text{ (on GCV basis)}\end{aligned}$$

It should be noted that boiler may not generate 100% saturated dry steam and there may be some amount of wetness in the steam. Since it is practically difficult to measure the dryness fraction, it is assumed the boiler generates 100% saturated steam for calculation purposes. The resulting errors are likely to be in significant.

Advantages:

- Plant people can evaluate quickly the efficiency of boilers
- Requires few parameters for computation
- Needs few instruments for monitoring

Disadvantages:

- Does not give clues to the operator as to why efficiency of system is lower
- Does not calculate various losses accountable for various efficiency levels

b. Indirect Method

There are reference standards for Boiler Testing at Site using indirect method namely British Standard, BS845:1987 and USA Standard is 'ASMEPTC-4-1 Power Test Code Steam Generating Units'.

Indirect method also called as heat loss method. The efficiency can be arrived at, by subtracting the heat loss fractions from 100. All standard does not includes blow down

loss in the efficiency determination process

However, the efficiency calculations are meant for practicing energy managers, simpler calculation procedure is being adopted in industries.

The principle losses that occur in a boiler are:

- Loss of heat due to dry flue gas
- Loss of heat due to moisture in fuel and combustion air
- Loss of heat due to combustion of hydrogen
- Loss of heat due to radiation
- Loss of heat due to un burnt

In the above, loss due to moisture in fuel and the loss due to combustion of hydrogen cannot be controlled by design and is dependent on the fuel and these two losses are practically zero while computing the efficiency on the basis of net calorific value.

The data required for calculation of boiler efficiency using indirect method are:

Ultimate analysis of fuel (H₂, O₂, S, C, moisture content, ash content)

Percentage of Oxygen or CO₂ in the flue gas

Flue gas temperature in °C (T_f)

Ambient temperature in °C (T_a)

Humidity of air in kg/kg of dry air

GCV of fuel kcal/kg

Percentage combustible in ash (in case of solid fuels)

GCV of ash in kcal/kg (in case of solid fuels)

Solution:

$$\text{Excess Air supplied (EA)} = \frac{O_2 \%}{21 - O_2 \%} \times 100$$

Theoretical air requirement

$$= [(11.6 \times C) + \{[34.5 \times (H_2 - O_2/8)] + (4.35 \times S)\}] / 100 \text{ kg/kg of fuel}$$

$$\text{Actual mass of air supplied/ kg of fuel (AAS)} = \{1 + \text{EA}/100\} \times \text{theoretical air}$$

$$\text{i. Percentage heat loss due to dry flue gas} = \frac{m \times C_p \times (T_f - T_a)}{\text{GCV of fuel}} \times 100$$

where,

m = mass of dry flue gas in kg/kg of fuel

= (mass of dry products of combustion per kg of fuel) + (mass of N₂ in Fuel on 1kg basis) + (mass of N₂ in actual mass of air supplied).

C_p = specific heat of flue gas (0.24 kcal/kg deg. C)

- ii. Percentage heat loss due to evaporation of water formed due to H_2 in fuel

$$= \frac{9 \times H_2 \times \{584 + 0.45 (T_f - T_a)\}}{\text{GCV of fuel}} \times 100$$

where,

H_2 = percentage of H_2 in 1 kg of fuel

0.45 is the specific heat of super-heated steam

584 Latent heat of superheated vapour at partial pressure

- iii. Percentage heat loss due to evaporation of moisture present in fuel

$$= \frac{M \times \{584 + 0.45 (T_f - T_a)\}}{\text{GCV of fuel}} \times 100$$

where,

M = percentage moisture in 1 kg of fuel

- iv. Percentage heat loss due to moisture present in air

$$= \frac{A \times S \times \text{humidity} \times 0.45 \times (T_f - T_a)}{\text{GCV of fuel}} \times 100$$

- v. Percentage heat loss due to partial conversion of C to CO

$$= \frac{\%CO \times C}{\%CO + \%CO_2} \times \frac{5654}{\text{GCV of fuel}} \times 100$$

where,

CO = Volume of CO in flue gas (%)
(1% = 10000 ppm)

CO₂ = Actual Volume of CO₂ in flue gas (%)

C = Carbon content kg / kg of fuel

- vi. Percentage heat loss due to un burnt in fly ash

$$= \frac{\text{Total ash collected per kg of fuel burnt} \times \text{G.C.V of fly ash} \times 100}{\text{GCV of fuel}}$$

- vii. Percentage heat loss due to un burnt in botto mash

$$= \frac{\text{Total ash collected per kg of fuel burnt} \times \text{G.C.V of bottom ash} \times 100}{\text{GCV of fuel}}$$

- viii. Percentage heat loss due to radiation and other un accounted loss

The actual radiation and convection losses are difficult to assess because of particular emissivity of various surfaces, its inclination, airflow pattern etc. In a relatively small boiler, with a capacity of 10MW, the radiation and unaccounted losses could amount to between 1% and 2% of the gross calorific value of the fuel, while in a 500MW boiler, values between 0.2% to 1% are typical. The loss may be assumed appropriately depending on the surface condition.

$$\text{Efficiency of boiler } (\eta) = 100 - (i + ii + iii + iv + v + vi + vii)$$

Example: Calculating boiler efficiency by indirect method

- Type of boiler : Oil fired
- Ultimate analysis of Oil:
C - 84.0%; H₂ -12.0%; S- 3.0%; O₂ -1.0% ; GCV of Oil : 10200kCal/kg
- Percentage of Oxygen in flue gas: 7
- Percentage of CO₂ in flue gas : 11
- Flue gas temperature (T_f) : 220°C
- Ambient temperature (T_a) : 27 °C
- Humidity of air : 0.018 kg/kg of dry air
- Radiation and other unaccounted losses: 3.5% (estimated)

Solution:

1. Excess air supplied (EA) = $(7 \times 100) / (21 - 7) = 50\%$
2. Theoretical air requirement
$$= [(11.6 \times C) + \{34.5 \times (H_2 - O_2/8)\} + (4.35 \times S)] / 100 \text{ kg/kg of fuel}$$
$$= [(11.6 \times 84) + \{34.5 \times (12 - 1/8)\} + (4.35 \times 3)] / 100 \text{ kg/kg of fuel}$$
$$= 974.4 + 409.6875 + 13.05$$
$$= 13.97$$
3. Actual mass of air supplied per kg of fuel
$$= [1 + EA/100] \times \text{Theo. Air (AAS)}$$
$$= [1 + 50/100] \times 13.97$$
$$= 20.96$$
4. Percentage heat loss due to dry flue gas (L1) = $\frac{m \times C_p \times (T_f - T_a)}{\text{GCV of fuel}} \times 100$

$$m = (0.84 \times (44/12)) + (0.03 \times (64/32)) + (20.96 \times 0.77) + ((20.96 - 13.97) \times 0.23) \\ = 3.08 + 0.06 + 16.14 + 1.61 = 20.89$$

$$L1 = 20.89 \times 0.24 \times (220 - 27) \times 100 / 10200 = 9.49\%$$

5. Percentage heat loss due to evaporation of water formed due to H_2 in fuel (L2)

$$= \frac{9 \times H_2 \times \{584 + 0.45 (T_f - T_a)\}}{\text{GCV of fuel}} \times 100$$

$$L2 = 9 \times 12 \{584 + 0.45 (220-27)\} \times 100 / 10200 = 7.10\%$$

6. Percentage heat loss due to moisture present in air (L3)

$$= \frac{AAS \times \text{humidity} \times 0.45 \times (T_f - T_a)}{\text{GCV of fuel}} \times 100$$

$$L3 = 20.96 \times 0.018 \times 0.45 (220-27) \times 100 / 10200 = 0.31\%$$

7. Percentage heat loss due to radiation and other unaccounted losses (L4) = 3.5%
(given)

$$\begin{aligned} \text{Boiler Efficiency} &= 100 - (L1 + L2 + L3 + L4) \\ &= 100 - (9.49 + 7.1 + 0.31 + 3.5) = 79.6\% \end{aligned}$$

Boiler Evaporation Ratio

Evaporation ratio means kilogram of steam generated per kilogram of fuel consumed.

Typical values of Evaporation ratio for different type of fuels are as follows:

Biomass fired boilers	: 2.0 to 3.0
Coal fired boilers	: 4.0 to 5.5
Oil fired boilers	: 13.5 to 14.5
Gas fired boilers	: 11.0 to 13.0

However, the above ratio will depend upon the type of boiler and associated efficiencies.

2.5. Boiler Blow down

The impurities found in boiler water depend on the untreated feed water quality, the treatment process used and the boiler operating procedures. As a general rule, the higher is the boiler operating pressure, the greater will be the sensitivity to impurities. As the feed water materials evaporate in to steam, dissolved solids concentrate in the boiler either in a dissolved or suspended state. Above a certain level of concentration, these solids encourage foaming and cause carryover of water in to the steam. This leads to scale formation inside the boiler, resulting in localized overheating and ending finally in tube failure.

It is therefore necessary to control the level of concentration of the solid sand this is achieved by the process of 'blowing down', where a certain volume of water is blown off and is automatically replaced by feed water - thus maintaining the optimum level of total dissolved solids (TDS) in the water. Blow down is necessary to protect the surfaces of the heat exchanger in the boiler. However, blow down can be a significant source of heat loss, if improperly carried out. The maximum amount of total dissolved solids (TDS) concentration permissible in various types of boilers is given in Table 2.1.

Table 2.1: Recommended TDS levels for various boilers

	Boiler Type	Maximum TDS (ppm)
1.	Lancashire	10,000 ppm
2.	Smoke and water tube boilers (12 kg/cm ²)	5,000 ppm
3.	Low pressure Water tube boiler	2000-3000
3.	High Pressure Water tube boiler with super heater etc.	3,000 - 3,500 ppm
4.	Package and economic boilers	3,000 ppm
5.	Coil boilers and steam generators	2000 (in the feed water)

The following formula gives the quantity of blow down required:

$$\text{Blow down (\%)} = \frac{[\text{Feed water TDS} \times \% \text{ Make up water}]}{(\text{Maximum Permissible TDS in Boiler water} - \text{Feed water TDS})}$$

If maximum permissible limit of TDS as in a package boiler is 3000ppm, percentage make up water is 10% and TDS in feed water is 300ppm, then the percentage blow down is given as:

$$\begin{aligned} &= (300 \times 10) / (3000 - 300) \\ &= 1.11\% \end{aligned}$$

If boiler evaporation rate is 3000 kg/hr, then required blow down rate is:

$$\begin{aligned} &= 3000 \times 0.0111 \\ &= 33.3\text{kg/hr} \end{aligned}$$

Conductivity as Indicator of Boiler Water Quality

Conductivity is a standard measurement for monitoring the overall total dissolved solids present in the boiler. Arise in conductivity indicates arise in the "contamination" of the boiler water.

Intermittent vs. Continuous Blow down

Conventional methods for blowing down the boiler depend on two kinds of blow down – intermittent and continuous.

Intermittent Blow down

The parameters that are most often monitored to ensure the quality of steam are TDS or conductivity, pH, Silica and Phosphates concentration. The boiler is blown down by manually operating a valve fitted to discharge pipe at the lowest point of boilers shell to reduce these levels and keeping them controlled to a point where the steam quality is not likely to be affected. A substantial amount of heat energy is lost in this process. In intermittent blow down, a large diameter line is opened for a short period of time, the time being based on a thumb rule such as “once a shift for 2 minutes”.

Continuous Blow down

There is a steady and constant dispatch of small stream of concentrated boiler water. In a continuous blow down, large quantities of heat are wasted though it is inevitable especially in large high pressure boilers. However, opportunity exists for recovering this heat by blowing in to a flash tank and generating flash steam. This flash steam can be used for pre-heating boiler feed water or for any other purpose.

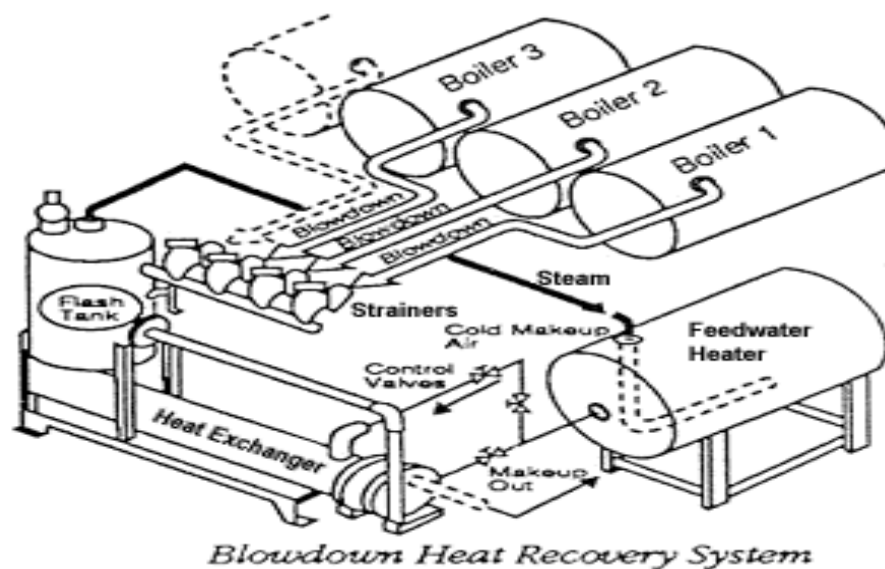


Figure 2.8: Blow down heat recovery system

Benefits of Blow down

Good boiler blow down control can significantly reduce treatment and operation al costs that include:

- Lower pre treatment costs
- Less make-up water consumption
- Reduced maintenance own time
- Increased boiler life
- Lower consumption of treatment chemicals

2.6. Boiler Water Treatment

Producing quality steam on demand depends on properly managed water treatment to control steam purity, deposits and corrosion. A boiler is the sump of the boiler system. It ultimately receives all of the pre-boiler contaminants. Boiler performance, efficiency, and service life are direct products of selecting and controlling feed water used in the boiler.

The boiler water must be sufficiently free of deposit forming solids to allow rapid and efficient heat transfer and it must not be corrosive to the boiler metal. Deposits and corrosion result in efficiency losses and may cause boiler tube failures and inability to produce steam.

Two major types of boiler water treatment are: Internal water treatment and External water treatment.

Internal Water Treatment

Internal treatment is carried out by adding chemicals to boiler to prevent the formation of scale by converting the scale-forming compounds to free-flowing sludge's, which can be removed by blow down. This method is limited to boilers, where feed water is low in hardness salts, to low pressures– high TDS content in boiler water is tolerated, and when only small quantity of water is required to be treated. If these conditions are not applied, then high rates of blow down are required to dispose the sludge. They become uneconomical from heat and water loss consideration.

Different waters require different chemicals. Sodium carbonate, sodium aluminate, sodium phosphate, sodium sulphite and compounds of vegetable or inorganic origin are all used for this purpose. Proprietary chemicals are available to suit various water conditions. The specialist must be consulted to determine the most suitable chemicals to use in each case. Internal treatment alone is not recommended.

External Water Treatment

External treatment is used to remove suspended solids, dissolved solids (particularly the calcium and magnesium ions which are major causes of scale formation) and dissolved gases (oxygen and carbon dioxide).

The external treatment processes available are: ion exchange; demineralization; reverse osmosis and de-aeration. Before any of these are used, it is necessary to remove suspended solids and colour from the raw water, because these may foul the resins used in the subsequent treatment sections.

Methods of pre-treatment include simple sedimentation in settling tanks or settling in clarifiers with aid of coagulants and flocculants. Pressure sand filters, with spray aeration to remove carbon dioxide and iron, may be used to remove metal salts from bore well water.

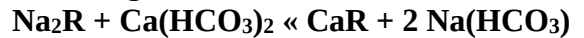
The first stage of treatment is to remove hardness salt and possibly non-hardness salts. Removal of only hardness salts is called softening, while total removal of salts from solution is called demineralization.

The processes are:

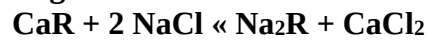
Ion-exchange process (Softener Plant)

In ion-exchange process, the hardness is removed as the water passes through bed of natural zeolite or synthetic resin and without the formation of any precipitate. The simplest type is 'base exchange' in which calcium and magnesium ions are exchanged for sodium ions. After saturation regeneration is done with sodium chloride. The sodium salts being soluble, do not form scales in boilers. Since base exchanger only replaces the calcium and magnesium with sodium, it does not reduce the TDS content, and blow down quantity. It also does not reduce the alkalinity.

Softening reaction



Regeneration reaction



Demineralization is the complete removal of all salts. This is achieved by using a "cation" resin, which exchanges the cations in the raw water with hydrogen ions, producing hydrochloric, sulphuric and carbonic acid. Carbonic acid is removed in degassing tower in which air is blown through the acid water. Following this, the water passes through an "anion" resin which exchanges anions with the mineral acid (e.g. sulphuric acid) and forms water. Regeneration of cations and anions is necessary at intervals using, typically, mineral acid and caustic soda respectively. The complete removal of silica can be achieved by correct choice of anion resin.

Ion exchange processes can be used for almost total demineralization if required, as is the case in large electric power plant boilers

De-aeration

In de-aeration (Figure 2.9), dissolved gases, such as oxygen and carbon dioxide, are expelled by preheating the feed water before it enters the boiler.

All natural waters contain dissolved gases in solution. Certain gases, such as carbon dioxide and oxygen, greatly increase corrosion. When heated in boiler systems, carbon dioxide (CO_2) and oxygen (O_2) are released as gases and combine with water (H_2O) to form carbonic acid, (H_2CO_3).

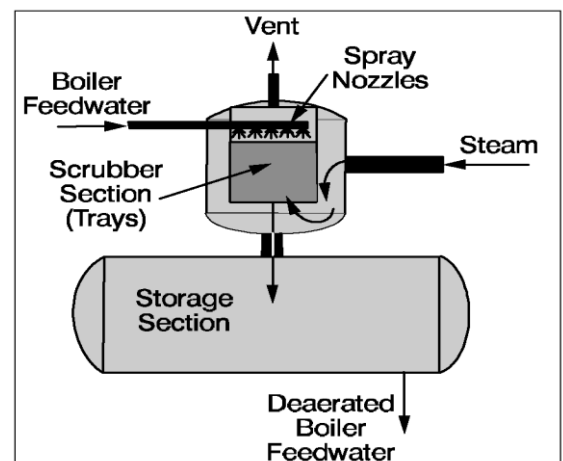


Figure 2.9: Deaerator

Removal of oxygen, carbon dioxide and other non-condensable gases from boiler feed water is vital to boiler equipment longevity as well as safety of operation. Carbonic acid corrodes metal reducing the life of equipment and piping. It also dissolves iron (Fe) which when returned to the boiler precipitates and causes scaling on the boiler and tubes. This scale not only contributes to reducing the life of the equipment but also increases the amount of energy needed to achieve heat transfer.

De-aeration can be done by mechanical de-aeration, by chemical de-aeration or by both together.

Mechanical de-aeration

Mechanical de-aeration for the removal of these dissolved gases is typically utilized prior to the addition of chemical oxygen scavengers. Mechanical de-aeration is based on Charles' and Henry's laws of physics. Simplified, these laws state that removal of oxygen and carbon dioxide can be accomplished by heating the boiler feed water, which reduces the concentration of oxygen and carbon dioxide in the atmosphere surrounding the feed water. Mechanical de-aeration can be the most economical. They operate at the boiling point of water at the pressure in the de-aerator. They can be of vacuum or pressure type.

The vacuum type of de-aerator operates below atmospheric pressure, at about 82 °C, can reduce the oxygen content in water to less than 0.02 mg/litre. Vacuum pumps or steam ejectors are required to maintain the vacuum.

The pressure-type de-aerators operates by allowing steam into the feed water through a pressure control valve to maintain the desired operating pressure, and hence temperature at a minimum of 105°C. The steam raises the water temperature causing the release of O₂ and CO₂ gases that are then vented from the system. This type can reduce the oxygen content to 0.005 mg/litre.

Where excess low-pressure steam is available, the operating pressure can be selected to make use of this steam and hence improve fuel economy. In boiler systems, steam is preferred for de-aeration because:

- Steam is essentially free from O₂ and CO₂
- Steam is readily available
- Steam adds the heat required to complete the reaction.

Chemical de-aeration

While the most efficient mechanical deaerators reduce oxygen to very low levels (0.005 mg/litre), even trace amounts of oxygen may cause corrosion damage to a system. Consequently, good operating practice requires removal of that trace oxygen with a chemical oxygen scavenger such as sodium sulfite or hydrazine. Sodium sulphite reacts with oxygen to form sodium sulphate, which increases the TDS in the boiler water and hence increases the blow down requirements and make-up water quality. Hydrazine reacts with oxygen to form nitrogen and water. It is invariably used in high pressures boilers when low boiler water solids are necessary, as it does not increase the TDS of the boiler water.

Reverse Osmosis

When solutions of differing concentrations are separated by a semi-permeable membrane, water from less concentrated solution passes through the membrane to dilute the liquid of high concentration, which is called osmosis. If the solution of high concentration is pressurized, the process is reversed and the water from the solution of high concentration flows to the weaker solution. This is known as reverse osmosis.

	The semi permeable nature of the membrane allows the water to pass much more readily than the dissolved minerals. Since the water in the less concentrated solution seeks to dilute the more concentrated solution, the water passage through the membrane generates a noticeable head difference between the two solutions. This head difference is a measure of the concentration difference of the two solutions and is referred to as the osmotic pressure difference.
	When a pressure is applied to the concentrated solution which is great that the osmotic pressure difference, the direction of water passage through the membrane <i>is reversed</i> and the process that we refer to as reverse osmosis is established. That is, the membrane's ability to selectively pass water is unchanged, only the direction of the water flow is changed.
	The feed water and <i>concentrate (reject stream) ports</i> illustrates a continuously operating RO system.

Figure 2.10: Reverse Osmosis

The quality of water produced depends upon the concentration of the solution on the high-pressure side and pressure differential across the membrane. This process is suitable for waters with very high TDS, such as sea water.

Recommended boiler and feed water quality

The impurities found in boiler water depend on the untreated feed water quality, the treatment process used and the boiler operating procedures. As a general rule, the higher the boiler operating pressure, the greater will be the sensitivity to impurities. Recommended feed water and boiler water limits are shown in Table 2.2 and Table 2.3.

Table 2.2: Recommended feed water limits

Factor	Up to 20Kg/cm ²	21 - 40Kg/cm ²	41 - 60Kg/cm ²
Total iron (max)ppm	0.05	0.02	0.01
Total copper (max)ppm	0.01	0.01	0.01
Total silica (max)ppm	1.0	0.3	0.1
Oxygen (max)ppm	0.02	0.02	0.01
Hydrazine residualppm	-	-	-0.02-0.04
0 pH at 25C	8.8-9.2	8.8-9.2	8.2-9.2
Hardness	1.0	0.5	-

The impurities found in boiler water depend on the untreated feed water quality, the treatment process used and the boiler operating procedures. As a general rule, the higher is the boiler operating pressure, the greater will be the sensitivity to impurities.

Table 2.3: Recommended boiler water limits (IS 10392, Year 1982)

Factor	Upto 20Kg/cm ²	21 - 40Kg/cm ²	41 - 60Kg/cm ²
TDS	3000-3500	1500-2000	500-750
Total iron dissolved solids ppm	500	200	150
Specific electrical conductivity at 25 °C (mho)	1000	400	300
Phosphate residual ppm	20-40	20-40	15-25
pH at 25 °C	10-10.5	10-10.5	9.8-10.2
Silica (max) ppm	25	15	10

2.7. Energy Conservation Opportunities

The various energy efficiency opportunities in boiler system can be related to combustion, heat transfer, avoidable losses, high auxiliary power consumption, water quality and blow down.

Examining the following factors can indicate if a boiler is being run to maximize its efficiency:

1. Stack Temperature

The stack temperature should be low as possible. However, it should not be so low that water vapor in the exhaust condenses on the stack walls. This is important in fuels containing significant sulphur as low temperature can lead to sulphur dew point corrosion. Stack temperatures greater than 200°C indicates potential for recovery of waste heat. It also indicates the scaling of heat transfer / recovery equipment and hence the urgency of taking an early shutdown for water / flue side cleaning.

2. Feed Water Preheating using Economiser

Typically, the flue gases leaving a modern 3-pass shell boiler are at temperatures of 200 to 300°C. Thus, there is a potential to recover heat from these gases. The flue gas exit temperature from a boiler is usually maintained at a minimum of 200°C, so that the sulphur oxides in the flue gas do not condense and cause corrosion in heat transfer surfaces. When a clean fuel such as natural gas, LPG or gas oil is used, the economy of heat recovery must be worked out, as the flue gas temperature may be well below 200 °C.

The potential for energy saving depends on the type of boiler installed and the fuel used. For a typically older model shell boiler, with a flue gas exit temperature of 260 °C, an economizer could be used to reduce it to 200 °C, increasing the feed water temperature by 15 °C. Increase in overall thermal efficiency would be in the order of 3%. For a modern 3-pass shell boiler firing natural gas with a flue gas exit temperature of 140 °C a condensing economizer would reduce the exit temperature to 65 °C increasing thermal efficiency by 5%.

3. Combustion Air Pre heat

Combustion air preheating is an alternative to feed water heating. In order to improve thermal efficiency by 1%, the combustion air temperature must be raised by 20°C. Most gas and oil burners used in a boiler plant are not designed for high air preheat temperatures.

Modern burners can withstand much higher combustion air preheat, so it is possible to consider such units as heat exchangers in the exit flue as an alternative to an economizer, when either space or a high feed water return temperature make it viable.

4. Incomplete Combustion

Incomplete combustion can arise from a shortage of air or surplus of fuel or poor distribution of fuel. It is usually obvious from the colour or smoke, and must be corrected immediately.

In the case of oil and gas fired systems, CO or smoke (for oil fired systems only) with normal or high excess air indicates burner system problems. A more frequent cause of incomplete combustion is the poor mixing of fuel and air at the burner. Poor oil fires can result from improper viscosity, worn tips, carbonization on tips and deterioration of diffusers or spinner plates.

With coal firing, unburned carbon can comprise a big loss. It occurs as grit carry-over or carbon-in-ash may amount to more than 2% of the heat supplied to the boiler. Non uniform fuel size could be one of the reasons for incomplete combustion. In chain grate stokers, large lumps will not burnout completely, while small pieces and fines may block the air passage, thus causing poor air distribution. In sprinkler stokers, stoker grate

condition, fuel distributors, wind box air regulation and over-fire systems can affect carbon loss. Increase in the fines in pulverized coal also increases carbon loss.

5. Excess Air Control

The Table 2.4 gives the theoretical amount of air required for combustion of various types of fuel.

Table 2.4: Theoretical combustion data – common boiler fuels

Fuel	kg of air req./kg of fuel	kg of flue gas/kg of fuel	m3 of flue/kg of fuel	Theoretical CO ₂ % in dry flue gas	CO ₂ % in flue gas achieved in practice
Solid Fuels					
Bagasse	3.2	3.43	2.61	20.65	10-12
Coal (bituminous)	10.8	11.7	9.40	18.70	10-13
Lignite	8.4	9.10	6.97	19.40	9 -13
Paddy Husk	4.6	5.63	4.58	19.8	14-15
Wood	5.8	6.4	4.79	20.3	11.13
Liquid Fuels					
Furnace Oil	13.90	14.30	11.50	15.0	9-14
LSHS	14.04	14.63	10.79	15.5	9-14

Excess air is required in all practical cases to ensure complete combustion, to allow for the normal variations in combustion and to ensure satisfactory stack conditions for some fuels. The optimum excess air level for maximum boiler efficiency occurs when the sum of the losses due to incomplete combustion and loss due to heat in flue gases is minimum. This level varies with furnace design, type of burner, fuel and process variables. It can be determined by conducting tests with different air fuel ratios.

Typical values of excess air supplied for various fuels are given in Table 2.5.

Table 2.5: Excess air supplied for various fuels

Fuel	Type of Furnace or Burners	Excess Air (% by wt.)
Pulverised coal	Completely water-cooled furnace for slag-tap or dry-ash removal	15-20
	Partially water-cooled furnace for dry-ash removal	15-40
Coal	Spreader stoker	30-60
	Water-cooler vibrating-grate stokers	30-60
	Chain-grate and traveling-grate stokers	15-50
	Underfeed stoker	20-50
Fuel oil	Oil burners, register type	15-20
	Multi-fuel burners and flat-flame	20-30
Natural gas	High pressure burner	5-7
Wood	Dutch over (10-23% through grates) and Hoff t type	20-25
Bagasse	All furnaces	25-35
Black liquor	Recovery furnaces for draft and soda-pulping processes	30-40

Controlling excess air to an optimum level always results in reduction in flue gas losses; for every 1% reduction in excess air there is approximately 0.6% rise in efficiency.

Various methods are available to control the excess air:

- Portable oxygen analysers and draft gauges can be used to make periodic readings to guide the operator to manually adjust the flow of air for optimum operation. Excess air reduction up to 20% is feasible.
- The most common method is the continuous oxygen analyzer with a local read out mounted draft gauge, by which the operator can adjust air flow. A further reduction of 10-15% can be achieved over the previous system.
- The same continuous oxygen analyzer can have a remote controlled pneumatic damper positioned, by which the read outs are available in a control room. This enables an operator to remotely control a number of firing systems simultaneously.

The most sophisticated system is the automatic stack damper control, whose cost is really justified only for large systems.

6. Radiation and Convection Heat Loss

The external surfaces of a shell boiler are hotter than the surroundings. The surfaces thus lose heat to the surroundings depending on the surface area and the difference in temperature between the surface and the surroundings.

The heat loss from the boiler shell is normally a fixed energy loss, irrespective of the boiler output. With modern boiler designs, this may represent only 1.5% on the gross calorific value at full rating, but will increase to around 6%, if the boiler operates at only 25 percent output.

Repairing or augmenting insulation can reduce heat loss through boiler walls and piping.

7. Automatic Blow down control

Uncontrolled continuous blow down is very wasteful. Automatic blow down controls can be installed that sense and respond to boiler water conductivity and pH. A 10% blow down in a 15 kg/cm² boiler results in 3% efficiency loss.

8. Reduction of Scaling and Soot losses

In oil and coal-fired boilers, soot build upon tubes acts as an insulator against the heat transfer. Any such deposits should be removed on a regular basis. Elevated stack temperatures may indicate excessive soot buildup. Also same result will occur due to scaling on the waterside.

High exit gas temperatures at normal excess air indicate poor heat transfer performance. This condition can result from a gradual build-up of gas-side or waterside deposits. Water side deposits require a view of water treatment procedures and tube cleaning to remove deposits. An estimated 1% efficiency loss occurs with every 4.4 °C increase in stack temperature.

Stack temperature should be checked and recorded regularly as an indicator of soot deposits. When the flue gas temperature raises about 20°C above the temperature for a newly cleaned boiler, it is time to remove the soot deposits. It is, therefore, recommended to install a dial type thermometer at the base of the stack to monitor the exhaust flue gas temperature.

Every millimeter thickness of soot coating increases the stack temperature by about 55°C. It is also estimated that 3mm of soot can cause an increase in fuel consumption by 2.5%. Periodic off-line cleaning of radiant furnace surfaces, boiler tube banks, economizers and air heaters may be necessary to remove stubborn deposits.

9. Reduction of Boiler Steam Pressure

This is an effective means of reducing fuel consumption, if permissible, by as much as 1 to 2%. Lower steam pressure gives a lower saturated steam temperature and without stack heat recovery, a similar reduction in the temperature of the flue gas temperature results.

Steam is generated at pressures normally dictated by the highest pressure /temperature requirements for a particular process. In some cases, the process does not operate all the time, and there are periods when the boiler pressure could be reduced. The energy manager should consider pressure reduction carefully, before recommending it. Adverse effects, such as an increase in water carry over from the boiler owing to pressure reduction, may negate any potential saving. Pressure should be reduced in stages, and no more than a 20 percent reduction should be considered.

10. Variable Speed Control for Fans, Blowers and Pumps

Variable speed control is an important means of achieving energy savings. Generally, combustion air control is effected by throttling dampers fitted at forced and induced draft fans. Though dampers are simple means of control, they lack accuracy, giving poor control characteristics at the top and bottom of the operating range. In general, if the load characteristic of the boiler is variable, the possibility of replacing the dampers by a VSD should be valued.

11. Effect of Boiler Loading on Efficiency

The maximum efficiency of the boiler does not occur at full load, but at about two-thirds of the full load. If the load on the boiler decreases further, efficiency also tends to decrease. At zero output, the efficiency of the boiler is zero, and any fuel fired is used only to supply the losses. The factors affecting boiler efficiency are:

- As the load falls, so does the value of the mass flow rate of the flue gases through the tubes. This reduction in flow rate for the same heat transfer area reduced the exit flue gas temperatures by a small extent, reducing the sensible heat loss.
- Below half load, most combustion appliances need more excess air to burn the fuel completely. This increases the sensible heat loss.

The net effect of these factors is to produce a load / efficiency curve. It has been generally noticed that the fall in efficiency begins to become serious below about a quarter load, and as far as possible, operation of boilers below this level should be avoided.

12. Proper Boiler Scheduling

Since the optimum efficiency of boilers occurs at 65-85% of full load, it is usually more efficient, on the whole, to operate a fewer number of boilers at higher loads, than to operate a large number at low loads.

13. Boiler Replacement

The potential savings from replacing a boiler depend on the anticipated change in overall efficiency. A change in a boiler can be financially attractive if the existing boiler is:

- old and inefficient
- not capable of firing cheaper substitution fuel
- over or under-sized for present requirements
- not designed for ideal loading conditions

The feasibility study should examine all implications of long-term fuel availability and company growth plans. All financial and engineering factors should be considered. Since boiler plants traditionally have a useful life of well over 25 years, replacement must be carefully studied.

2.8. Case Study

Installing Boiler Economiser

A paper mill fitted an economizer to existing boiler. The general specification of the boiler is given below:

Boiler capacity (T/h)	Feed water Temp. (°C)	Steam pressure (bar)	Fuel oil
8	110	18	No.6

The thermal efficiency of the boiler was measured and calculated by the indirect method using flue gas analyser and data logger. The result is summarized below:

Thermal efficiency	:	80.99%
Flue gas temperature	:	315°C
CO ₂ %	:	13
CO (PPM)	:	167

The temperature in the flue gas is in the range of 315 to 320°C. The waste heat in the flue gas is recovered by installing an economizer, which transfers waste heat from the flue gases to the boiler feed water. This resulted in a rise in feed water temperature by about 26°C.

Basic Data

Average quantity of steam generated	:	5.04 T/h
Average flue gas temperature	:	315°C
Average steam generation / kg of fuel oil	:	16.05 kg

Feed water inlet temperature	: 110°C
Fuel oil supply rate	: 314kg/h
Flue gas quantity	: 17.4 kg/kg of fuel

Cost Economics

Quantity of flue gases	: 5463.6kg/h
Quantity of heat available in the flue gases	: 5463.6 x 0.25 x (315-200) = 157078 kCal/h
Rise in the feed water temperature	: 26°C
Heat required for pre-heating the feed water	: 5040 x 1.065 x 26 = 139557 kCal/h
Saving in terms of HSD fuel	: 139557 kCal/h / 10000 kCal/kg = 14 kg/h
Annual operating hours	: 8600
Annual savings of fuel oil	: 120400 kg

Conclusion

Through recovery of waste heat by installation of an economizer, the paper mill was able to save 14 kg/hr of HSD fuel, which amounts to about 1,20,400 kg of fuel oil per annum.

Examples:

Problem -1:

The efficiency of a boiler on GCV basis is 85%. The fuel contains 1.0 % moisture and 12 % hydrogen. The GCV of fuel is 10,500 Kcal/kg. What is the boiler efficiency on the basis of net calorific value?

Solution:

$$\text{NCV} = \text{GCV} - \left[9 \times \frac{\% \text{age of Hydrogen in fuel}}{100} + \frac{\% \text{age of moisture in fuel}}{100} \right] \times 584$$

$$\begin{aligned} \text{NCV} &= 10500 - \left[9 \times \frac{12}{100} + \frac{1.0}{100} \right] \times 584 \\ &= 10500 - [9 \times 0.12 + 0.01] \times 584 \\ &= 10500 - 636.56 \\ &= 9863.44 = 9863 \text{ kCal /kg} \end{aligned}$$

$$\begin{aligned}\text{Boiler efficiency on NCV} &= \frac{85}{9863} \times 10500 \\ &= 90.5\%\end{aligned}$$

Problem -2:

A textile plant is using furnace oil as fuel for firing in the boiler, generating steam on an average of 30T/hr. The unit has decided to switch over to natural gas as fuel to concern for emissions reduction. The boiler feed water temperature is 60°C and the enthalpy of steam is 660 kCal/kg. The other data are as under:

Furnace oil :

GCV of furnace oil	: 10200kCal/kg
%Carbon in furnace oil	: 84
Efficiency of furnace oil	: 82%

Natural Gas :

Gross Calorific value of Natural gas	: 9500kCal/ (Sm ³)
Density of natural gas	: 0.8kg/Sm ³
% carbon in natural gas	: 74
Annual operating hrs.	: 8000
Efficiency of natural gas boiler	: 86%

Calculate the Reduction in GHG emissions?

Solution:

Furnace oil fired boiler:

Kg of CO₂/kg of oil = 0.84* (44/12) = 3.08
Heat output of boiler = 30000*(660-60) = 18 million kCal/hr.
Heat input to boiler = 18/0.82 = 21.95 million kCal/hr
Furnace oil consumption = 21.95*10⁶/ 10200 = 2.152T/hr.
CO₂ emission with furnace oil = 2,152* 3.08 = 6.628T/hr.

Gas fired Boiler:

Kg of CO₂/kg of gas = 0.74* (44/12) = 2.71
Heat input to boiler = 18/0.86 = 20.93 million kCal/hr
Natural gas consumption = 20.93* 10⁶/9500 = 2203 Sm³/hr
= 2203*0.8/1000 = 1.7624T/hr.
CO₂ emission with natural gas= 1.7624*2.71 = 4.776T/hr.

Annual CO₂ emission reduction = $(6.628 - 4.776) \times 8000 = 14816 \text{ T/y}$

Problem -3:

Oil fired Boiler is generating 100 TPH of steam at 85% efficiency, operating 330 days in a year. Management has installed a water treatment plant at Bangladeshi Taka (BDT) 1.16Crore investment for reducing the TDS in boiler feed from 450 ppm to 150 ppm. The maximum permissible limit of TDS in the boiler is 3000 ppm and make up water is 10%. Temperature of blow down water is 175°C and boiler feed water temperature is 45°C. Calorific value of Fuel oil is 1200 kCal/kg.

Calculate the payback period if the cost of fuel is 23150 Bangladeshi Taka / Ton.

Solution:

$$\text{Blow down \%} = \frac{(\text{Feed water TDS} \times \% \text{ make up water}) \times 100}{(\text{Maximum permissible TDS in boiler water} - \text{Feed water TDS})}$$

$$\begin{aligned} \text{Initial blow down} &= 450 \times 10 / (3000 - 450) \\ &= 1.76 \% \end{aligned}$$

$$\begin{aligned} \text{Improved blow down} &= 150 \times 10 / (3000 - 150) \\ &= 0.53 \% \end{aligned}$$

$$\begin{aligned} \text{Reduction in blow down} &= 1.76 - 0.53 \\ &= 1.24 \% \end{aligned}$$

$$\begin{aligned} \text{Reduction in blow down} &= 1.24 \times 100 \times 1000 / 100 \\ &= 1238 \text{ kg/hr} \end{aligned}$$

Specific heat of water is 1 kCal/kg°C

$$\begin{aligned} \text{Heat savings} &= m \times C_p \times (T_1 - T_2) &= 1238 \times 1 \times (175 - 45) \\ & &= 160991 \text{ kcal/hr} \end{aligned}$$

$$\text{Fuel oil saving} = 160991 / (1200 \times 0.85) = 157.83 \text{ kg/hr}$$

$$\begin{aligned} \text{Annual fuel oil savings} &= 157.83 \times 24 \times 330 / 1000 \\ &= 1250 \text{ MT / annum} \end{aligned}$$

$$\text{Fuel oil cost savings} = 1250 \times 23150 = \text{BDTaka } 289.4 \text{ Lakh}$$

Investment on water treatment plant = Bangladeshi Taka 1.16Crore

$$\text{Payback period} = 1.16 / 2.894$$

$$\text{Payback period} = 0.4 \text{ years (or) 5 months}$$

3. STEAM SYSTEM

3.1. Introduction

Steam has been a popular mode of conveying energy since the industrial revolution. Steam is used for generating power and also used in process industries such as sugar, paper, fertilizer, refineries, petrochemicals, chemical, food, synthetic fibre and textiles. The following characteristics of steam make it so popular and useful to the industry:

- Highest specific heat and latent heat
- Highest heat transfer coefficient
- Easy to control and distribute
- Cheap and inert

3.2. Properties of Steam

Water can exist in the form of solid, liquid and gas as ice, water and steam respectively. If heat energy is added to water, its temperature rises until a value is reached at which the water can no longer exist as a liquid. We call this the "saturation" point and with any further addition of energy, some of the water will boil off as steam. This evaporation requires relatively large amounts of energy and while it is being added, the water and the steam released are both at the same temperature. Equally, if steam is made to release the energy that was added to evaporate it, then the steam will condense and water at same temperature will be formed.

Liquid Enthalpy

Liquid enthalpy is the "Enthalpy"(heat energy) in the water when it has been raised to its boiling point to produce steam, and is measured in kCal/kg, its symbol is h_f . (also known as "Sensible Heat").

*The heat required to change the temperature of a substance is called its **sensible heat**. If 1kg of water in a vessel at 25°C i.e. containing heat value of 25kCal is heated by adding 75kCal, the water is brought to boiling point of 100°C.*

Enthalpy of Evaporation (Heat Content of Steam)

The Enthalpy of evaporation is the heat energy to be added to the water (when it has been raised to its boiling point) in order to change it into steam. There is no change in temperature, the steam produced is at the same temperature as the water from which it is produced, but the heat energy added to the water changes its state from water into steam at the same temperature.

When the steam condenses back in to water, it gives up its enthalpy of evaporation, which it had acquired on changing from water to steam. The enthalpy of evaporation is measured in kCal/kg. Its symbol is h_{fg} . Enthalpy of evaporation is also known as latent heat.

*To change the water to steam an additional 540kcal would be required. This quantity of heat required to change a chemical from the liquid to the gaseous state is called **latent heat**.*

For a boiler is operating at a pressure of 8kg/cm^2 , steams aturation temperature is 170°C , and steam enthalpy or total heat of dry saturated steam is given by:

$$h_f + h_{fg} = 171.35 + 489.46 = 660.81 \text{ kCal/kg.}$$

If the same steam contains 4% moisture, the total heat of steam is given by:

$$171.35 + 0.96 \times 489.46 = 641.23 \text{ kCal/kg}$$

The temperature at which water boils, also called as boiling point or **saturation temperature** increases as the pressure increases. When water under pressure is heated its saturation temperature rises above 100°C . From this, it is evident that as the steam pressure increases, the usable heat energy in the steam (enthalpy of evaporation), which is given up when the steam condenses, actually decreases. The total heat of dry saturated steam or enthalpy of saturated steam is given by sum of the two enthalpies $h_f + h_{fg}$ (Refer Table 3.1 and figure 3.1). When the steam contains moisture, the total heat of steam will be $h_g = h_f + q h_{fg}$ where q is the dryness fraction.

The temperature of saturated steam is the same as the water from which it is generated and corresponds to a fixed and known pressure. Superheat is the addition of heat to dry saturated steam without increase in pressure. The temperature of superheated steam, expressed as degrees above saturation corresponding to the pressure, is referred to as the degrees of **superheat**.

The Steam Phase Diagram

The data provided in the steam tables can also be expressed in a graphical form. Figure 3.1 illustrates the relationship between the enthalpy and the temperature at various different pressures, and is known as a phase diagram.

As water is heated from 0°C to its saturation temperature, its condition follows the saturated liquid line until it has received all of its liquid enthalpy, h_f , (**A - B**).

If further heat continues to be added, it then changes phase to saturated steam and continues to increase in enthalpy while remaining at saturation temperature, h_{fg} , (**B - C**).

As the steam/water mixture increases in dryness, its condition moves from the saturated liquid line to the saturated vapour line. Therefore at a point exactly halfway between these two states, the dryness fraction (X) is 0.5. Similarly, on the saturated vapour line the steam is 100% dry.

Once it has received all of its enthalpy of evaporation, it reaches the saturated vapour line. If it continues to be heated after this point, the temperature of the steam will begin to rise as superheat is imparted (**C - D**).

The saturated liquid and saturated vapour lines enclose a region in which a steam/water mixture exists - wet steam. In the region to the left of the saturated liquid line only water exists, and in the region to the right of the saturated vapour line only superheated steam exists.

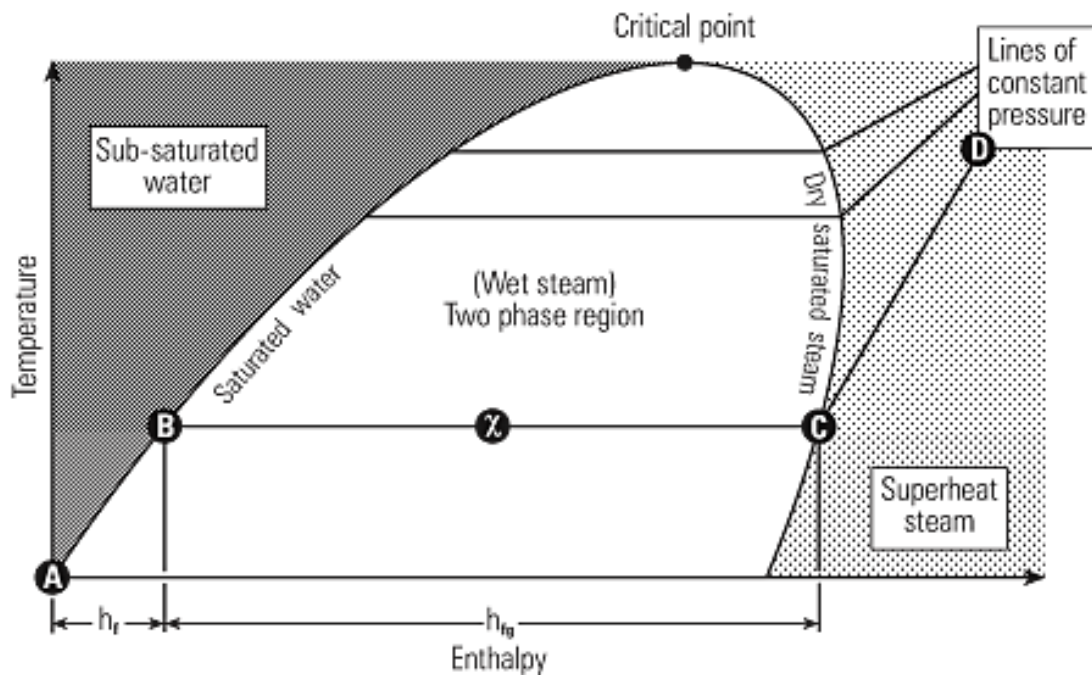


Figure 3.1: Steam Phase Diagram

The point at which the saturated liquid and saturated vapour lines meet is known as the critical point. As the pressure increases towards the critical point the enthalpy of evaporation decreases, until it becomes zero at the critical point. This suggests that water changes directly into saturated steam at the critical point.

Above the critical point only gas may exist. The gaseous state is the most diffuse state in which the molecules have an almost unrestricted motion, and the volume increases without limit as the pressure is reduced.

The critical point is the highest temperature at which liquid can exist. Any compression at constant temperature above the critical point will not produce a phase change. Compression at constant temperature below the critical point however, will result in liquefaction of the vapour as it passes from the superheated region into the wet steam region. The critical point occurs at 374.15°C and 221.2 bar (a) for steam. Above this pressure the steam is termed supercritical and no well-defined boiling point applies.

Table 3.1: Extract From the Steam Tables

Pressure (kg/cm ²)	Temperature °C	Enthalpy in kcal/kg			Specific volume (m ³ /kg)
		Water (h _f)	Evaporation (h _{fg})	Steam (h _g)	
1	100	100.09	539.06	639.15	1.673
2	120	119.92	526.26	646.18	0.901
3	133	133.42	517.15	650.57	0.616
4	143	143.70	509.96	653.66	0.470
5	151	152.13	503.90	656.03	0.381
6	158	159.33	498.59	657.92	0.321
7	164	165.67	493.82	659.49	0.277
8	170	171.35	489.46	660.81	0.244

3.3 Steam Distribution System

The steam distribution system is the essential link between the steam generator and the steam user. Whatever the source, an efficient steam distribution system is essential if steam of the right quality and pressure is to be supplied, in the right quantity, to the steam using equipment. Installation and maintenance of the steam system are important issues, and must be considered at the design stage.

The following factors have to be considered in the design of a good Steam Distribution System.

- General Layout
- Pipe sizing and Design
- Pressure Reducing and De-superheating Station
- Air Venting (as given in sub-section 3.7)
- Steam Pipe Insulation (as given in sub-section 3.7)

General Layout

General layout and location of steam consuming equipment is of great importance in efficient distribution of steam. Steam pipes should be laid by the shortest possible distance rather than to follow a building layout or road etc. However, this may come in the way of aesthetic design and architect's plans and a compromise may be necessary while laying new pipes.

Steam Pipe Sizing and Design

Any modification and alteration in the existing steam piping, for supplying higher quality steam at right pressure and quantity must consider the following points:

Pipe Sizing

The objective of the steam distribution system is to supply steam at the correct pressure to the point of use. It follows therefore, that pressure drop through the distribution system is an important feature.

The distribution pressure of steam is influenced by a number of factors, but is limited by:

- The maximum safe working pressure of the boiler
- The minimum pressure required at the plant

As steam passes through the distribution pipe work, it will inevitably lose pressure due to:

- Frictional resistance within the pipe work
- Condensation within the pipe work as heat is transferred to the environment.

Therefore allowance should be made for this pressure loss when deciding upon the initial distribution pressure.

Proper sizing of steam pipelines help in minimizing pressure drop. The velocities for various types of steam are:

Superheated	50-70 m/sec
Saturated	30-40 m/sec
Wet or Exhaust	20-30 m/sec

For fluid flow to occur, there must be more energy at Point 1 than Point 2 (Figure 3.2). The difference in energy is used to overcome frictional resistance between the pipe and the flowing fluid.

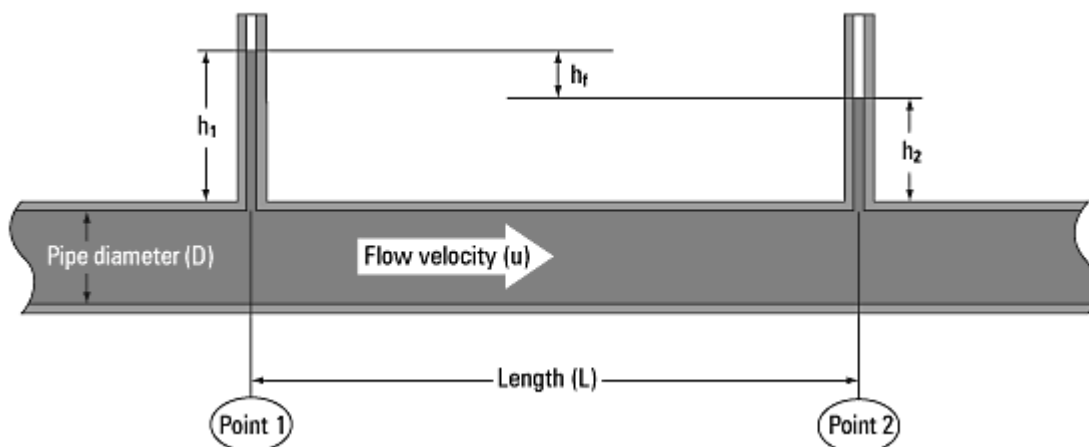


Figure 3.2: Pressure drop in steam pipes

This is illustrated by the equation,

$$h_f = \frac{4 f L u^2}{2 g D}$$

Where,

h_f = Head loss to friction (m)

f = Friction factor (dimensionless), usually obtained from charts

L = Length (m)

u = Flow velocity (m/s)

g = Gravitational constant (9.81 m/s²)

D = Pipe diameter (m)

Example-1: Pressure drop calculation

Determine the difference in pressure between two points 1 km apart in a 150 mm bore horizontal pipework system. The water flowrate is 45 m³/h at 15°C and the friction factor for this pipe is taken as 0.005.

$$\text{Velocity (m/s)} = \frac{\text{Volume flowrate (m}^3/\text{s)}}{\text{Crosssectional area (m}^2\text{)}}$$

$$\text{Velocity (m/s)} = \frac{45(\text{m}^3/\text{hr}) \times 4}{3600 \text{ s/hr} \times \pi \times 0.15^2}$$

$$\text{Velocity} = 0.71 \text{ m/s}$$

$$h_f = \frac{4 f L u^2}{2 g D}$$

$$h_f = \frac{4 \times 0.005 \times 1000 \times 0.71^2}{2 \times 9.81 \times 0.15}$$

$$h_f = 3.43 \text{ m} \approx 0.34 \text{ bar}$$

Example-2: Determining the pipe size

A process requires 5000 kg/h of dry saturated steam at 7 kg/cm² (g). For the flow velocity not to exceed 25 m/s, determine the pipe size.

$$\text{Flow velocity} = 25 \text{ m/s}$$

$$\text{Specific volume at } 7 \text{ kg/cm}^2 = 0.24 \text{ m}^3/\text{kg}$$

$$\text{Mass flow rate} = 5000 \text{ kg/hr or } 1.389 \text{ kg/s}$$

$$\begin{aligned} \text{Volumetric flowrate} &= 1.389 \times 0.24 \\ &= 0.333 \text{ m}^3/\text{s} \end{aligned}$$

Therefore, using:

$$\text{Crosssectional area} = \frac{\text{Volumetric flowrate}}{\text{Flow velocity}}$$

$$\frac{\pi \times D^2}{4} = \frac{\text{Volumetric flowrate}}{\text{Flow velocity}}$$

$$D^2 = \frac{4 \times \text{Volumetric flowrate}}{\pi \times \text{Flow velocity}}$$

$$D = \sqrt{\frac{4 \times \text{Volumetric flowrate}}{\pi \times \text{Flow velocity}}}$$

$$D = \sqrt{\frac{4 \times 0.333}{\pi \times 25}}$$

$$D = 0.130 \text{ m or } 130 \text{ mm}$$

Since the steam velocity must not exceed 25 m/s, the pipe size must be at least 130 mm; the nearest commercially available size, 150 mm, would be selected.

In practice whether for water pipes or steam pipes, a balance is drawn between pipe size and pressure loss. The steam piping should be sized, based on permissible velocity and the available pressure drop in the line. Selecting a higher pipe size will reduce the pressure drop and thus the energy cost. However, higher pipe size will increase the initial installation cost. By use of smaller pipe size, even though the installation cost can be reduced, the energy cost will increase due to higher-pressure drop. It is to be noted that the pressure drop change will be inversely proportional to the 5th power of diameter change. Hence, care should be taken in selecting the optimum pipe size.

Guide for proper drainage and layout of steam lines:

1. The steam mains should be run with a falling slope of not less than 125 mm for every 30 metres length in the direction of the steam flow.
2. Drain points should be provided at intervals of 30-45 metres along the main.
3. Drain points should also be provided at low points in the mains and where the steam main rises. Ideal locations are the bottom of expansion joints and before reduction and stop valves.
4. Drain points in the main lines should be through an equal tee connection only.
5. It is preferable to choose open bucket or TD traps on account of their resilience.
6. The branch lines from the mains should always be connected at the top. Otherwise, the branch line itself will act as a drain for the condensate.
7. Insecure supports as well as an alteration in level can lead to formation of water pockets in steam, leading to wet steam delivery. Providing proper vertical and support hangers helps overcome such eventualities.
8. Expansion loops are required to accommodate the expansion of steam lines while starting from cold.
9. To ensure dry steam in the process equipment and in branch lines, steam separators can be installed as required.

Pressure Reducing De-superheating Station

A reduction in steam pressure through a pressure reducing valve (PRV) is an isenthalpic process. Saturated steam when reduced to a lower pressure results in superheated steam. Since the process requires only saturated steam, desuper heating is often required, to compensate for superheat gained in PRV application due to isenthalpic expansion. Pressure reduction and desuper heating of steam or conditioning of steam is done in many process industries to suit process requirement. This is due to the fact that steam is produced in a boiler economically at higher pressure and temperature. Generally, the temperature of the steam after desuper heating will be closer to saturation temperature for heat transfer applications.

The desuper heating of steam is done by spraying water through a spray nozzle into a pipe. Normally, the desuper heating is done by automatic control system, using a control device for spraying water, which takes the feedback from the temperature control loop.

3.4. Efficient Steam Utilization

In a steam system the major scope for improving energy efficiency lies in the utilization part. The steam generation and distribution efficiencies are fairly high at more than 80% whereas the utilization efficiency is only at 47%.

When viewed from the standpoint of being a heat medium, steam has superior properties not offered by other heat mediums. Steam provides for even and rapid heating.

In the case of saturated steam, if the steam pressure is known, then the steam temperature may be determined. Pressure changes instantaneously within a space. When saturated steam condenses, it condenses at the saturation temperature, and the saturated water (condensate) formed is of the same temperature as the saturated steam. This means that if the pressure at the heat transfer surface (the jacket or coil interior of the equipment) is held at a constant, continuous heating will be able to take place at the same temperature at every part of the heat transfer surface.

The amount of the heat transfer is indicated by the heat transfer coefficient (= film coefficient of heat transfer). The unit is $[W/m^2 K]$.

$W = J/sec$, so if heat exchange takes place on the same heat transfer surface area and with the same temperature difference, the larger the heat transfer rate, the shorter the time required for heating.

The rough values for the heat transfer rates of hot water and steam are as follows:

- The rate at which heat is transferred to the heat transfer surface of a heat exchanger using hot water as the heat source:
1000 — 6000 $[W/m^2 K]$
- The rate at which heat is transferred to the heat transfer surface of a heat exchanger using steam as the heat source:
6000 — 15000 $[W/m^2 K]$

In actual heating situations, the heat transfer process will be a combination of the mechanism of heat transfer within the walls of the heat exchanger and the mechanism of heat transfer from the wall surface of the heat exchanger to the product being heated.

Steam provides rapid heating because the transfer of heat caused by the process of condensing. The latent heat contained in steam is released in the instant the steam condenses into liquid phase. The amount of latent heat released is 2 – 5 times greater than the amount of sensible heat in the hot water (saturated water) after condensation. This latent heat is released instantaneously and is transferred by means of a heat exchanger to the product being heated.

In contrast, hot water and oil are used in convective heating, which does not involve a phase change. Instead, the heat medium reduces its own temperature in order to transfer heat to the product being heated. A mainstream in industry is the use of forced-convection by means of equipment such as a pump to create the flow against the heat transfer surface.

Example-3: Steam Utilization

1) A milk evaporator uses a steam jacketed kettle, in which milk is batch-processed at atmospheric pressure. The kettle has a 680 kg per batch capacity. Milk is heated from a temperature of 26 °C to 100 °C, where 25% of its mass is then driven off as vapor. Determine the amount of 1 kg/cm² (g) steam required per batch, not including the heating of

the kettle itself. (Specific heat of milk is $0.90 \text{ kcal/kg}^\circ\text{C}$). The latent heat of steam at 1 kg/cm^2 is 525 kcal/kg .

Solution:

$$\begin{aligned}\text{Quantity of water evaporated from milk} &= 680 \times 0.25 \\ &= 170 \text{ kg} \\ \text{/batch}\end{aligned}$$

Heat required to raise the temperature of milk from 26 to 100°C

$$\begin{aligned}&= 680 \times 0.9 \times (100 - 26) \\ &= 45288 \text{ kcal/batch}\end{aligned}$$

$$\begin{aligned}\text{Amount of heat required to evaporate } 170 \text{ kg of water} &= 170 \times 540 \\ &= 91800 \text{ kcal/batch}\end{aligned}$$

$$\begin{aligned}\text{Total heat required} &= 45288 + 91800 \\ &= 137088 \text{ kcal/batch}\end{aligned}$$

$$\begin{aligned}\text{Quantity of steam required} &= 137088/525 \\ &= 261 \text{ kg/batch}\end{aligned}$$

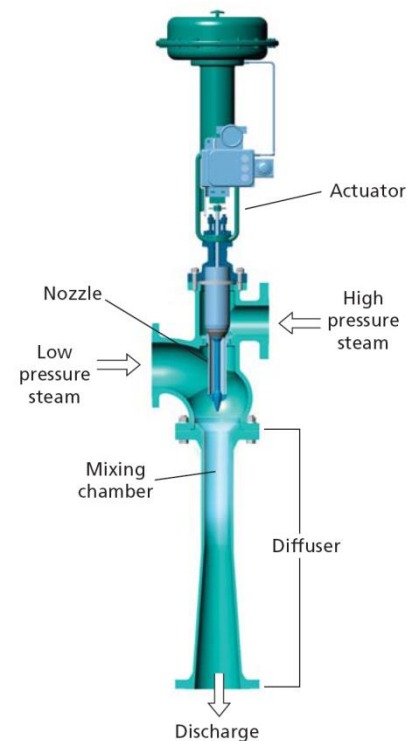


Figure 3.3: Thermocompressor

In many of the steam utilization equipment where condensate comes out at high pressure, a major portion of it flashes into low pressure steam which goes wasted. Using a thermo compressor (Figure 3.3) it becomes feasible to compress this low pressure steam by high pressure steam and reuse it as a medium pressure steam in the process. The major energy in steam is in its latent heat value and thus thermo compressing would give a large improvement in waste heat recovery.

Thermocompressors are designed to accurately mix lower-pressure steam with higher-pressure steam. The higher-pressure motive steam entrains the lower pressure steam and increases its pressure. The motive steam is introduced through the nozzle of the thermocompressor. As the nozzle opens, the high velocity motive steam draws the lower-pressure steam into the thermocompressor body. An exchange of momentum occurs as the steam flows are mixed and the mixed flow is accelerated to high velocity with a uniform profile in the mixing chamber of the thermocompressor. As the mixed flow enters the diffuser section, the diffuser flow area gradually increases to allow the velocity of the mixed flow to be reduced. As the velocity is reduced, the steam pressure increases. At the end of the diffuser, the discharge steam pressure is higher than the lower-pressure suction flow entering the thermocompressor. A typical application is in evaporators where the boiling steam is recompressed and used as heating steam.

Advantages of thermocompressors

- No condensation losses take place
- Thermal efficiency of the system is extremely high

- Entrainment of low pressure steam results in substantial savings
- No moving parts and hence maintenance needs are minimal
- No major operational charges
- Low space requirement
- Insensitive to fouling
- High operating reliability

Dryers

Drying is a process by which a liquid (commonly water) is removed from a material. This is usually achieved by applying heat, typically steam and/or the flow of carrier gas (commonly air) through or over the surface of the material (Figure 3.4). The objective of drying is to form a product that meets a water-content specification, so the amount of water removed depends on the desired product.

The basic drying energy requirement is the latent heat needed to evaporate the water. Clearly, this depends on the amount of water being evaporated. In most cases, the product material, the carrier gas and the equipment also need to be hot. So the total energy required includes:

- Heat leaving the dryer in the exhaust flow. This includes the latent heat of the water evaporated, but the sensible heat of the hot gas can also be significant.
- Heat lost from equipment and ducting. However good the insulation, there is always some heat loss.
- Heat leaving the dryer as hot product.
- Motive power for fans and conveyors.

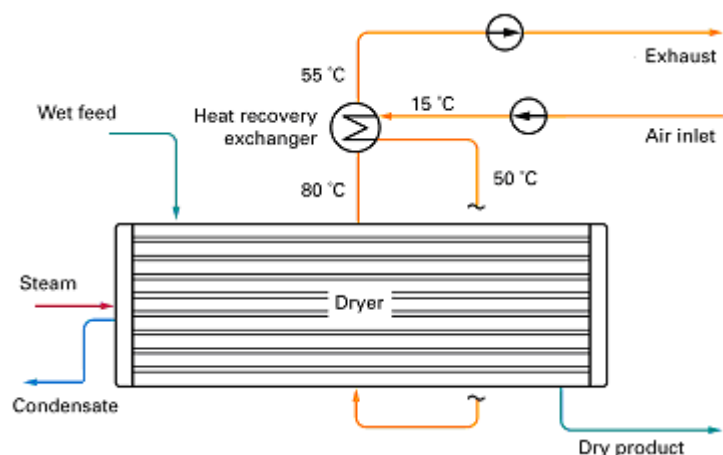


Figure 3.4: Hot Air Dryer Using Steam

Common factors resulting in excessive energy use

- Excessive drying load – for example, unnecessarily wet feed material, or off-specification product that needs to be reprocessed
- Excessive airflows
- Unnecessarily hot exhaust flow
- Hot air leaks
- Poor insulation
- Excessive fan power (for example, over specified fans restricted by dampers)
- Steam system inefficiencies

Example-4: Heat Energy in Air Drying

A food containing 80% water is to be dried at 100 °C down to moisture content of 10%. If the initial temperature of the food is 21 °C, calculate the quantity of heat energy required per unit weight of the original material, for drying under atmospheric pressure. The latent heat of vaporization of water at 100°C and at standard atmospheric pressure is 2257 kJ/kg. The specific heat capacity of the food is 3.8 kJ/kg°C and of water is 4.186 kJ/kg °C. Find also the energy requirement/kg water removed.

Calculating for 1 kg food

Initial moisture = 80%

800 g moisture is associated with 200 g dry matter.

Final moisture = 10 %,

100 g moisture is associated with 900 g dry matter,

Therefore $(100 \times 200)/900 \text{ g} = 22.2 \text{ g}$ moisture are associated with 200 g dry matter.

1 kg of original matter must lose $(800 - 22) \text{ g}$ moisture = 778 g = 0.778 kg moisture.

Heat energy required for 1 kg original material

$$\begin{aligned} &= \text{heat energy to raise temperature to } 100^{\circ}\text{C} + \text{latent heat to remove water} \\ &= (100 - 21) \times 3.8 + 0.778 \times 2257 \\ &= 300.2 + 1755.9 \\ &= 2056 \text{ kJ.} \end{aligned}$$

$$\begin{aligned} \text{Energy/kg water removed, as 2056 kJ are required to remove 0.778 kg of water,} \\ &= 2056/0.778 \\ &= 2643 \text{ kJ.} \end{aligned}$$

Steam is often used to supply heat to air or to surfaces used for drying. In condensing, steam gives up its latent heat of vaporization; in drying, the substance being dried must take up latent heat of vaporization to convert its liquid into vapour, so it might be reasoned that 1 kg of steam condensing will produce 1 kg of vapour, neglecting minor losses.

3.5. Proper Selection, Operation and Maintenance of Steam Traps

The purpose of installing the steam traps is to obtain fast heating of the product and equipment by keeping the steam lines and equipment free of condensate, air and non-condensable gases. A steam trap is a valve device that discharges condensate and air from the line or piece of equipment without discharging the steam.

Functions of Steam Traps

The three important functions of steam traps are:

- To discharge condensate as soon as it is formed
- Not to allow steam to escape.
- To be capable of discharging air and other incondensable gases.

Types of Steam Traps

The steam traps are classified as follows.

Group	Principle	Sub-group
Mechanical trap	Difference in density between steam and condensate.	Bucket type a) Open bucket b) Inverted bucket (with lever, without lever) c) Float type d) Float with lever e) Free Float
Thermodynamic trap	Difference properties in thermodynamic between steam and condensate	a) Disc type b) Orifice type
Thermostatic trap	Difference in temperature between steam and condensate	a) Bimetallic type b) Metal expansion type.

Some of the important traps in industrial use are explained as follows:

Inverted Bucket

The inverted bucket trap is a mechanically actuated model that uses an upside down bucket as a float. The bucket, connected to an outlet valve through a mechanical linkage, sinks when condensate fills the steam trap, opening the outlet valve. The bucket floats when steam enters the trap, closing the valve (Figure 3.5).

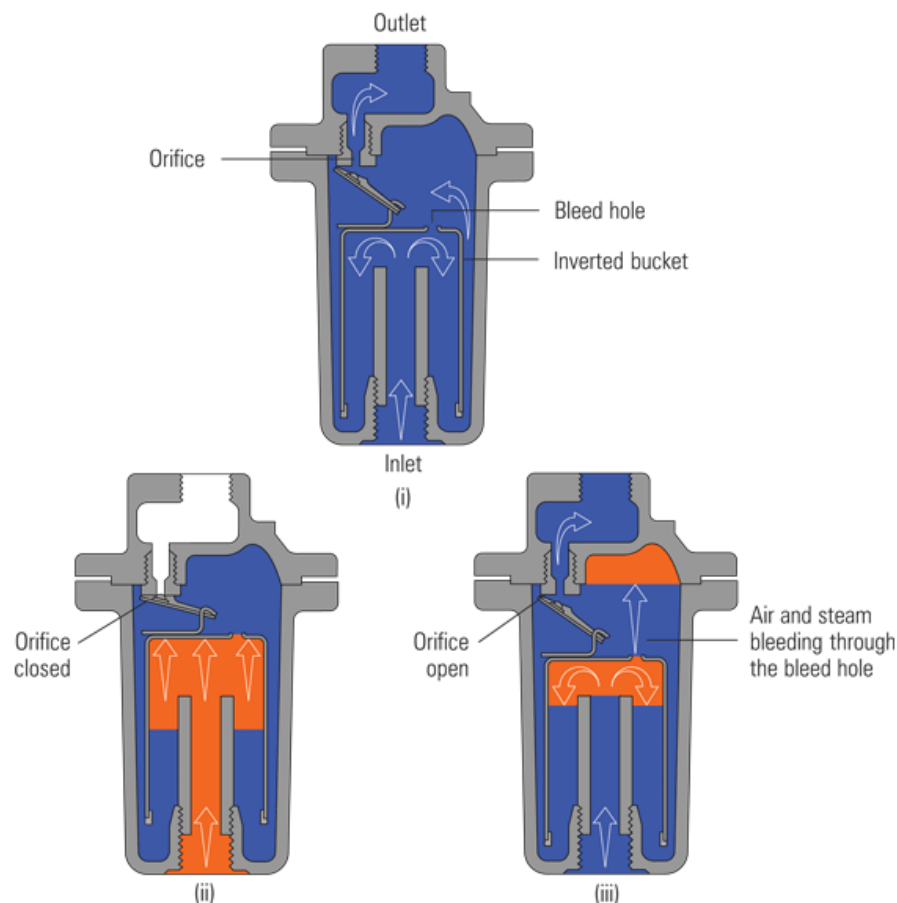


Figure 3.5: Inverted bucket trap

Inverted bucket traps, as a group, are capable of handling a wide range of steam pressures and condensate capacities. However, each specific steam trap and less a very narrow range. An inverted bucket trap designed for 8.5 Kg/cm² service operates at pressures below this; however, its capacity is so diminished that it may "back up" a system with unwanted condensate.

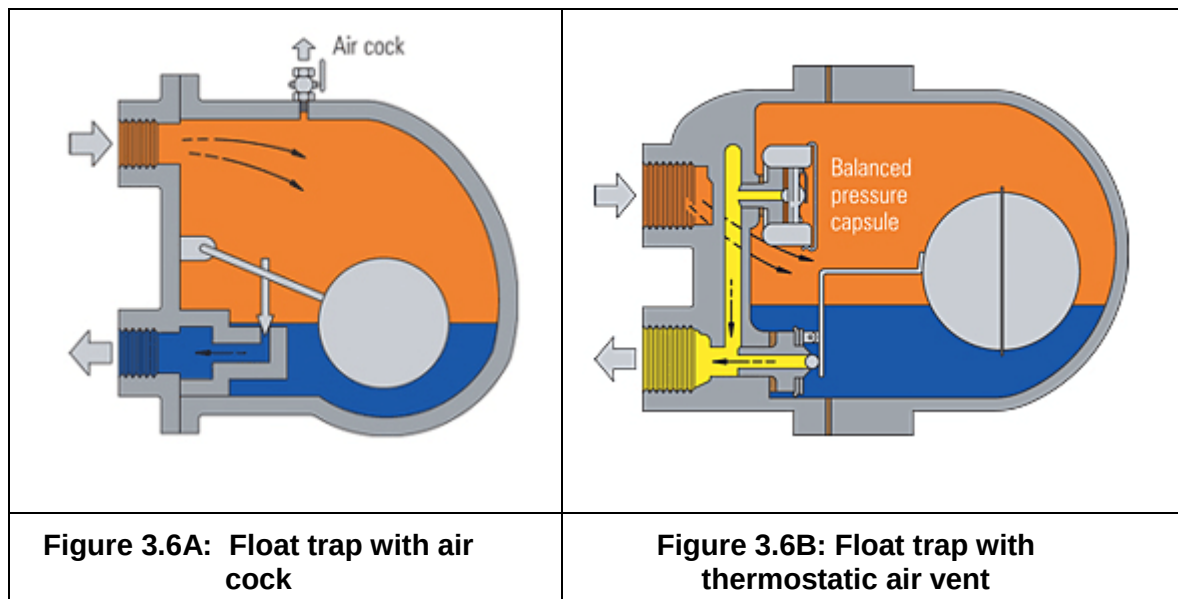
It is important to correlate the pressure rating and size with a specific application. The inverted bucket trap can be a very economical solution for low-to-medium pressures and medium capacity applications such as plant heating and light-duty processes. When handling high pressures and capacities, these traps become large, expensive, and difficult for personnel to handle.

Float and Thermostatic

The ball float type trap operates by sensing the difference in density between steam and condensate. In the case of the trap shown in Figure 3.6A, condensate reaching the trap will cause the ball float to rise, lifting the valve off its seat and releasing condensate. As can be seen, the valve is always flooded and neither steam nor air will pass through it, so early traps of this kind were vented using a manually operated cock at the top of the body. Modern traps use a thermostatic air vent, as shown in Figure 3.6B. This allows the initial air to pass whilst the trap is also handling condensate.

The automatic air vent uses the same balanced pressure capsule element as a thermostatic steam trap, and is located in the steam space above the condensate level. After releasing

the initial air, it remains closed until air or other non-condensable gases accumulate during normal running and cause it to open by reducing the temperature of the air/steam mixture. The thermostatic air vent offers the added benefit of significantly increasing condensate capacity on cold start-up.



In the past, the thermostatic air vent was a point of weakness if water hammer was present in the system. Even the ball could be damaged if the water hammer was severe. However, in modern float traps the air vent is a compact, very robust, all stainless steel capsules, and the modern welding techniques used on the ball makes the complete float-thermostatic steam trap very robust and reliable in water hammer situations.

In many ways the float-thermostatic trap is the closest to an ideal steam trap. It will discharge condensate as soon as it is formed, regardless of changes in steam pressure. Float and Thermostatic traps are an economical solution for light-to-medium condensate loads and lower pressures

Thermodynamic

The thermodynamic trap is an extremely robust steam trap with a simple mode of operation. The trap operates by means of the dynamic effect of flash steam as it passes through the trap, as depicted in Figure 3.7. The only moving part is the disc above the flat face inside the control chamber or cap.

On start-up, incoming pressure raises the disc, and cool condensate plus air is immediately discharged from the inner ring, under the disc, and out through three peripheral outlets (Figure 3.7, i).

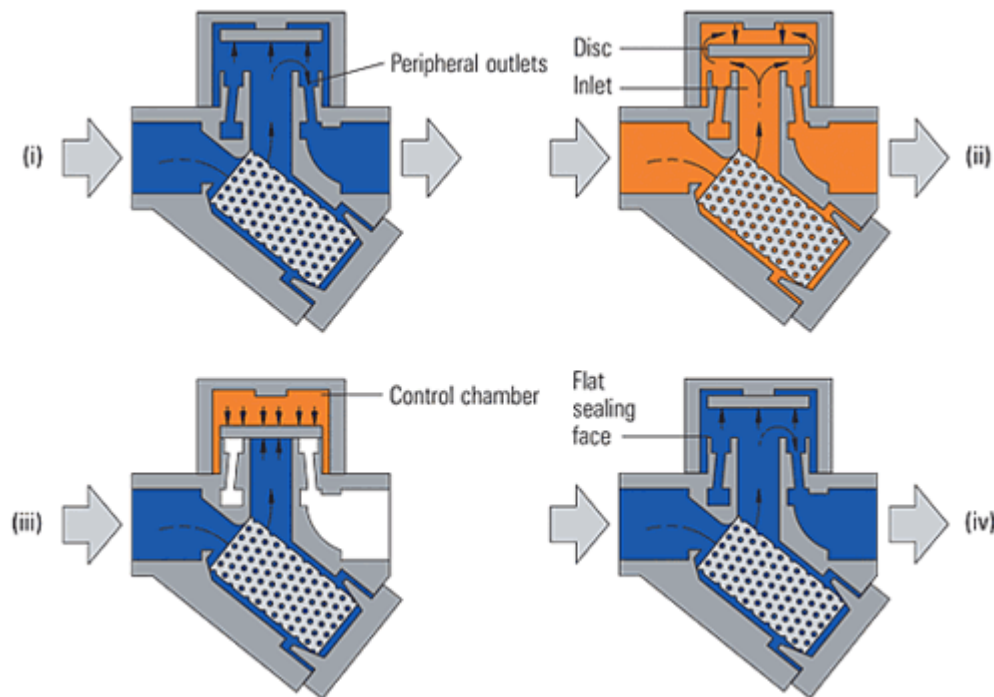


Figure 3.7: Thermodynamic Trap

Hot condensate flowing through the inlet passage into the chamber, under the disc drops in pressure and releases flash steam moving at high velocity. This high velocity creates a low pressure area under the disc, drawing it towards its seat (Figure 3.7, ii).

At the same time, the flash steam pressure builds up inside the chamber above the disc, forcing it down against the incoming condensate until it seats on the inner and outer rings. At this point, the flash steam is trapped in the upper chamber, and the pressure above the disc equals the pressure being applied to the underside of the disc from the inner ring. However, the top of the disc is subject to a greater force than the underside, as it has a greater surface area.

Eventually the trapped pressure in the upper chamber falls as the flash steam condenses. The disc is raised by the now higher condensate pressure and the cycle repeats (Figure 3.7, iv).

Thermostatic

Thermal-element thermostatic traps are temperature actuated. On startup the thermal element is in a contracted position with the valve wide-open, purging condensate, air, and other non-condensable gases. As the system warms up, heat generates pressure in the thermal element, causing it to expand and throttle the flow of hot condensate through the discharge valve.

When steam follows the hot condensate into the trap, the thermal element fully expands, closing the trap. If condensate enters the trap during system operation, it cools the element, contracting it off the seat, and quickly discharging condensate (Figure 3.8).

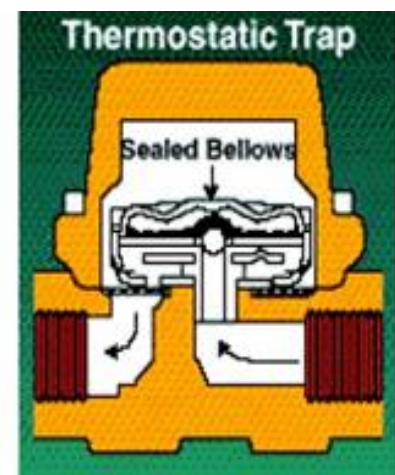


Figure 3.8: Thermostatic Trap

Thermostatic traps are small, lightweight, and compact. One trap operates over extremely broad pressure and capacity ranges. Thermal elements can be selected to operate within a range of steam temperatures. In steam tracing applications, it may be desirable to actually back up hot condensate in the lines to extract its thermal value.

Bimetallic Type

Bimetallic steam traps operate on the same principle as a heating thermostat. A bimetallic strip or wafer connected to a valve bends or distorts when subjected to a change in temperature. When properly calibrated, the valve closes off against a seat when steam is present, and opens when condensate, air, and other non-condensable gases are present (Figure 3.9).

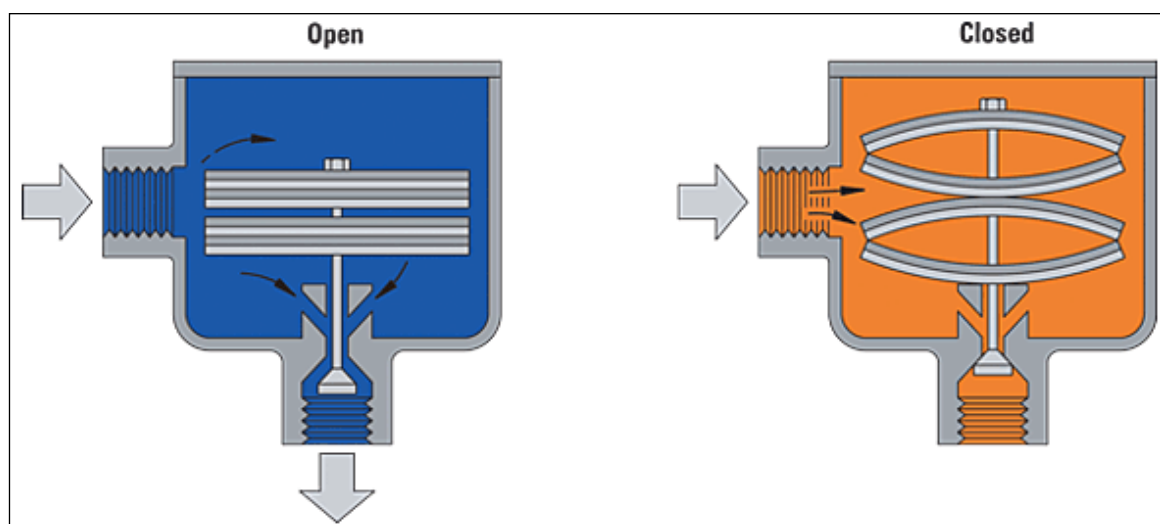


Figure 3.9: Bimetallic Trap

Advantages of the bimetallic steam trap

- Relatively small size for the condensate loads they handle
- Resistance to damage from water hammer

A disadvantage is that they must be set, generally at the plant, for a particular steam operating pressure. If the trap is used for a lower pressure, it may discharge live steam. If used at a higher steam pressure, it can back up condensate into the system.

Thermostatic traps are often considered a universal steam trap; however, they are normally not recommended for extremely high condensate requirements (over 7000 kg/hr). For light-to-moderately high condensate loads, thermostatic steam traps offer advantages in terms of initial cost, long-term energy conservation, reduced inventory, and ease in application and maintenance.

Installation of Steam Traps

In most cases, trapping problems are caused by bad installation rather than by the choice of the wrong type or faulty manufacture. To ensure a trouble-free installation, careful consideration should be given to the drain point, pipe sizing, air venting, steam locking, group trapping vs. individual trapping, dirt, water hammer, lifting of the condensate, etc.

1) Drain Point

The drain point should be so arranged that the condensate can easily flow into the trap. This is not always appreciated. For example, it is useless to provide a 15mm drain hole in the bottom of a 150 mm steam main, because most of the condensate will be carried away by the steam velocity. A proper pocket at the lowest part of the pipe line into which the condensate can drop of at least 100mm diameter is needed in such cases.

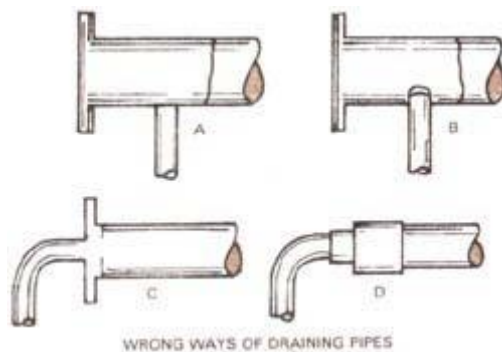


Figure 3.10 A Wrong ways of Draining Pipes

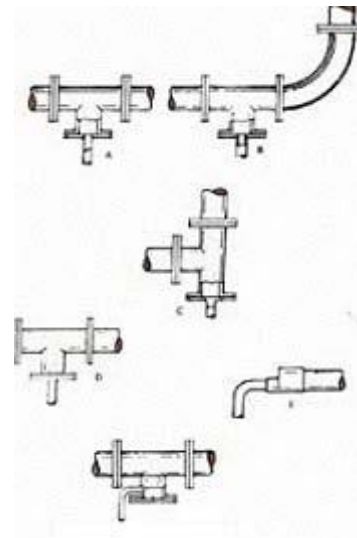


Figure 3.10 B Right ways of Draining Pipes

Figures 3.10 A and 3.10 B show the wrong and the correct practices in providing the drain points on the steam lines.

2) Pipe Sizing

The pipes leading to and from steam traps should be of adequate size. This is particularly important in the case of thermodynamic traps, because their correct operation can be disturbed by excessive resistance to flow in the condensate pipe work. Pipe fittings such as valves, bends and tees close to the trap will also set up excessive backpressures in certain circumstances.

3) Air Binding

When air is pumped into the trap space by the steam, the trap function ceases. Unless adequate provision is made for removing air either by way of the steam trap or a separate air vent, the plant may take a long time in warming up and may never give its full output.

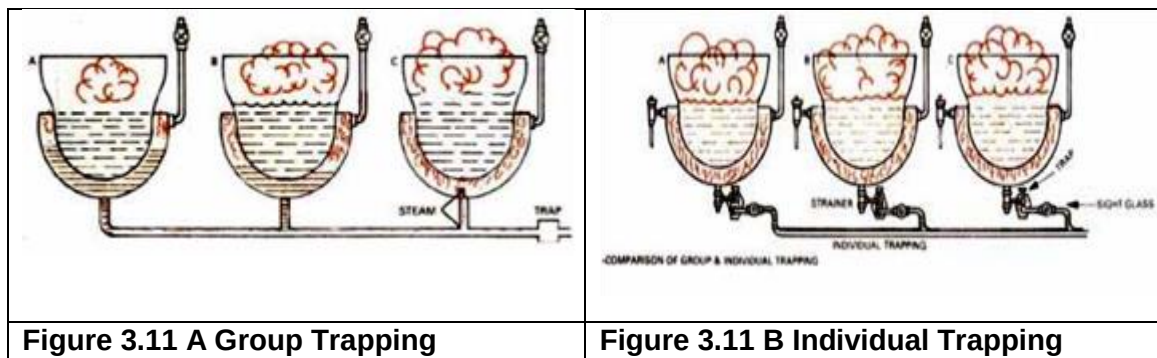
4) Steam Locking

This is similar to air binding except that the trap is locked shut by steam instead of air. The typical example is a drying cylinder. It is always advisable to use a float trap provided with a steam lock release arrangement.

5) Group Trapping vs. Individual Trapping

It is tempting to try and save money by connecting several units to a common steam trap as shown in Figure 3.11 A. This is known as group trapping. However, it is rarely successful, since it normally causes water-logging and loss of output.

The steam consumption of a number of units is never the same at a moment of time and therefore, the pressure in the various steam spaces will also be different. It follows that the pressure at the drain outlet of a heavily loaded unit will be less than in the case of one that is lightly or properly loaded. Now, if all these units are connected to a common steam trap, the condensate from the heavily loaded and therefore lower pressure steam space finds it difficult to reach the trap as against the higher pressure condensate produced by lightly or partly loaded unit. The only satisfactory arrangement, thus would be to drain each steam space with own trap and then connect the outlets of the various traps to the common condensate return main as shown in above Figure 3.11 B.



6) Dirt

Dirt is the common enemy of steam traps and the causes of many failures. New steam systems contain scale, castings, weld metal, piece of packing and jointing materials, etc. When the system has been in use for a while, the inside of the pipe work and fittings, which are exposed to corrosive condensate, can get rusted. Thus, rust in the form of a fine brown powder is also likely to be present. All this dirt will be carried through the system by the steam and condensate until it reaches the steam trap. Some of it may pass through the trap into the condensate system without doing any harm, but some dirt will eventually jam the trap mechanism. It is advisable to use a strainer positioned before the steam trap to prevent dirt from passing into the system.

7) Water Hammer

A water hammer in a steam system is caused by condensate collection in the plant or pipe work picked up by the fast moving steam and carried along with it. When this collection hits obstructions such as bends, valves, steam traps or some other pipe fittings, it is likely to cause severe damage to fittings and equipment and result in leaking pipe joints.

The problem of water hammer can be eliminated by positioning the pipes so that there is a continuous slope in the direction of flow. In case of steam mains, a slope of at least 1 m in every 100 meters is necessary, as also an adequate number of drain points every 30 to 50 meters.

8) Lifting the condensate

It is sometimes necessary to lift condensate from a steam trap to a higher level condensate return line (Figure 3.12). The condensate will rise up the lifting pipe work when the steam pressure upstream of the trap is higher than the pressure downstream of the trap.

The pressure downstream of the trap is generally called backpressure, and is made up of any pressure existing in the condensate line plus the static lift caused by condensate in the rising pipe work. The upstream pressure will vary between start-up conditions, when it is at its lowest and running conditions, when it is at its highest.

Backpressure is related to lift by using the following approximate conversion: 1 metre lift in pipe work = 1 m head static pressure or 0.1 bar backpressure. If a head of 5 m produces a backpressure of 0.5 bar, then this reduces the differential pressure available to push condensate through the trap; although under running conditions the reduction in trap capacity is likely to be significant only where low upstream pressures are used.

In steam mains at start-up, the steam pressure is likely to be very low, and it is common for water to back-up before the trap, which can lead to water hammer in the space being drained. To alleviate this problem at start-up, a liquid expansion trap, fitted as shown in Figure 3.12, will discharge any cold condensate formed at this time to waste.

As the steam main is warmed, the condensate temperature rises, causing the liquid expansion trap to close. At the same time, the steam pressure rises, forcing the hot condensate through the 'working' drain trap to the return line.

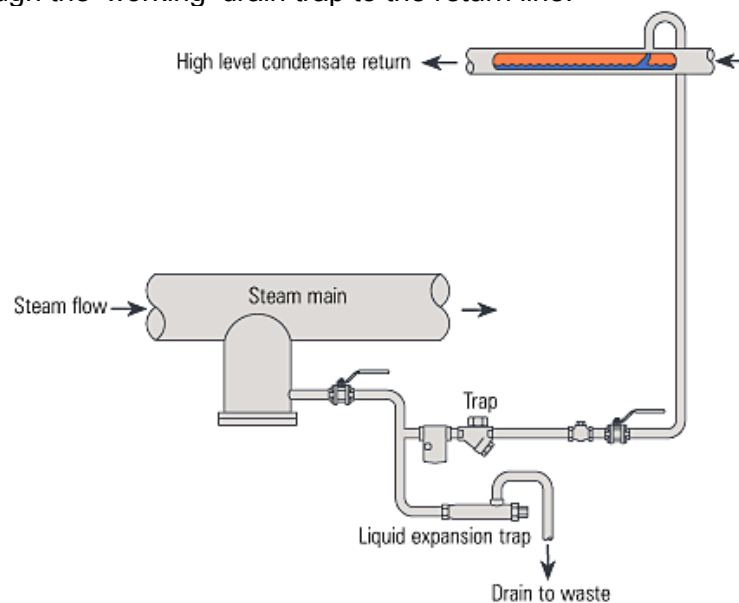


Figure 3.12 Use of a Liquid Expansion Trap

The discharge line from the trap to the overhead return line preferably discharges into the top of the main rather than simply feed to the underside, as shown in Figure 3.12. This assists operation, because although the riser is probably full of water at start-up, it sometimes contains little more than flash steam once hot condensate under pressure passes through. If the discharge line were fitted to the bottom of the return line, it would fill with condensate after each discharge and increase the tendency for water hammer and noise.

It is also recommended that a check valve be fitted after any steam trap from where condensate is lifted, preventing condensate from falling back towards the trap. The above general recommendations apply not just to traps lifting condensate from steam mains, but also to traps draining any type of process running at a constant steam pressure. Temperature controlled processes will often run with low steam pressures. Rising condensate discharge lines should be avoided at all costs, unless automatic pump-traps are used.

Maintenance of steam traps

Dirt is one of the most common causes of steam traps blowing steam. Dirt and scale are normally found in all steam pipes. Bits of jointing material are also quite common. Since steam traps are connected to the lowest parts of the system, sooner or later this foreign matter finds its way to the trap. Once some of the dirt gets logged in the valve seat, it prevents the valve from shutting down tightly thus allowing steam to escape. The valve seal should therefore be quickly cleaned, to remove this obstruction and thus prevent steam loss.

In order to ensure proper working, steam traps should be kept free of pipe-scale and dirt. The best way to prevent the scale and dirt from getting into the trap is to fit a strainer. Strainer is a detachable, perforated or meshed screen enclosed in a metal body. It should be borne in mind that the strainer collects dirt in the course of time and will therefore need periodic cleaning. It is of course, much easier to clean a strainer than to overhaul a steam trap.

At this point, we might mention the usefulness of a sight glass fitted just after a steam trap. Sight glasses are useful in ascertaining the proper functioning of traps and in detecting leaking steam traps. In particular, they are of considerable advantage when a number of steam traps are discharging into a common return line. If it is suspected that one of the traps is blowing steam, it can be quickly identified by looking through the sight glass.

In most industries, maintenance of steam traps is not a routine job and is neglected unless it leads to some definite trouble in the plant. In view of their importance as steam savers and to monitor plant efficiency, the steam traps require considerably more care than is given.

One may consider a periodic maintenance schedule to repair and replace defective traps in the shortest possible time, preferable during regular maintenance shut downs in preference to break down repairs.

Guide to Steam Trap Selection

Actual energy efficiency can be achieved only when

- a) Selection
- b) Installation and
- c) Maintenance of steam traps meet the requirements for the purpose it is installed

The following Table 3.2 gives installation of suitable traps for different process applications.

Table 3.2: Selection of Steam trap

Application	Feature	Suitable trap
Steam mains	- Open to atmosphere, small capacity - Frequent change in pressure - Low pressure - high pressure	Thermodynamic type
Equipment - Reboiler - Heater - Dryer - Heat exchanger etc.	- Large capacity - Variation in pressure and temperature is undesirable - Efficiency of the equipment is a problem	Mechanical trap, Bucket, Inverted bucket, float
- Tracer line - Instrumentation	Reliability with no over heating	Thermodynamic & Bimetallic

3.6. Performance Assessment Methods for Steam Traps

Steam trap performance assessment is basically concerned with answering the following two questions:

- Is the trap working correctly or not?
- If not, has the trap failed in the open or closed position?

Traps that fail 'open' result in a loss of steam and its energy. Where condensate is not returned, the water is lost as well. The result is significant economic loss, directly via increased boiler plant costs, and potentially indirectly, via decreased steam heating capacity.

Traps that fail 'closed' do not result in energy or water losses, but can result in significantly reduced heating capacity and/or damage to steam heating equipment.

Visual Testing

Visual testing includes traps with open discharge sight glasses (Figure 3.13), sight checks, test tees and three way test valves. In every case, the flow or variation of flow is visually observed. This method works well with traps that cycle on/off, or dribbles on light load. On high flow or process, due to the volume of water and flash steam, this method becomes less viable. If condensate can be diverted ahead of the trap or a secondary flow can be turned off, the load on the trap will drop to zero or a very minimal amount so the visual test will allow in determining the leakage.

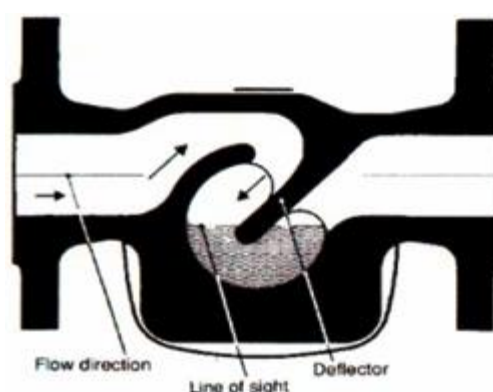


Figure 3.13: Sight Glass

Sound Testing

Sound testing includes ultrasonic leak detectors (Figure 3.14), mechanics stethoscopes, screwdriver or metal rod with a human ear against it. All these use the sound created by flow to determine the trap function like the visual method. This method works best with traps that cycle on/off or dribbles on light load. Traps which have modulating type discharge patterns are hard to check on high flows. (Examples are processes, heat exchangers, air handling coils, etc.). Again by diverting condensate flow ahead of the trap or shutting off a secondary flow as mentioned under visual testing, the noise level will drop to zero or a very low level if the trap is operating correctly. If the trap continues to flow heavily after diversion it would be leaking or blowing through.



Figure 3.14: Ultrasonic Testing

Temperature Testing

Temperature testing includes infrared guns (Figure 3.15), surface pyrometers, temperature tapes, and temperature crayons. Typically they are used to gauge the discharge temperature on the outlet side of the trap. In the case of temperature tapes or crayon, they are set for a predetermined temperature and they indicate when temperature exceeds that level. Infrared guns and surface pyrometer can detect temperatures on both sides of the trap. Both the infrared and surface pyrometers require bare pipe and a clean surface to achieve a reasonable reading. The temperature reading will typically be lower than actual internal pipe temperature due to the fact that steel does have some heat flow resistance. Scale on the inside of the pipe can also affect the heat transfer. Some of the more expensive infrared guns can compensate for wall thickness and material differences. Blocked or turned off traps can easily be detected by infrared guns and surface pyrometers, as they will show low or cold temperatures. They could also pick up traps which may be undersized or backing up large amounts of condensate by detecting low temperature readings.



Figure 3.15: Infra Red Testing

3.7. Energy Saving Opportunities

1. Monitoring Steam Traps

For testing a steam trap, there should be an isolating valve provided in the downstream of the trap and a test valve shall be provided in the trap discharge. When the test valve is opened, the following points have to be observed:

Condensate discharge-Inverted bucket and thermodynamic disc traps should have intermittent condensate discharge. Float and thermostatic traps should have a continuous condensate discharge. Thermostatic traps can have either continuous or intermittent discharge depending upon the load. If inverted bucket traps are used for extremely small load, it will have a continuous condensate discharge.

Flash steam-This shall not be mistaken for a steam leak through the trap. The users sometimes get confused between a flash steam and leaking steam. The flash steam and the leaking steam can be approximately identified as follows:

- If steam blows out continuously in a blue stream, it is a leaking steam.
- If a steam floats out intermittently in a whitish cloud, it is a flash steam.

2. Continuous steam blow and no flow indicate there is a problem in the trap.

Whenever a trap fails to operate and the reasons are not readily apparent, the discharge from the trap should be observed. A step-by-step analysis has to be carried out mainly with reference to lack of discharge from the trap, steam loss, continuous flow, sluggish heating, to find out whether it is a system problem or the mechanical problem in the steam trap.

3. Avoiding Steam Leakages

Steam leakage is a visible indicator of waste and must be avoided. It has been estimated that a 3 mm diameter hole on a pipeline carrying 7kg/cm² steam would waste 33 KL of fuel oil per year. Steam leaks on high-pressure mains are prohibitively costlier than on low pressure mains. Any steam leakage must be quickly attended to. In fact, the plant should consider a regular surveillance programme for identifying leaks at pipelines, valves, flanges and joints. Indeed, by plugging all leakages, one may be surprised at the extent of fuel savings, which may reach up to 5% of the steam consumption in a small or medium scale industry or even higher in installations having several process departments.

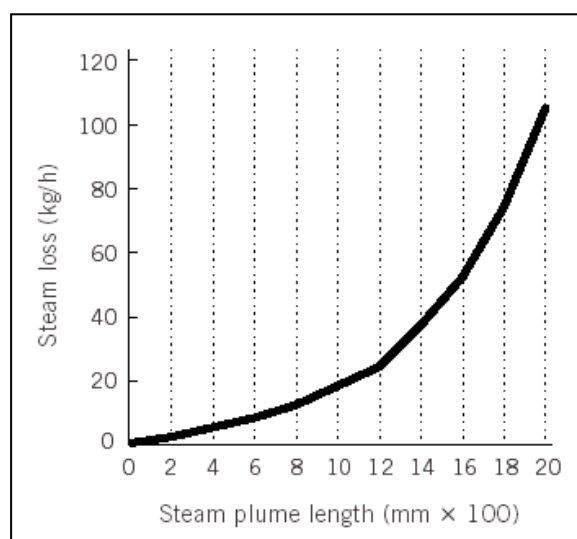


Figure 3.16: Steam Loss vs Plume Length

To avoid leaks it may be worthwhile considering replacement of the flanged joints which are rarely opened in old plants by welded joints. Figure 3.16 provides a quick estimate for steam leakage based on plume length.

Example

- Plume Length = 700 mm
- Steam loss = 10 kg/h

The following Table 3.3 highlights the significance of loss through steam leaks.

Table: 3.3 Steam Losses due to Leakage

S.No.	Dia. of Leak (in mm)	Annual Steam Loss (Tons/year)	
		At 3.5 kg/cm ²	At 7.0 kg/cm ²
1	1.5	29.1	47.3
2	3.0	116.4	192.7
3	4.5	232.7	432.7
4	6.0	465.4	767.3

4. Providing Dry Steam for Process

The best steam for industrial process heating is the dry saturated steam. Wet steam reduces total heat in the steam. Also water forms a wet film on heat transfer and overloads traps and condensate equipment. Super-heated steam is not desirable for process heating because it gives up heat at a rate slower than the condensation heat transfer of saturated steam.

It must be remembered that a boiler without a super heater cannot deliver perfectly dry saturated steam. At best, it can deliver only 95% dry steam. The dryness fraction of steam depends on various factors, such as the level of water, improper boiler water treatment etc. As steam flows through the pipelines, it undergoes progressive condensation due to the loss of heat to the colder surroundings; the extent of the condensation depends on the effectiveness of the lagging. For example, with poor lagging, the steam can become excessively wet.

Since dry saturated steam is required for process equipment, due attention must be paid to the boiler operation and lagging of the pipelines. The steam produced in a boiler designed to generate saturated steam is inherently wet. Although the dryness fraction will vary according to the type of boiler, most shell type steam boilers will produce steam with a dryness fraction of between 95 and 98%.

Wet steam can reduce plant productivity and product quality, and can cause damage to most items of plant and equipment. The water content of the steam produced by the boiler is further increased if priming and carryover occur.

A steam separator (Figure 3.17) may be installed on the steam main as well as on the branch lines to reduce wetness in steam and improve the quality of the steam going to the units. By change of direction of steam, steam separators causes the entrained water particles to be separated out and delivered to a point where they can be drained away as condensate through a conventional steam trap.

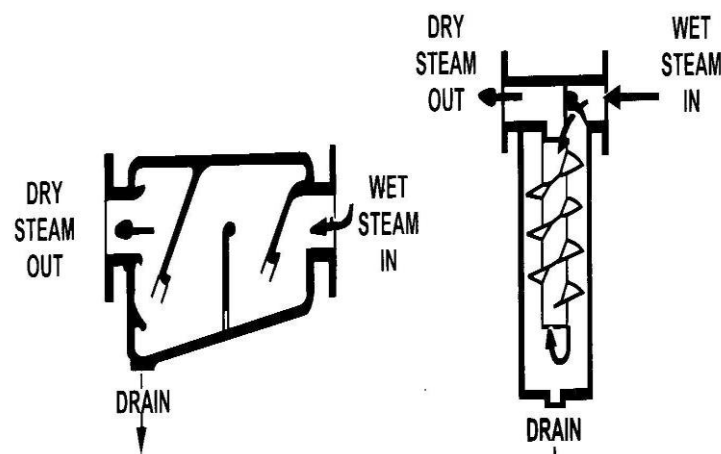


Figure 3.17: Steam Separators

5. Utilising Steam at the Lowest Acceptable Pressure for the Process

A study of the steam tables would indicate that the latent heat in steam reduces as the steam pressure increases. It is only the latent heat of steam, which takes part in the heating process when applied to an indirect heating system. Thus, it is important that its value be kept as high as possible. This can only be achieved if we go in for lower steam pressures.

As a guide, the steam should always be generated and distributed at the highest possible pressure, but utilized at a low pressure as possible since it has higher latent heat.

However, it may also be seen from the steam tables that the lower the steam pressure, the lower will be its temperature. Since temperature is the driving force for the transfer of heat at lower steam pressures, the rate of heat transfer will be slower and the processing time greater. In equipment where fixed losses are high (e.g. big drying cylinders), there may even be an increase in steam consumption at lower pressures due to increased processing time. There are however, several equipment in certain industries where one can profitably go in for lower pressures and realize economy in steam consumption without materially affecting production time.

Therefore, there is a limit to the reduction of steam pressure. Depending on the equipment design, the lowest possible steam pressure with which the equipment can work should be selected without sacrificing either on production time or on steam consumption.

6. Proper Utilization of Directly Injected Steam

The heating of a liquid by direct injection of steam is often desirable. The equipment required is relatively simple, cheap and easy to maintain. No condensate recovery system is necessary. The heating is quick, and the sensible heat of the steam is also used up along with the latent heat, making the process thermally efficient. In processes where dilution is not a problem, heating is done by blowing steam into the liquid (i.e.) direct steam injection is applied. If the dilution of the tank contents and agitation are not acceptable in the process (i.e.) direct steam agitation are not acceptable, indirect steam heating is the only answer.

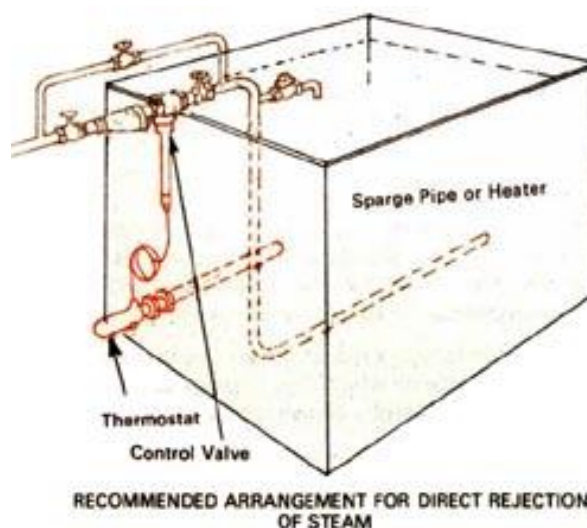


Figure 3.18: Temperature Control for Directly Injected Steam

Ideally, the injected steam should be condensed completely as the bubbles rise through the liquid. This is possible only if the inlet steam pressures are kept very low - around 0.5 kg/cm^2 - and certainly not exceeding 1 kg/cm^2 . If pressures are high, the velocity of the steam bubbles will also be high and they will not get sufficient time to condense before they reach the surface. Figure 3.18 shows a recommended arrangement for direct injection of steam.

A large number of small diameter holes (2 to 5mm), facing downwards, should be drilled on the separate pipe. This will help in dissipating the velocity of bubbles in the liquid. A thermostatic control of steam admitted is highly desirable.

7. Minimising Heat Transfer Barriers

The metal wall may not be the only barrier in a heat transfer process. There is likely to be a film of air, condensate and scale on the steam side. On the product side, there may also be baked-on product or scale, and a stagnant film of product.

Agitation of the product may eliminate the effect of the stagnant film, whilst regular cleaning on the product side should reduce the scale.

Regular cleaning of the surface on the steam side may also increase the rate of heat transfer by reducing the thickness of any layer of scale; however, this may not always be possible. This layer may also be reduced by careful attention to the correct operation of the boiler, and the removal of water droplets carrying impurities from the boiler.

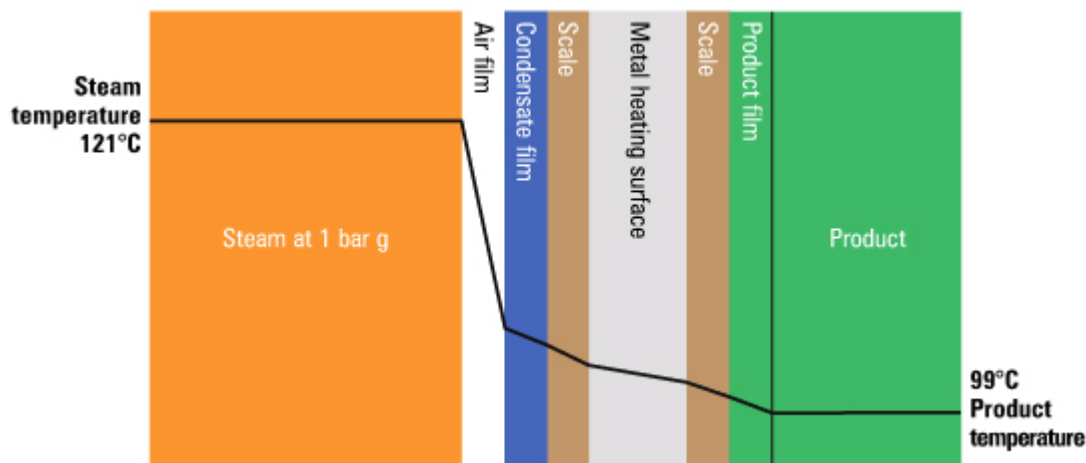


Figure 3.19: Heat Transfer Barriers

The elimination of the condensate film is not quite as simple. As the steam condenses to give up its enthalpy of evaporation, droplets of water may form on the heat transfer surface. These may merge together to form a continuous film of condensate. The condensate film may be between 100 and 150 times more resistant to heat transfer than a steel heating surface, and 500 to 600 times more resistant than copper.

As air is a good insulator, it provides even more resistance to heat transfer. Air may be between 1500 and 3000 times more resistant to heat flow than steel, and 8000 to 16000 more resistant than copper. This means that a film of air only 0.025 mm thick may resist as much heat transfer as a wall of copper 400 mm thick. These comparative relationships depend on the temperature profiles across each layer.

Figure 3.19 illustrates the effect this combination of layers has on the heat transfer process. These barriers to heat transfer not only increase the thickness of the entire conductive layer, but also greatly reduce the mean thermal conductivity of the layer.

The more resistant the layer to heat flow, the larger the temperature gradient is likely to be.

This means that to achieve the same desired product temperature, the steam pressure may need to be significantly higher.

To achieve the desired product output and minimise the cost of process steam operations, a high heating performance may be maintained by reducing the thickness of the films on the condensing surface and removal of air from the supply steam.

8. Proper Air Venting

When steam is first admitted to a pipe after a period of shutdown, the pipe is full of air. Further, amounts of air and other non-condensable gases will enter with the steam, although the proportions of these gases are normally very small compared with the steam. When the steam condenses, these gases will accumulate in pipes and heat exchangers. Precautions should be taken to discharge them. The consequence of not removing air is a lengthy warming up period, reduction in plant efficiency and process performance. Air in the steam system will also affect the system temperature. Air will exert its own pressure within the system, which will add to the pressure of the steam to give a total pressure.

A layer of air only 1 mm thick can offer the same resistance to heat as a layer of water 25 μm thick, a layer of iron 2 mm thick or a layer of copper 15 mm thick. It is very important therefore to remove air from any steam system.

Automatic air vents for steam systems (which operate on the same principle as thermostatic steam traps) should be fitted above the condensate level so that only air or steam-air mixtures can reach them. The best location for them is at the end of the steam mains. In addition to air venting at the end of a main, air vents should also be fitted in parallel with an inverted bucket trap or a thermodynamic trap.

9. Condensate Recovery

The steam condenses after giving off its latent heat in the heating coil or the jacket of the process equipment. A sizable portion (about 25%) of the total heat in the steam leaves the process equipment as hot water. If this water is returned to the boiler house, it will reduce the fuel requirements of the boiler. For every 6 $^{\circ}\text{C}$ rise in the feed water temperature, there will be approximately 1% saving of fuel in the boiler. However, in most cases, the boiler water has to be chemically treated to prevent or reduce scale formation, whereas the condensate is almost entirely pure water which needs no treatment. With a good percentage of the condensate returning to the boiler house, the expenses involved for water treatment will be reduced by an appreciable amount.

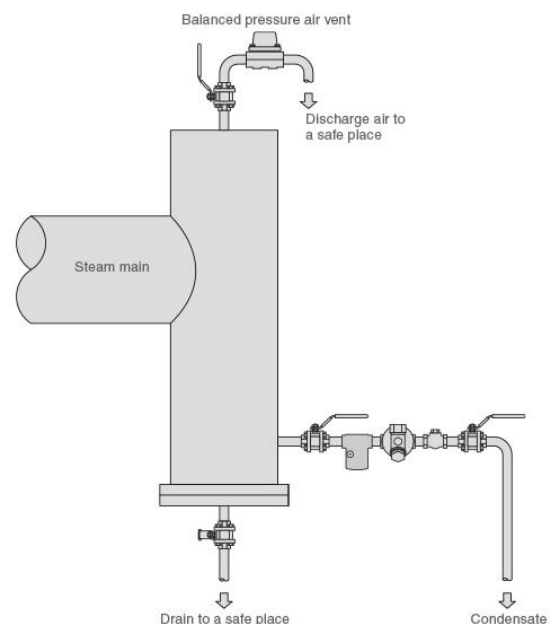


Figure 3.20: Air Vent

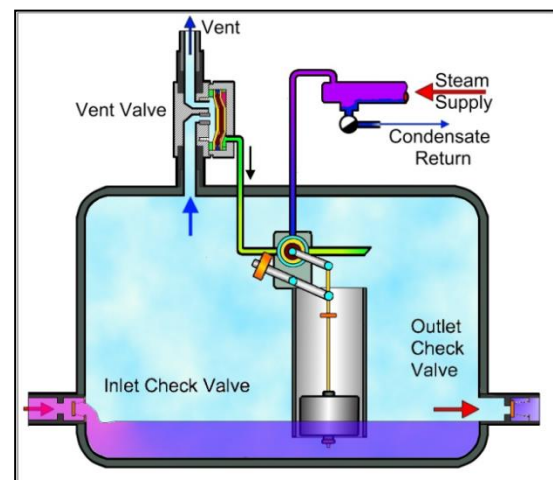


Figure 3.21: Pressure Powered Pump

Use a Steam Driven Pump: A pressure powered pump (Figure 3.21) uses steam pressure to push the condensate from the receiver back to the boiler house. In principle it consists of a receiver which receives condensate from different process/equipment. Once the condensate reaches a set level, the steam valve is opened and the steam pressure pushes the condensate to the boiler room. The operation is cyclic in nature. The advantage is pumping of condensate without losing much heat in the form of flash steam without any cavitation problems.

10. Insulation of Steam Pipelines and Hot Process Equipment

Steam lines including flanges and valves should be insulated to prevent heat loss. The recommended thickness of insulation will mainly depend on surface temperature desired after insulation. The energy and cost savings will depend on the size of the pipe (diameter and length of run), the temperature of steam and the surroundings, heat transfer co-efficient and the number of hours of operation of the plant.

The following Table 3.4 indicates the effect of insulating bare pipes

Table 3.4: Effect of Insulation on Steam Pipes

Pipe Size, inch	Economic Insulation Thickness, mm	Radiation Losses* (kW/m)	
		Insulated	Uninsulated
1/2	15	125	692
2	25	243	1820
4	40	298	2942
12	50	588	7614

* Comparison of Radiation Losses (Pipe Surface Temperature at 150 °C)

Heat can be lost due to radiation from steam pipes. As an example while lagging steam pipes, it is common to see leaving flanges uncovered. An uncovered flange is equivalent to leaving 0.6 metre of pipe line unlagged. If a 0.15 m steam pipe diameter has 5 uncovered flanges, there would be a loss of heat equivalent to wasting 5 tons of coal or 3000 litres of oil a year. This is usually done to facilitate checking the condition of flange but at the cost of considerable heat loss. The remedy is to provide easily detachable insulation covers, which can be easily removed when necessary. The various insulating materials used are cork, Glass wool, Rock wool and Asbestos.

Effect of insulation of flanges: 12 Flanges of 150 mm diameter.

Heat loss in the following 2 cases:

Case (I) – Bare flanges

Case (II) – Flanges with 50 mm insulation and aluminum cladding

Parameter	Unit	Case (I)	Case (II)
Heat Loss	kcal/year	36,300	4,100
Steam Loss	kg/Year	68	3.2
Fuel Loss	kg/Year	55	0.26
Energy Saving Potential	Rs. Per Year	60	2.8

11. Flash Steam Recovery

Flash steam is produced when condensate at a high pressure is released to a lower pressure and can be used for low pressure heating.

The higher the steam pressure and lower the flash steam pressure the greater the quantity of flash steam that can be generated. In many cases, flash steam from high pressure equipment is made use of directly on the low pressure equipment to reduce use of steam through pressure reducing valves.

The flash steam quantity can be calculated by the following formula with the help of a steam table:

$$\text{Flash steam available \%} = \frac{S_1 - S_2}{L_2}$$

Where,

S_1 is the sensible heat of higher pressure condensate.

S_2 is the sensible heat of the steam at lower pressure (at which it has been flashed).

L_2 is the latent heat of flash steam (at lower pressure).

Example-5: Calculating the amount of flash steam from condensate

Hot condensate at 7 bar g has a heat content of about 721 kJ/kg. When it is released to atmospheric pressure (0 bar g), each kilogram of water can only retain about 419 kJ of heat. The excess energy in each kilogram of the condensate is therefore $721 - 419 = 302$ kJ. This excess energy is available to evaporate some of the condensate into steam, the amount evaporated being determined by the proportion of excess heat to the amount of heat required to evaporate water at the lower pressure, which in this example, is the enthalpy of evaporation at atmospheric pressure, 2258 kJ/kg.

$$\text{Therefore, in this example, the percentage of flash steam evaporated} = \frac{302}{2258} \times 100\%$$

$$\text{Flash steam evaporated} = 13.4\%$$

The amount of flash steam in the pipe is the most important factor when sizing trap discharge lines.

Flash steam can be used on low pressure applications like direct injection and can replace an equal quantity of live steam that would be otherwise required. The demand for flash steam should exceed its supply, so that there is no buildup of pressure in the flash vessel and the consequent loss of steam through the safety valve. Generally, the simplest method of using flash steam is to flash from a machine/equipment at a higher pressure to a machine/equipment at a lower pressure, thereby augmenting steam supply to the low pressure equipment.

In general, a flash system should run at the lowest possible pressure so that the maximum amount of flash is available and the backpressure on the high pressure systems is kept as low as possible.

Flash steam from the condensate can be separated in an equipment called the 'flash vessel'. This is a vertical vessel as shown in the Figure 3.22. The diameter of the vessel is such that a considerable drop in velocity allows the condensate to fall to the bottom of the vessel from where it is drained out by a steam trap preferably a float trap. Flash steam itself rises to leave the vessel at the top. The height of the vessel should be sufficient enough to avoid water being carried over in the flash steam.

The condensate from the traps (A) along with some flash steam generated passes through vessel (B). The flash steam is let out through (C) and the residual condensate from (B) goes out through the steam trap (D). The flash vessel is usually fitted with a 'pressure gauge' to know the quality of flash steam leaving the vessel. A 'safety valve' is also provided to vent out the steam in case of high pressure build up in the vessel.

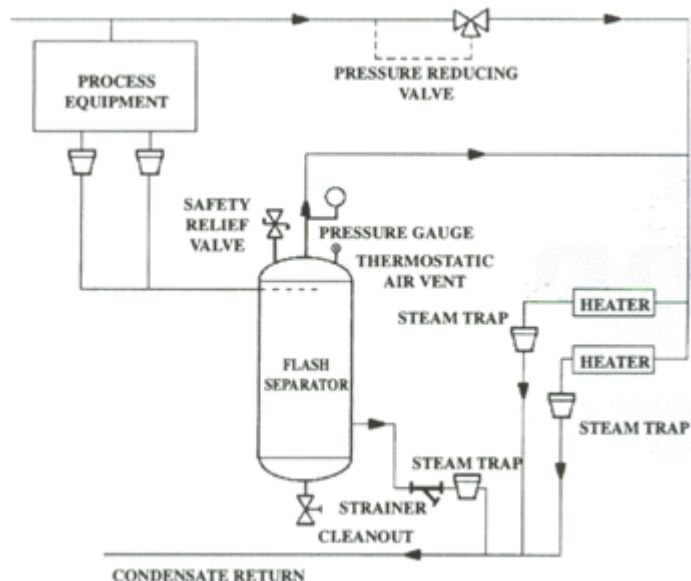


Figure 3.22: Flash Steam Recovery

12. Pipe Redundancy

All redundant (piping which are no longer needed) pipelines must be eliminated, which could be, at times, up to 10-15 % of total length. This would reduce steam distribution losses significantly. The pipe routing shall be made for transmission of steam in the shortest possible way, so as to reduce the pressure drop in the system, thus saving the energy. However, care should be taken that, the pipe routing shall be flexible enough to take thermal expansion and to keep the terminal point loads, within the allowable limit.

13. Reducing the Work to be done by Steam

The equipment should be supplied with steam as dry as possible. The plant should be made efficient. For example, if any product is to be dried such as in a laundry, a press could be used to squeeze as much water as possible before being heated up in a dryer using steam.

When the steam reaches the place where its heat is required, it must be ensured that the steam has no more work to do than is absolutely necessary. Air-heater batteries, for example, which provide hot air for drying, will use the same amount of steam whether the plant is fully or partly loaded. So, if the plant is running only at 50 per cent load, it is wasting twice as much steam (or twice as much fuel) than necessary.

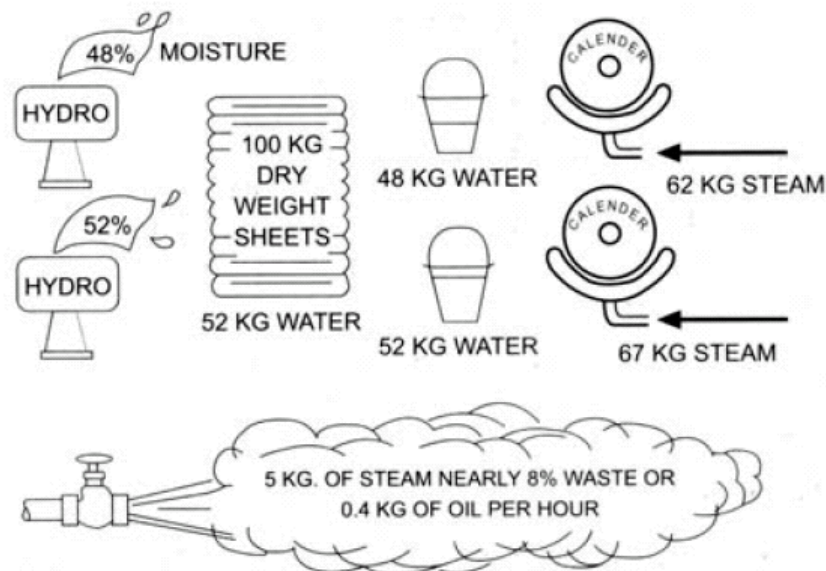


Figure 3.23 Steam Wastage Due to Insufficient Mechanical Drying

The energy saving is affected by following measures:

- Reduction in operating hours
- Reduction in steam quantity required per hour
- Use of more efficient technology
- Minimizing wastage.

Always use the most economical way to removing the bulk of water from the wet material. Steam can then be used to complete the process. For this reason, hydro-extractors, spin dryers, squeeze or calendar rolls, presses, etc. are initially used in many drying processes to remove the mass of water. The efficiency with which this operation is carried out is most important. For example, in a laundry for finishing sheets (100 kg/hr dry weight), the normal moisture content of the sheets as they leave the hydro extractor is 48% by weight.

Thus, the steam heated iron has to evaporate nearly 48 kg of water. This requires 62 kg of steam. If, due to inefficient drying in the hydro-extractor, the steam arrive at the iron with 52% moisture content i.e. 52 kg of water has to be evaporated, requiring about 67 kg of steam. So, for the same quantity of finished product, the steam consumption increases by 8 per cent. This is illustrated in Figure 3.23.

Examples

Problem-6:

In a crude distillation unit of a refinery, 50 MetricTonne/hr of crude is heated using saturated steam in a heat exchanger from 35°C to 85°C. Plant is operating for 8000 hrs/annum. Consider specific heat of the crude as 0.631 kCal/kg°C. The plant has two steam headers operating at 3 bar and 8 bar respectively, passing nearby the heat exchanger. Cost of steam is same for both 3 bar and 8 bar @ Rs.4.50/kg.

As an Energy Manager, which of the following options will you recommend to the unit based on the annual cost of steam?

- Utilising 3 bar steam
- Utilising 8 bar steam

Given: Data from steam table:

Steam Pressure, bar	Enthalpy kCal/kg		
	Water	Evaporation	Steam
3.0	133	517	650
8.0	171	489	660

Ans:

Heat gain in crude = $m \times C_p \times \Delta T$

Heat gain in crude = $50 \times 1000 \times 0.631 \times (85 - 35)$

Heat gain in crude = 1577500 kCal/hr

Heat gain in crude = heat loss in steam

Heat loss in steam = mass of the steam $\times$ latent heat of steam

Option A:

3 bar pressure steam having 517 kCal/kg of latent heat

Mass of the steam = $1577500 / 517$

Mass of the steam = 3051 kg / hr

Cost of steam expenditure = $3051 \times 8000 \times 4.5$

Cost of steam expenditure = 10.98 Cr

Option B:

8 bar pressure steam having 489 Kcal/kg of latent heat

Mass of the steam = $1577500 / 489$

Mass of the steam = 3225 kg / hr

Cost of steam expenditure = $3226 \times 8000 \times 4.5$

Cost of steam expenditure = 11.61 Cr

Recommendation: Option A is recommended as it is found to be economical (Steam @ 3 bar pressure) since the expenditure per annum is less when compared to Option B.

Problem-7:

In a process plant, 20 TPH of steam after pressure reduction with pressure reducing valve to 20 kg/cm² gets superheated. The temperature of steam is 280°C. The management wants to install a de-super heater to convert superheated steam into saturated steam at 20 kg/cm² for process use, and its saturation temperature is 210°C.

Calculate quantity of water at 30°C to be injected in de-super heater to get the desired saturated steam using the following data.

Specific heat of superheated steam = 0.45 kCal/Kg°C

Latent heat of steam at 20 kg/cm² = 450 kCal/kg

Ans:

Quantity of heat available above saturation = $20,000 \times 0.45 \times (280-210)$
= 6,30,000kCal

Quantity of water required in desuperheater = $Q \times \{1 \times (210-30) + 450\} = 630000$
= 1000 kg/hr

4. INDUSTRIAL FURNACES

A furnace is an equipment to melt metals for casting or heat materials for change of shape (rolling, forging etc.) or change of properties (heat treatment).

4.1. Types and Classification of Different Furnaces

Based on the method of generating heat, furnaces are broadly classified into two types namely combustion type (using fuels) and electric type. The combustion type furnace can be broadly classified as oil fired, coal fired or gas fired.

Based on the mode of charging of material furnaces can be classified as (i) Intermittent or Batch type furnace or Periodical furnace and (ii) Continuous furnace.

Based on mode of waste heat recovery as recuperative and regenerative furnaces.

Another type of furnace classification is made based on mode of heat transfer, mode of charging and mode of heat recovery as shown in the figure 4.1 below.

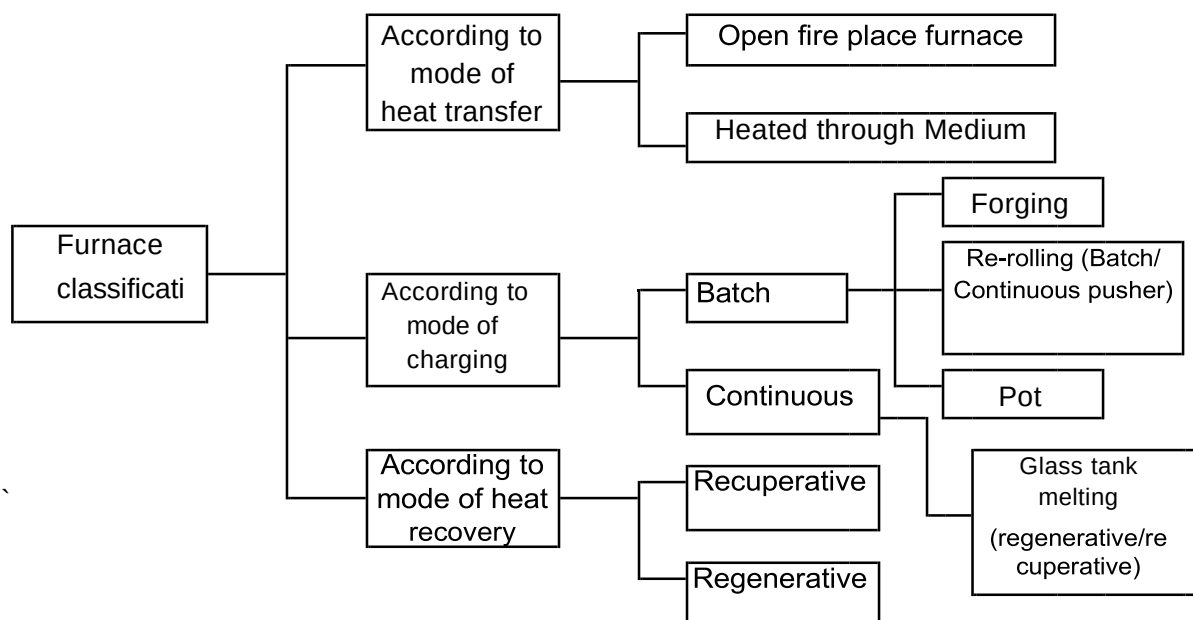


Figure 4.1: Furnace Classification

The electric furnaces can be broadly classified as resistance type for heating and induction and arc furnace for melting of metals.

Characteristics of an Efficient Furnace

Furnace should be designed so that in a given time, as much of material as possible can be heated to a uniform temperature as possible with the least possible fuel and labour. To achieve this end, the following parameters can be considered.

- Determination of the quantity of heat to be imparted to the material or charge.
- Liberation of sufficient heat within the furnace to heat the stock and overcome all heat losses.
- Transfer of available part of that heat from the furnace gases to the surface of the heating stock.

- Equalisation of the temperature within the stock.
- Reduction of heat losses from the furnace to the minimum possible extent.

Furnace Energy Supply

Since the products of flue gases directly contact the stock, type of fuel chosen is of importance. For example, some materials will not tolerate sulphur in the fuel. Also use of solid fuels will generate particulate matter, which will interfere the stock placed inside the furnace. Hence, vast majority of the furnaces use liquid fuel, gaseous fuel or electricity as energy input. Electricity is used in induction and arc furnaces for melting steel and castiron. Non-ferrous melting utilizes oil as fuel.

Oil Fired Furnace

Furnace oil is the major fuel used in oil fired furnaces, especially for reheating and heat treatment of materials. LDO is used in furnaces where presence of sulphur is undesirable. The key to efficient furnace operation lies in complete combustion of fuel with minimum excess air.

Furnaces operate with efficiencies as low as 7% as against upto 90% achievable in other combustion equipment such as boiler. This is because of the high temperature at which the furnaces have to operate to meet the required demand. For example, a furnace heating the stock to 1200°C will have its exhaust gases leaving at least at 1200°C resulting in a huge heat loss through the stack. However, improvements in efficiencies have been brought about by methods such as preheating of stock, preheating of combustion air and other waste heat recovery systems.

4.2. Performance Evaluation of a Fuel Fired Furnace

The fuel required for combustion is cleaned, preheated and burnt in the combustion zone of the furnace. Thermal efficiency of the furnaces is the ratio of heat delivered to a material stock and heat supplied to the heating equipment. The purpose of a heating process is to introduce a certain amount of thermal energy into a material stock / product, raising it to a certain temperature to prepare it for additional processing or change its properties.

This results in energy losses in different areas and forms as shown in san key diagram (Figure 4.2). The major losses that occur in the fuel fired furnaces are listed below.

1. Heat lost through exhaust gases either as sensible heat or as incomplete combustion
2. Heat loss through furnace walls and hearth
3. Heat loss to the surroundings by radiation and convection from the outer surface of the walls
4. Heat loss through gases leaking through cracks, openings and doors.

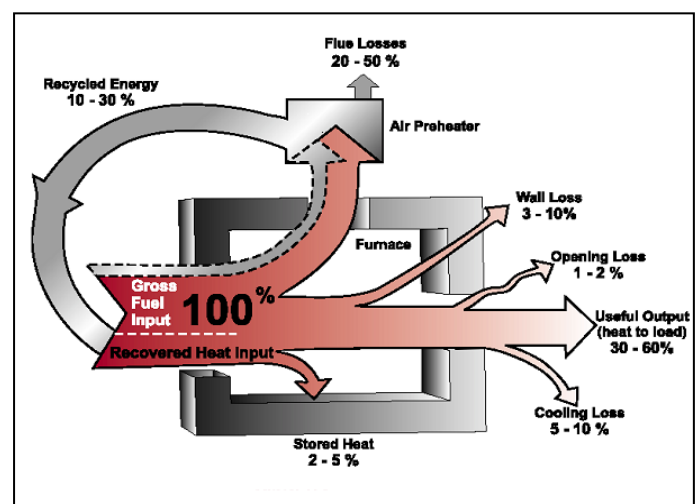


Figure 4.2 Fuel Fired Furnace

Economy in fuel can be achieved if the total heat that can be passed on to the stock is as large as possible.

Furnace Efficiency

Thermal efficiency of a furnace is determined either by direct or indirect method of evaluation.

Direct method

The efficiency of furnace can be assessed by measuring the amount of heat added to the stock and the heat in the fuel consumed, on a batch/day basis as relevant.

$$\text{Thermal efficiency of the furnace} = \frac{\text{Heat in the stock}}{\text{Heat in the fuel consumed for heating the stock}} \times 100$$

The quantity of heat to be imparted (Q_s) to the stock can be found from the following relation;

$$Q_s = m \times C_p \times (t_1 - t_2)$$

where,

Q_f	=	Quantity of heat imparted to the stock in kCal
m	=	Weight of the stock in kg
C_p	=	Mean specific heat of stock in kCal/kg°C
t_1	=	Final temperature of stock desired, °C
t_2	=	Initial temperature of the stock before it enters the furnace, °C

$$\text{Heat in fuel} = \text{Quantity of fuel (q) in kg/h} \times \text{GCV in kCal/kg}$$

Example -1:

The following are the operating parameters of rerolling mill furnace

Weight of input material	- 10 T/hr
Furnace oil consumption	- 600 litres/hr
Specific gravity of oil	- 0.92
Final material temperature	- 1200 °C
Initial material temperature	- 40 °C
Outlet flue gas temperature	- 650 °C
Specific heat of the material	- 0.12 kcal/kg/°C
GCV of oil	- 10,000 kCal/kg
Percentage yield	- 92 %

- Calculate furnace efficiency by direct method
- Calculate Specific fuel consumption on finished product basis

Solution:

a) Furnace efficiency by direct method

Heat input	$600 \text{ lit/hr} \times 0.92 \times 10000 = 55,20,000 \text{ kcal/hr}$
Heat output	$10,000 \times 0.12 \times (1200 - 40) = 1,39,2000 \text{ kcal/hr}$
Efficiency	$1,39,2000 / 55,20,000 = 25.2 \%$

b) Specific fuel consumption on finished product basis

Weight of finished products	$10 \times 0.92 = 9.2 \text{ T/hr}$
Furnace oil consumption	600 litres/hr
Specific fuel consumption	$600/9.2 = 65.2 \text{ litres/ton}$

Indirect Method

Similar to the method of evaluating boiler efficiency by indirect method, furnace efficiency can also be calculated by indirect methods. Furnace efficiency is calculated after subtracting sensible heat loss in flue gas, loss due to moisture in flue gas, heat loss due to openings in furnace, heat loss through furnace skin and other unaccounted losses.

In order to find out furnace efficiency using indirect method, various parameters that are required are hourly furnace oil consumption, material output, excess air quantity, temperature of flue gas, temperature of furnace at various zones, skin temperature and hot combustion air temperature. Instruments like infrared thermometer, fuel consumption monitor, surface thermocouple and other measuring devices are required to measure the above parameters.

Typical thermal efficiencies for common industrial furnaces are given in Table 4.1.

Table 4.1: Thermal efficiencies for common industrial furnaces

Furnace Type	Typical thermal efficiency (%)
1) Low Temperature furnaces	
a. 540 – 980 °C (Batch type)	20-30
b. 540 – 980 °C (Continuous type)	15-25
c. Coil Anneal (Bell) radiant type	4-7
d. Strip Anneal Muffle	7-12
2) High temperature furnaces	
a. Slot forge	5-12
b. Pusher, Roll down or Rotary	7-14
c. Batch forge	5-10
d. Car Bottom	7-12
3) Continuous Kiln	
a. Hoffman	25-93
b. Tunnel	21-82
c. Transverse-arch Annular	26-96

4) Ovens	
a. Indirect fired ovens (20°C-370°C)	35-40
b. Direct fired ovens (20°C-370°C)	35-40

Energy Balance in a Typical Reheating Furnace

The heat inputs and outputs are calculated (as per JIS GO702) on the basis of per tonne of stock or product output and simplified.

Example-2: Furnace Efficiency Calculation (Indirect Method)

An oil-fired reheating furnace has an operating temperature of around 1340°C. Average fuel consumption is 400 litres/hour. The flue gas exit temperature after air pre heater is 650 °C. Air is preheated from ambient temperature of 40°C to 190°C through an air pre-heater. The furnace has 460 mm thick wall (x) on the billet extraction outlet side, which is 1 m high (D) and 1 m wide. Evaluate the heat balance to identify heat losses, efficiency and specific fuel consumption. The other data are as follows.

Specific gravity of oil	=	0.92
Average fuel oil consumption	=	400 Litres / hr
	=	400 x 0.92 = 368 kg/hr
Theoretical air	=	14.12 kg air /kg oil
O ₂ in flue gas	=	12%
CO ₂ in flue gas	=	6.5%
CO in flue gas	=	50 ppm
Weight of stock/billet	=	6000 kg/hr
Abs. humidity	=	0.03437 kg/kg dry air
Preheated oil temperature	=	100 °C
Specific heat of oil	=	0.5 kcal/kg°C
Specific heat of billet	=	0.12 kcal/kg°C
Specific heat of flue gas in kcal/kg °C	=	0.26 kcal/kg °C
C _p of super-heated vapour	=	0.47 kcal/kg °C
Surface temperature of ceiling	=	85 °C
Surface temperature of side walls	=	100 °C
Surface temperature of flue duct	=	64 °C
Area of ceiling	=	15 m ²
Area of side walls	=	36 m ²
Area of flue duct	=	10.3 m ²
Diameter of flue duct	=	0.4 m

Furnace oil constituents (% by weight)

Carbon - 85.9 %, Hydrogen -12%, Oxygen - 0.7%, Nitrogen - 0.5%, Sulphur - 0.5%, Moisture - 0.35%, Ash - 0.05%, GCV- 10,000 kcal/kg

Solution:

1) Calculation of air quantity and specific fuel consumption:

% Excess Air supplied	=	$\frac{O_2 \%}{21 - O_2 \%} \times 100$ [from flue gas analysis]
	=	$12 / (21 - 12)$
	=	133.3 %
Total mass of air supplied/ kg of fuel (AAS)	=	{1 + EA/100} x theoretical air
	=	{1 + (133.3/100)} X 14.12
	=	32.94 kg of air / kg of fuel
Amount of dry flue gas (m)	=	Amount of wet flue gas – Amount of water vapour in flue gas
	=	(AAS + 1 kg of fuel) – (Moisture + 9 Hydrogen)
	=	(32.94 + 1) – [(0.35/100) + 9 x (12/100)]
	=	33.94 – 1.084
	=	32.86 kg dry flue gas /kg of fuel
Specific fuel consumption (F)	=	Amount of fuel consumed (kg/hr) / Amount of billet (t/hr)
	=	368 / 6
	=	61.33 kg of fuel / tonne of billet

2) Calculation of Heat Input:

Combustion heat of fuel (Q_1)	=	Amount of fuel consumed per tonne of billet X GCV of fuel
	=	61.3 X 10,000
	=	6,13,300 kcal/tonne of billet
Sensible heat of fuel (Q_2)	=	$F \times C_{p \text{ fuel}} [t_f - t_a]$
	=	61.33 x 0.5 x (100 – 40)
	=	1840 kcal/tonne of billet
Total heat input	=	$Q_1 + Q_2$
	=	6,13,300 + 1840
	=	6,15,140 kcal/tonne of billet

3) Calculation of Heat Output:

Heat carried away by 1 tonne of billet (Q_3)	=	$1000 \text{ kg/t} \times C_p \times (T_o - T_i)$
	=	$1000 \times 0.12 \times (1340 - 40)$
	=	1,56,000 kcal/tonne of billet
Heat loss in dry flue gas	=	$F \times m \times C_{pfg} [t_1 - t_a]$

per tonne of billet (Q_4)		
	=	$61.33 \times 32.86 \times 0.26 \times [650 - 40]$
	=	3,19,627 kcal/tonne of billet
Heat loss due to formation of water vapour from fuel per tonne of billet (Q_5)	=	$F \times M \times \{584 + C_{p \text{ of super heated vapour }} \times [t_1 - t_a]\}$
	=	$61.33 \times 1.084 \times \{584 + 0.47 \times (650 - 40)\}$
	=	57,886 kcal/tonne of billet
Heat loss due to moisture in combustion air (Q_6)	=	$F \times AAS \times \text{Humidity of air} \times C_{p \text{ of super heated vapour }} \times [t_1 - t_a]$
	=	$61.33 \times 32.94 \times 0.03437 \times 0.47 \times (650 - 40)$
	=	19,907 kcal/tonne of billet
% Heat loss due to partial conversion of C to CO (Q_7)	=	$F \times \frac{\%CO \times C}{\%CO + \%CO_2} \times 5654$
	=	$61.33 \times \frac{0.005 \times 0.859}{0.005 + 6.5} \times 5654$
	=	229 kcal/tonne of billet
Amount of heat loss from the furnace body and other sections (Q_8)	=	$(q_1 + q_2 + q_3 + q_4)$, kcal/hr / Amount of billet (t/hr)
where,		
q_1 , Heat loss from the furnace body ceiling surface (horizontal surface facing upward)	=	$\{h \times \Delta t^{1.25} \times A_i\} + \{4.88 \times \epsilon \times [(T_w/100)^4 - (T_a/100)^4] \times A_i\}$
where,		
H	=	Natural convection heat transfer rate 2.8 (kcal/m ² h °C)
Δt	=	$T_w - T_a = 358 - 313 = 45$
E	=	Emissivity of the furnace body surface (0.75)
q_1	=	$\{2.8 \times 45^{1.25} \times 15\} + \{4.88 \times 0.75 \times [(358/100)^4 - (313/100)^4] \times 15\}$
	=	8644 kcal/hr
q_2 , Heat loss from the furnace body sidewall surfaces (vertical surfacing sideways)	=	$\{h \times \Delta t^{1.25} \times A_i\} + \{4.88 \times \epsilon \times [(T_w/100)^4 - (T_a/100)^4] \times A_i\}$
where,		
H	=	Natural convection heat transfer rate 2.2 (kcal/m ² h °C)
Δt	=	$T_w - T_a = 373 - 313 = 60$
q_2	=	$\{2.2 \times 60^{1.25} \times 36\} + \{4.88 \times 0.75 \times [(373/100)^4 - (313/100)^4] \times 36\}$

	=	26084 kcal/hr
q_3 , Bottom (horizontal surface facing downward)	=	As the bottom surface is not exposed to the atmosphere, q_3 is ignored in this calculation
q_4 , Heat loss from the flue gas duct between the furnace exit and the air preheater (including heat loss from the external surface of the air preheater)	=	$\{h \times \Delta t^{1.25} / D^{0.25} \times A_i\} + \{4.88 \times \epsilon \times [(T_w/100)^4 - (T_a/100)^4] \times A_i\}$
where,		
H	=	Natural convection heat transfer rate 1.1 (kcal/m ² h °C)
Δt	=	$T_w - T_a = 337 - 313 = 24$ °K
E	=	Emissivity of the furnace body surface (0.75)
q_4	=	$[1.1 \times 24^{1.25} / 0.4^{0.25} \times 10.3] + \{4.88 \times 0.75 \times [(337/100)^4 - (313/100)^4] \times 10.3\}$
	=	2001 kcal/hr
Q_8	=	$(q_1 + q_2 + q_3 + q_4)$, kcal/hr / Amount of billet (t/hr)
	=	$(8644 + 26084 + 0 + 2001)/6$
	=	6,122 kcal/t
Radiation heat loss through furnace openings (Q_9)	=	$hr \times A \times \phi \times 4.88 [(T_i/100)^4 - (T_o/100)^4]$ / Amount of billet
Where,		
Hr	=	Open time during the period of heat balancing
A	=	Area of an opening in m ² = 1 m ²
ϕ (from graph)	=	Co-efficient based on the profile of furnace openings
	=	Diameter (or) the shortest side / wall thickness = 1 / 0.46 = 2.17
	=	0.70 (value corresponding to 2.17 and square shape from graph (Figure 4.3))
Q_9	=	$1 \times 1 \times 0.70 \times 4.88 \times [(1613/100)^4 - (313/100)^4] / 6$
	=	38,485 kcal/t
Other unaccounted heat losses (Q_{10})	=	Other heat loss will include the following, - Heat carried away by cooling water in the flue damper - Heat carried away by cooling water at the furnace access door - Radiation from the furnace bottom - Heat accumulated by refractory - Instrumental error and measuring error & Others
Q_{10} (unaccounted losses)	=	$(Q_1 + Q_2) - (Q_3 + Q_4 + Q_5 + Q_6 + Q_7 + Q_8 + Q_9)$
	=	$(6,15,140) - (1,56,000 + 3,19,627 + 57886 + 19,907 + 229 + 6,122 + 38,485)$
	=	16,884 kcal/t

Total heat output	=	$Q_3 + Q_4 + Q_5 + Q_6 + Q_7 + Q_8 + Q_9 + Q_{10}$
		$1,56,000 + 3,19,627 + 57,886 + 19,907 + 229 + 6,122 + 38,485 + 16,884$
	=	6,15,140 kcal/t

4) Heat balance table

Heat Input			Heat output		
Item	kcal/t	%	Item	kcal/t	%
Combustion heat of fuel (Q_1)	6,13,300	99.70	Heat carried away by 1 tonne of billet (Q_3)	1,56,000	25.4
Sensible heat of fuel (Q_2)	1,840	0.30	Heat loss in dry flue gas per tonne of billet (Q_4)	3,19,627	52.0
			Heat loss due to formation of water vapour from fuel per tonne of billet (Q_5)	57,886	9.4
			Heat loss due to moisture in combustion air (Q_6)	19,907	3.2
			% Heat loss due to partial conversion of C to CO (Q_7)	229	0.04
			Amount of heat loss from the furnace body and other sections (Q_8)	6,122	1.0
			Radiation heat loss through furnace openings (Q_9)	38,485	6.26
			Unaccounted losses (Q_{10})	16,884	2.7
Total	6,15,140	100		6,15,140	100

5. Efficiency of furnace (by direct method)

$$\eta_{\text{furnace}} = \frac{\text{Heat carried away by billet, kCal/hr}}{\text{Combustion heat of fuel, kCal/hr}} \times 100$$

$$= \frac{[(6000 \text{ kg/hr} \times 0.12 \text{ kCal/kg } ^\circ\text{C} \times (1340 - 40) ^\circ\text{C}]}{368 \text{ kg/hr} \times 10000 \text{ kCal/kg}} \times 100$$

$$= 25.4\%$$

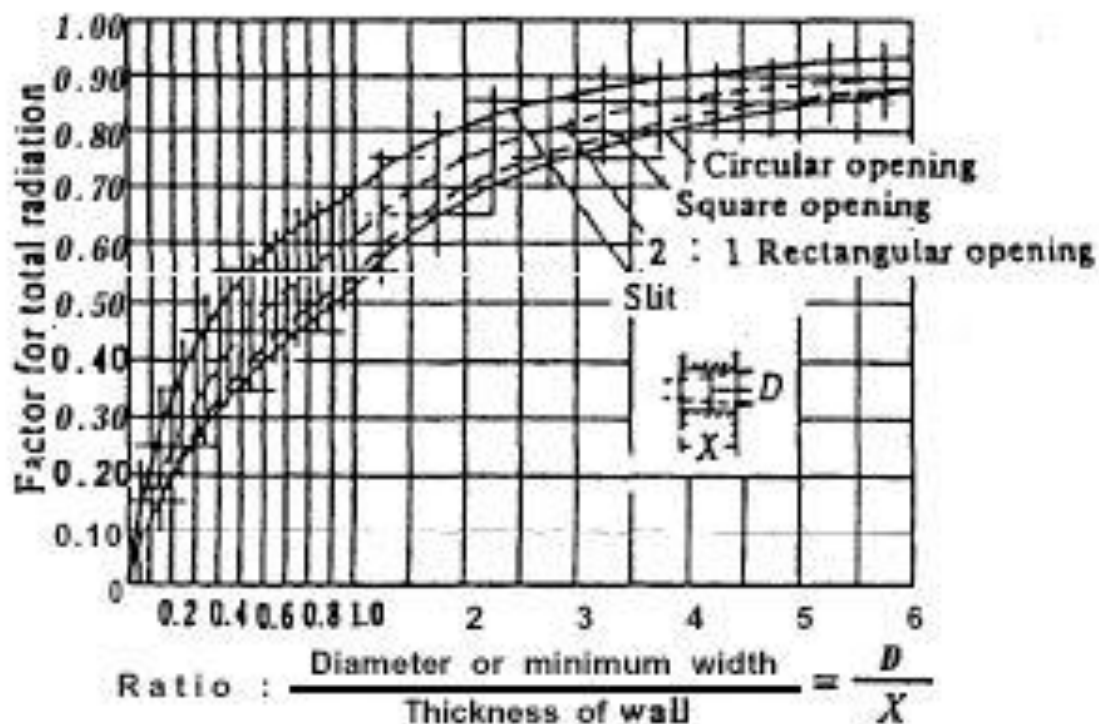


Figure 4.3: Factor for determining the equivalent of heat release from openings to the quality of heat release from perfect black body

The instruments required for carrying out performance evaluation in a furnace is given in the Table 4.2.

Table 4.2 Furnace Instrumentation

Sl. No.	Measuring Parameters	Location of Measurement	Instrument Required	Required Value
1.	Furnace soaking zone temperature (reheating furnaces)	Soaking zone side wall	Pt/Pt-Rh thermocouple with indicator and recorder	1200-1300°C
2.	Flue gas	Flue gas exit from furnace and entry to recuperator	Chromel Alummel Thermocouple with indicator	700°C max.
3.	Flue gas	After recuperator	Hg in steel thermometer	300°C (max)
4.	Furnace hearth pressure in the heating zone	Near charging end side wall over hearth level	Low pressure ring gauge	+0.1 mm of Wg
5.	Flue gas analyser	Near charging end side wall	Fuel efficiency monitor for oxygen & temperature.	O ₂ % = 5 t = 700°C (max)
6.	Billet temperature	Portable	Infrared Pyrometer or optical pyrometer	----

4.3. General Fuel Economy Measures in Furnaces

Typical energy efficiency measures for an industry with furnace are:

- 1) Complete combustion with minimum excess air
- 2) Correct heat distribution
- 3) Operating at the desired temperature
- 4) Reducing heat losses from furnace openings
- 5) Maintaining correct amount of furnace draught
- 6) Optimum capacity utilization
- 7) Waste heat recovery from the fluegases
- 8) Minimum refractory losses
- 9) Use of Ceramic Coatings

1. Complete Combustion with Minimum Excess Air:

The amount of heat lost in the flue gases (stack losses) depends upon amount of excess air. In the case of a furnace carrying away flue gases at 900°C, % heat lost is shown in table 4.3.

Table 4.3: Heat Loss in Flue Gas Based on Excess Air Level

Excess Air	% of total heat in the fuel carried away by waste gases (flue gas temp. 900 °C)
25	48
50	55
75	63
100	71

To obtain complete combustion of fuel with the minimum amount of air, it is necessary to control air infiltration, maintain pressure of combustion air, fuel quality and excess air monitoring.

Higher excess air will reduce flame temperature, furnace temperature and heating rate. On the other hand, if the excess air is less, then unburnt components in flue gases will increase and would be carried away in the flue gases through stack. The figure 4.4 also indicates relation between air ratio and exhaust gas loss.

The optimization of combustion air is the most attractive and economical measure for energy conservation. The impact of this measure is higher when the temperature of furnace is high. Air ratio is the value that is given by dividing the actual air amount by the theoretical combustion air amount, and it represents the extent of excess of air.

If a reheating furnace is not equipped with an automatic air/fuel ratio controller, it is necessary to periodically sample gas in the furnace and measure its oxygen contents by a gas analyzer. The Figure 4.5 shows a typical example of a reheating furnace equipped with an automatic air/fuel ratio controller.

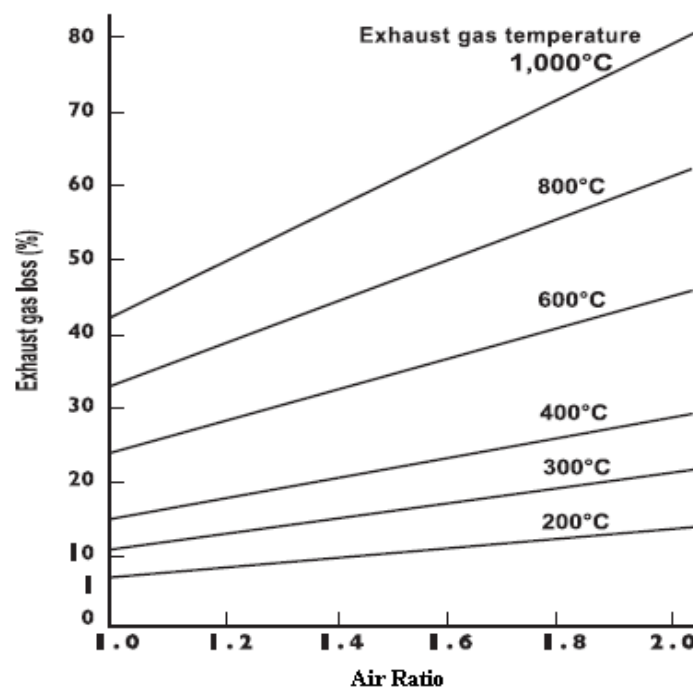


Figure 4.4: Relation between air ratio and exhaust gas

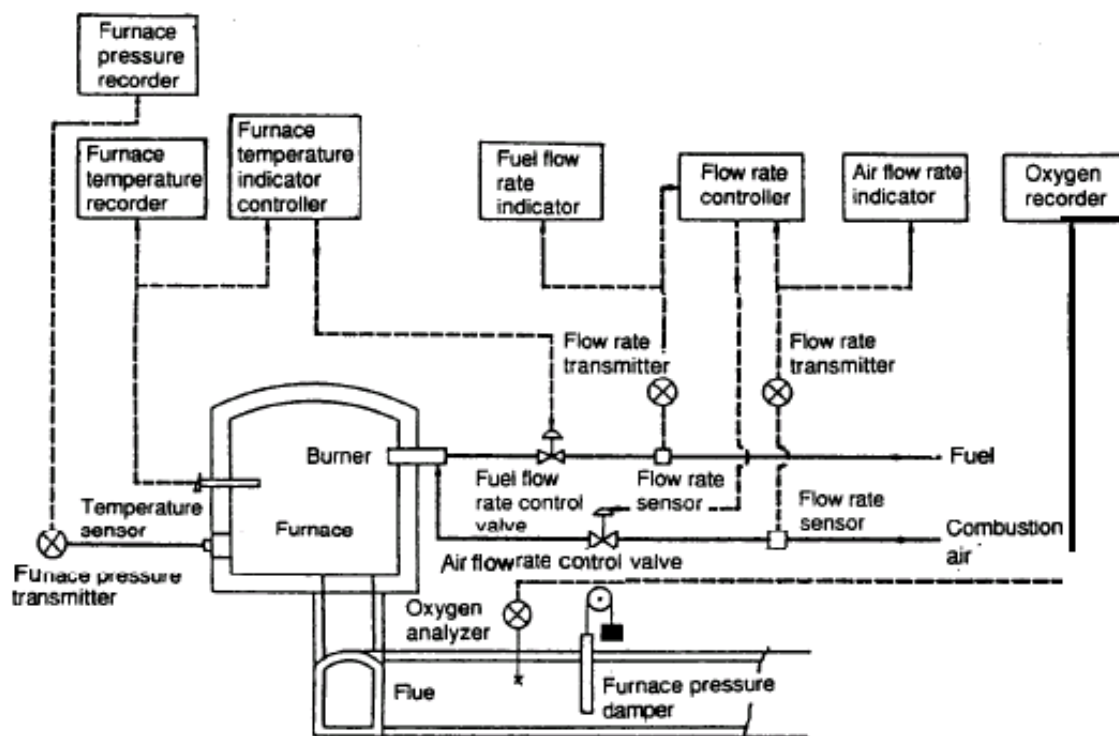


Figure 4.5: Air/fuel ratio control system with flow rate controller

More excess air also means more scale losses, which is equally a big loss in terms of money.

2. Proper Heat Distribution:

Furnace design should be such that in a given time, as much of the stock could be heated uniformly to a desired temperature with minimum fuel firing rate.

Following care should be taken when using burners, for proper heat distribution:

- i) The flame should not touch any solid object and should propagate clear of any solid object. Any obstruction will de atomise the fuel particles thus affecting combustion and create black smoke. If flame impinges on the stock, there would be increase in scale losses (Refer Figures 4.6 and 4.7).
- ii) If the flames impinge on refractories, the incomplete combustion products can settle and react with the refractory constituents at high flame temperatures.
- iii) The flames of different burners in the furnace should stay clear of each other. If they intersect, inefficient combustion would occur. It is desirable to stagger the burners on the opposite sides.
- iv) The burner flame has a tendency to travel freely in the combustion space just above the material. In small furnaces, the axis of the burner is never placed parallel to the hearth but always at an upward angle. Flame should not hit the roof.

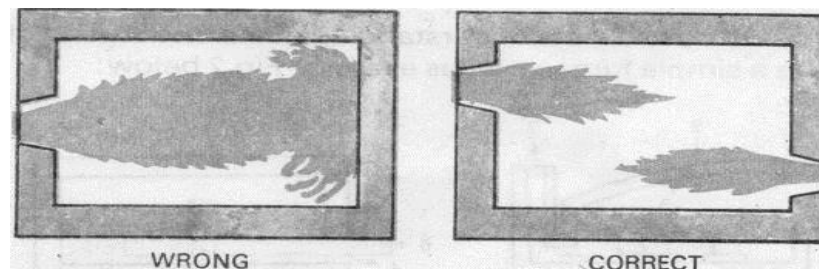


Figure 4.6: Heat Distribution in Furnace

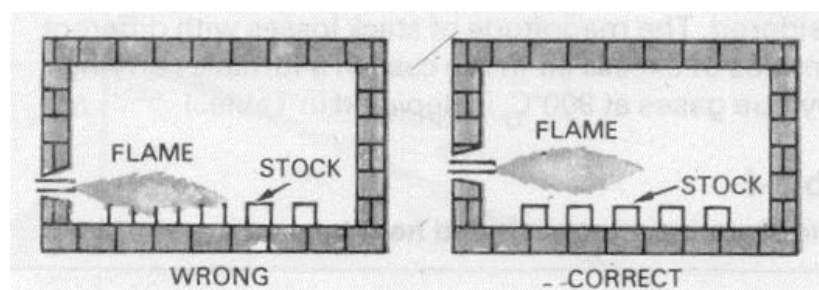


Figure 4.7: Alignment of Burners in Furnace

- v) The larger burners produce a long flame, which may be difficult to contain within the furnace walls. More burners of less capacity give better heat distribution in the furnace and also increase furnace life.
- vi) For small furnaces, it is desirable to have a long flame with golden yellow colour while firing furnace oil for uniform heating. The flame should not be too long that it enters the chimney or comes out through the furnace top or through doors. In such cases, major portion of additional fuel is carried away from the furnace.

3. Maintaining Optimum Operating Temperature of Furnace:

It is important to operate the furnace at optimum temperature. The operating temperatures of various furnaces are given in table 4.4.

Table 4.4 Operating Temperature of Various Furnaces

Slab Reheating furnaces	1200 °C
Rolling Mill furnaces	1200 °C
Bar furnace for Sheet Mill	800 °C
Bogey type annealing furnaces	650 °C -750 °C

Operating at too high temperatures than optimum causes heat loss, excessive oxidation, decarbonization as well as over-stressing of the refractories. These controls are normally left to operator judgment, which is not desirable. To avoid human error, on/off controls should be provided.

4. Prevention of Heat Loss through Openings:

Heat loss through openings consists of the heat loss by direct radiation through openings and the heat loss caused by combustion gas that leaks through openings.

The heat loss from an opening can also be calculated using the following formula:

$$Q = 4.88 \times \left(\frac{T}{100} \right)^4 \times a \times A \times H$$

where,

T: absolute temperature (K)

a: factor for total radiation

A: area of opening, m²

H: time (Hr)

This is explained by an example as follows.

Example-3: A reheating furnace with walls 460 mm thick (X) has a billet extraction outlet, which is 1 m high (D) and 1 m wide. When the furnace temperature is 1,340°C the quantity (Q) of radiation heat loss from this opening is evaluated as follows.

The shape of opening is square, and $D/X = 1/0.46 = 2.17$. Thus, the factor for total radiation is 0.71 (refer Figure 4.3) and we get,

$$Q = 4.88 \times ((1340 + 273)/100)^4 \times 0.71 \times 1 = 234,500 \text{ kcal/hr.}$$

If the furnace pressure is slightly higher than outside air pressure (as in case of reheating furnace) during its operation, the combustion gas inside may blow off through openings and heat is lost with that. But damage is more, if outside air intrudes into the furnace, making temperature distribution uneven and oxidizing billets. This heat loss is about 1% of the total quantity of heat generated in the furnace, if furnace pressure is controlled properly.

5. Control of furnace draft:

If negative pressures exist in the furnace, air infiltration is liable to occur through the cracks and openings thereby affecting air-fuel ratio control. Tests conducted on apparently airtight furnaces have shown air infiltration up to the extent of 40%.

Neglecting furnaces pressure could mean problems of cold metal and non-uniform metal temperatures, which could affect subsequent operations like forging and rolling and result in increased fuel consumption. For optimum fuel consumption, slight positive pressure should be maintained in the furnace as shown in Figure 4.8.

Ex-filtration is less serious than infiltration. Some of the associated problems with ex-filtration are leaping out of flames, overheating of the furnace refractories leading to reduced brick life, increased furnace maintenance, burning out of ducts and equipment attached to the furnace, etc.

In addition to the proper control on furnace pressure, it is important to keep the openings as small as possible and to seal them in order to prevent the release of high temperature gas and intrusion of outside air through openings such as the charging inlet, extracting outlet and peephole on furnace walls or the ceiling.

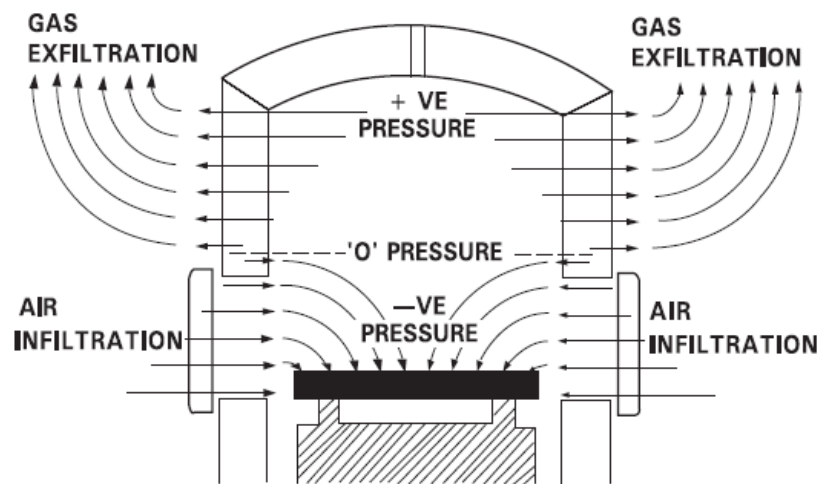


Figure 4.8: Effect of pressure on the location of zero level and infiltration of air

6. Optimum Capacity Utilization:

One of the most vital factors affecting efficiency is loading. There is a particular loading at which the furnace will operate at maximum thermal efficiency. If the furnace is under loaded a smaller fraction of the available heat in the working chamber will be taken up by the load and therefore efficiency will be low.

The best method of loading is generally obtained by trial-noting the weight of material put in at each charge, the time it takes to reach temperature and the amount of fuel used. Every endeavour should be made to load a furnace at the rate associated with optimum efficiency although it must be realised that limitations to achieving this are sometimes imposed by work availability or other factors beyond control.

The loading of the charge on the furnace hearth should be arranged so that,

- It receives the maximum amount of radiation from the hot surfaces of the heating chambers and the flames produced.
- The hot gases are efficiently circulated around the heat receiving surfaces

Stock should not be placed in the following position

- In the direct path of the burners or where impingement of flame is likely to occur.

- In an area which is likely to cause a blockage or restriction of the flue system of the furnace.
- Close to any door openings where cold spots are likely to develop.

The other reason for not operating the furnace at optimum loading is the mismatching of furnace dimension with respect to charge and production schedule.

In the interests of economy and work quality the materials comprising the load should only remain in the furnace for the minimum time to obtain the required physical and metallurgical requirements. When the materials attain these properties they should be removed from the furnace to avoid damage and fuel wastage. The higher the working temperature, higher is the loss per unit time. The effect on the materials by excessive residence time will be an increase in surface defects due to oxidation. The rate of oxidation is dependent upon time, temperature, as well as free oxygen content. The possible increase in surface defects can lead to rejection of the product. It is therefore essential that coordination between the furnace operator, production and planning personnel be maintained.

Optimum utilization of furnace can be planned at design stage. Correct furnace for the jobs should be selected considering whether continuous or batch type furnace would be more suitable. For a continuous type furnace, the overall efficiency will increase with heat recuperation from the waste gas stream. If only batch type furnace is used, careful planning of the loads is important. Furnace should be recharged as soon as possible to enable use of residual furnace heat.

7. Waste Heat Recovery from Furnace Flue Gases:

In any industrial furnace the products of combustion leave the furnace at a temperature higher than the stock temperature. Sensible heat losses in the flue gases, while leaving the chimney, carry 35 to 55 percent of the heat input to the furnace. The higher the quantum of excess air and flue gas temperature, the higher would be the waste heat availability.

Waste heat recovery should be considered after all other energy conservation measures have been taken. Minimizing the generation of waste heat should be the primary objective.

The sensible heat in flue gases can be generally salvaged by the following methods:

- Charge preheating
- Preheating of combustion air
- Utilizing waste heat for other process (to generate steam or hot water by a waste heat boiler)

Charge Pre-heating

When raw materials are preheated by exhaust gases before being placed in a heating furnace, the amount of fuel necessary to heat them in the furnace is reduced. Since raw materials are usually at room temperature, they can be heated sufficiently using high-temperature gas to reduce fuel consumption rate.

Preheating of Combustion Air

For a longtime, the preheating of combustion air using heat from exhaust gas was not used except for large boilers, metal-heating furnaces and high-temperature kilns. This method is now being employed in compact boilers and compact industrial furnaces as well. (Refer Figure 4.9).

A recuperator is a device that recovers heat from exhaust gas exhausted from a furnace. A metallic recuperator has heat transfer surface made of metal, and a ceramic recuperator has heat transfer surface made of ceramics. When the exhaust gas temperature is lower than 1,000°C and air for combustion is preheated, a metallic recuperator is used in general.

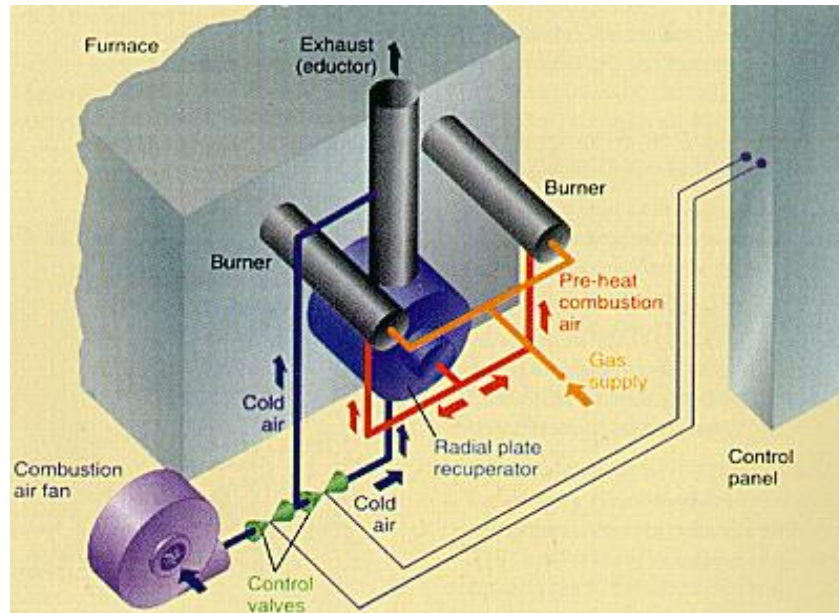


Figure 4.9: Preheating the air for combustion by a recuperator

By using preheated air for combustion, fuel can be saved. The fuel saving rate is given by the following formula:

$$S = \frac{P}{F + P - Q} \times 100(\%)$$

Where,

- S: Fuel saving rate
- F: Calorific value of fuel (kcal/kgfuel)
- P: Quantity of heat brought in by preheated air (kcal/kgfuel)
- Q: Quantity of heat taken away by exhaust gas (kcal/kgfuel)

By this formula, fuel saving rates for heavy oil and natural gas were calculated for various temperatures of exhaust gas and preheated air. The results are shown in the following Figure 4.10 and Figure 4.11.

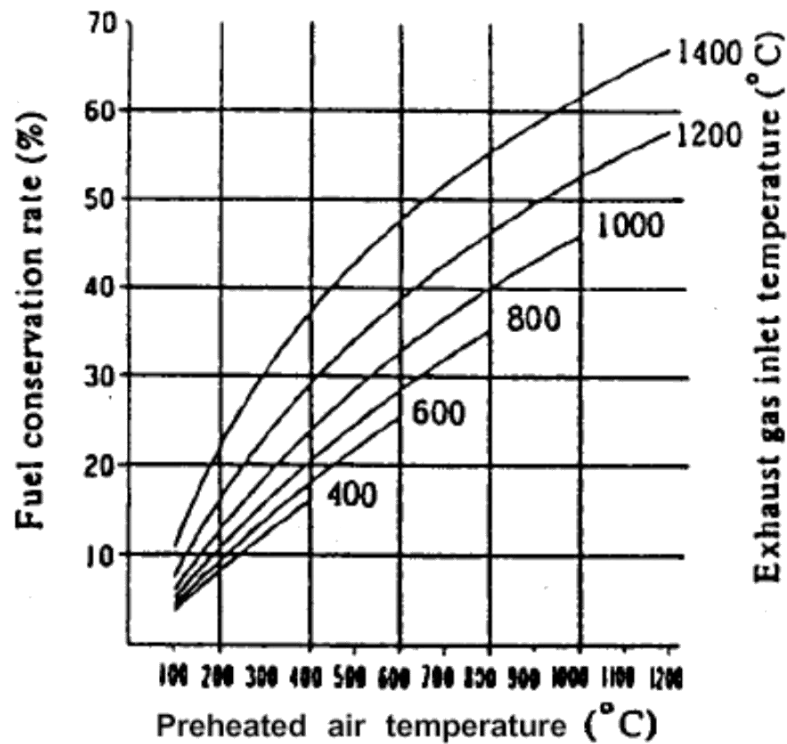


Figure 4.10: Fuel conservation rate when oil is used

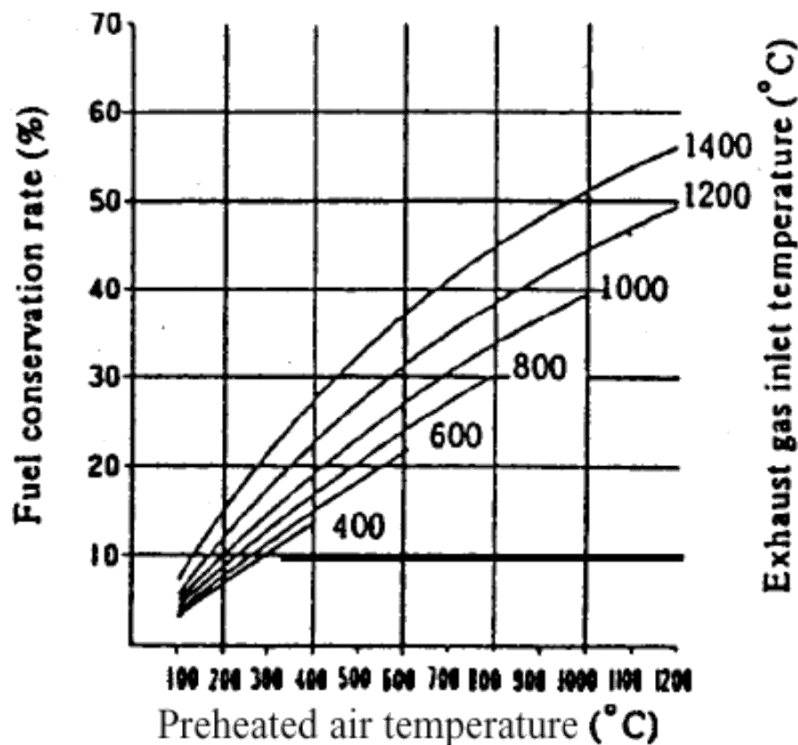


Figure 4.11: Fuel conservation rate when natural gas is used

For example, when combustion air for heavy oil is preheated to 400°C by a heat exchanger with an inlet temperature of 800°C, the fuel conservation rate is estimated to be about 20 percent. When installing a recuperator in a continuous steel reheating furnace, it is important to choose a preheated air temperature that will balance the fuel saving effect and the invested cost for the equipment.

Also, the following points should be checked:

- Draft of exhaust gas: When exhaust gas goes through a recuperator, its draft resistance usually causes a pressure loss of 5-10 mm H₂O. Thus, the draft of stack should be checked.
- Air blower for combustion air: While the air for combustion goes through a recuperator, usually 100-200 mm H₂O pressure is lost. Thus, the discharge pressure of air blower should be checked, and the necessary pressure should be provided by burners.

Since the volume of air is increased owing to its preheating, it is necessary to be careful about the modification of air-duct diameters and blowers. As for the use of combustion gases resulting from high-density oils with a high sulphur content, care must be taken to avoid problems such as clogging with dust or sulphides, corrosion or increases in nitrogen oxides.

Table 4.5 gives details of various air preheaters. In addition, heat-pipe-type heat exchangers and high temperature gas or gas-plate heat exchangers can serve as air preheaters.

Table 4.5: Details of air preheaters

Type				Exhaust Gas Temperature, °C	Preheated Air Temperature, °C	Object Furnace
Recuperative	Metallic recuperate or Chimney installation	Flue installation	Convective: multitubular, other	1000 or below	300 – 600	Heating furnace, heat treatment furnace and other industrial furnaces
			Radiative and convective	1000 – 1300	-do-	-do-
	Ceramic (tile) recuperator			1200 – 1400	400 – 700	Soaking pit and glass
Regenerative	General			1000 – 1600	600 – 1300	Coke oven, hot blast stove & glass kiln
	Rotary regenerative			600	100 - 300	Boiler, hot blast stove

Utilizing Waste Heat as a Heat Source for Other Processes

The temperature of heating-furnace exhaust gas can be as high as 400 –600°C, even after heat has been recovered from it.

When a large amount of steam or hot water is needed in a plant, installing a waste heat boiler to produce the steam or hot water using the exhaust gas heat is preferred. If the exhaust gas heat is suitable for equipment in terms of heat quantity, temperature range,

operation time etc., the fuel consumption can be greatly reduced. In one case, exhaust gas from a quenching furnace was used as a heat source in a tempering furnace so as to obviate the need to use fuel for the tempering furnace itself.

8. Minimizing Wall Losses:

About 30-40% of the fuel input to the furnace generally goes to makeup for heat losses in intermittent or continuous furnaces. The appropriate choice of refractory and insulation materials goes along way in achieving fairly high fuel savings in industrial furnaces.

The heat losses from furnace walls affect the fuel economy considerably. The extent of wall losses depends on:

- Emissivity of wall
- Thermal conductivity of refractories
- Wall thickness
- Whether furnace is operated continuously or intermittently

Heat losses can be reduced by increasing the wall thickness, or through the application of insulating bricks. Outside wall temperatures and heat losses of a composite wall of a certain thickness of fire brick and insulation brick are much lower, due to lesser conductivity of insulating brick as compared to a refractory brick of similar thickness. In the actual operation in most of the small furnaces the operating periods alternate with the idle periods. During the off period, the heat stored in the refractories during the on period is gradually dissipated, mainly through radiation and convection from the cold face. In addition, some heat is abstracted by air flowing through the furnace. Dissipation of stored heat is a loss, because the lost heat is again imparted to the refractories during the heat “on” period, thus consuming extra fuel to generate that heat. If a furnace is operated 24 hours, every third day, practically all the heat stored in the refractories is lost. But if the furnace is operated 8 hours per day all the heat stored in the refractories is not dissipated. For a furnace with a fire brick wall of 350mm thickness, it is estimated that 55percent of the heats to red in there fractories is dissipated from the cold surface during the 16 hours idle period. Furnace walls built of insulating refractories and cased in a shell reduce the flow of heat to the surroundings.

Prevention of Radiation Heat Loss from Surface of Furnace

The quantity of heat release from surface of furnace body is the sum of natural convection and thermal radiation. This quantity can be calculated from surface temperatures of furnace. The temperatures on furnace surface should be measured at as many points as possible, and their average should be used. If the number of measuring points is too small, the error becomes large.

The quantity (Q) of heat release from are heating furnace is calculated with the following formula:

$$Q = a \times (t_1 - t_2)^{5/4} + 4.88E \times \left(\left(\frac{t_1 + 273}{100} \right)^4 - \left(\frac{t_2 + 273}{100} \right)^4 \right)$$

Where,

- Q : Quantity of heat released (kcal/hr/m²)
a : Factor regarding direction of the surface of natural convection ceiling = 2.8,
side walls = 2.2, hearth = 1.5
t₁ : Temperature of external wall surface of the furnace (°C)
t₂ : Temperature of air around the furnace (°C)
E : Emissivity of external wall surface of the furnace

The first term of the formula above represents the quantity of heat release by natural convection, and the second term represents the quantity of heat release by radiation. The following Figure 4.12 shows the relation between the temperature of external wall surface and the quantity of heat release calculated with this formula.

This is explained with an example as follows:

Example-4: There is a reheating furnace whose ceiling, side walls and hearth has 20 m², 50 m², and 20 m² of surface area respectively. Their surface temperatures are measured and the averages are 80°C, 90°C and 100°C respectively. Evaluate the quantity of heat release from the whole surface of the furnace.

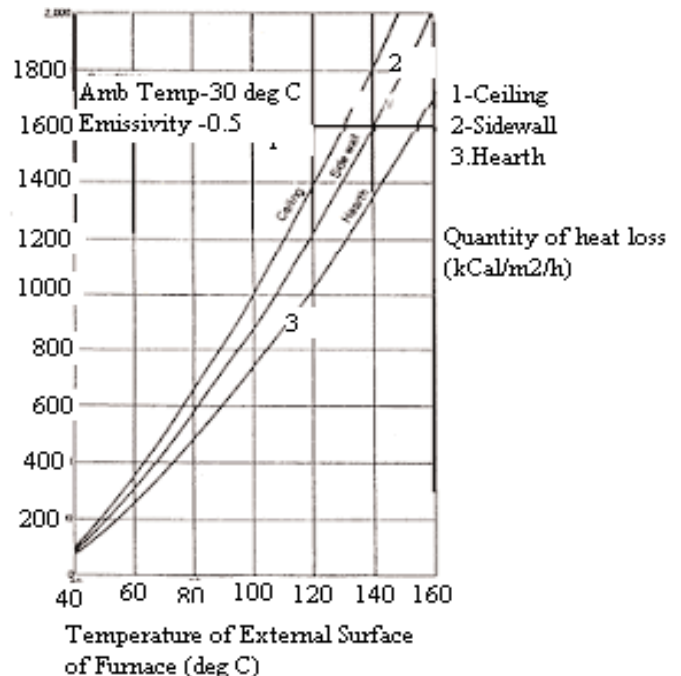


Figure 4.12: Quantity of heat release at various temperature

From the above figure 4.12, the quantities of heat release from ceiling, side walls and hearth per unit area are respectively 650 kcal/m²h, 720 kcal/m²h, and 730 kcal/m²h.

Therefore, the total quantity of heat release is,

$$Q = (650 \times 20) + (720 \times 50) + (730 \times 20) = 13000 + 36000 + 14600 = 63,600 \text{ kcal/hr.}$$

Use of Ceramic Fibre

Ceramic fibre is a low thermal mass refractory used in the hot face of the furnace and fastened to the refractory walls. Due to its low thermal mass the storage losses are minimized. This results in faster heating up of furnace and also faster cooling. Energy savings by this application is possible only in intermittent furnaces.

9. Use of Ceramic Coatings

Ceramic coatings in furnace chamber promote rapid and efficient transfer of heat, uniform heating and extended life of refractories. The emissivity of conventional refractories decreases with increase in temperature whereas for ceramic coatings it increases. This outstanding property has been exploited for use in hot face insulation.

Ceramic coatings are high emissivity coatings which when applied has a long life at

temperatures up to 1350°C. The coatings fall into two general categories-those used for coating metal substrates, and those used for coating refractory substrates. The coatings are non-toxic, non-flammable and water based. Applied at room temperatures, they are sprayed and air dried in less than five minutes. The coatings allow the substrate to maintain its designed metallurgical properties and mechanical strength. Installation is quick and can be completed during shut down. Energy savings of the order of 8-20% have been reported depending on the type of furnace and operating conditions.

Fish Bone Diagram for Energy Conservation Analysis in Furnaces

All the possible measures discussed can be incorporated in furnace design and operation. The figure 4.13 shows characteristics diagram of energy conservation for a fuel-fired furnace.

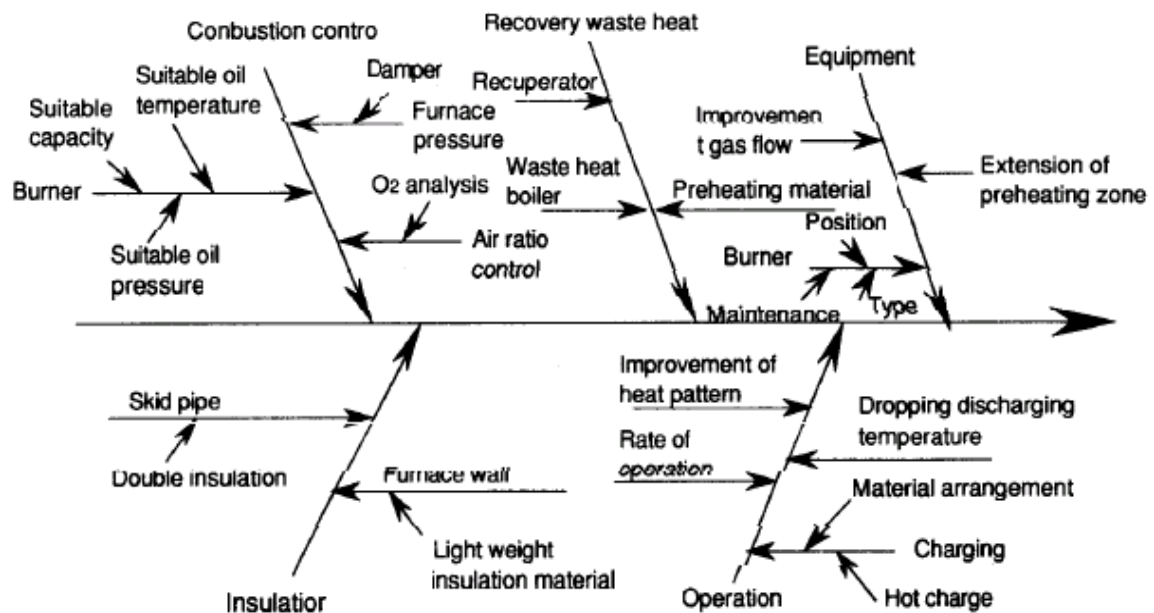


Figure 4.13 Characteristic Diagram of Energy Conservation for Reheating Furnace

4.4. Case Study

In a rolling mill, following energy conservation measures have been implemented and savings achieved are explained below:

Saving by Installing a Recuperator

This plant had a continuous pusher type billet reheating furnace. The furnace consists of two burners at the heating zone. The furnace is having a length of 40 ft. Annual furnace oil consumption is 620 kL. The furnace did not have any waste heat recovery device. The flue gas temperature is found to be 650 °C. To tap this potential heat, the unit has installed a recuperator device. It was possible to preheat the combustion air to 325 °C. By resorting to this measure, there was 15% fuel saving which is 93 KL of oil per annum.

Judicious Use of Combustion Equipment in two Zone Furnaces

During start up the furnace is already filled up with billets of previous day and has a temperature of about 700°C. During initial starting of furnace only the billets in the soaking zone are heated up as there is no movement of billets. Further the flow of heat is from soaking zone to heating zone. Therefore, during starting the soaking zone burners are switched on first and heating zone burners are started only after the mill starts operating.

Similarly, prior to mill stoppage billets lying in soaking zone have already attained re-rolling temperature and the incoming billets from heating zone will not be rolled and hence there is no need to heat those billets. As a result the burners in heating zone are stopped at least 30 to 60 minutes before the stoppage of mill.

The company has saved about 32.4 kL of furnace oil per annum.

Calculations:

- a. During Starting:
Savings by operating 2 nos. of LAP 4 A Wesman burners
30 minutes after starting up = 54 litres
- b. During Shutdown:
Savings by switching off 2 Nos. of LAP Wesman burners
Before 30 minutes of furnace shut down = 54 litres

Total savings per day = 108 litres

Annual Savings = 32.4 KL

Examples:

Problem-5:

Calculate the induction melting furnace efficiency from the following melt cycle data

Mild steel (MS) scrap charged	: 1500 kg
Specific heat of MS	: 0.682 kJ/kg °C
Latent heat of MS	: 272 kJ/kg

MS melting temperature	: 1650 °C
Inlet MS charge temperature	: 40 °C
Electricity consumed during cycle	: 1020 kWh

Ans:

Theoretical energy required for melting kWh	= 1500 (0.682 x (1650 – 40) + 272)/3600
	= 570.8 kWh
Actual input	= 1020 kWh
Furnace efficiency	= 570.8 x 100 / 1020
	= 56%

Problem-6:

In a crude distillation unit of a refinery, furnace is operated to heat 500 m³/hr of crude oil from 255°C to 360°C by firing 3.4 tons/hr of fuel oil having GCV of 9850 kcal/kg. As an energy conservation measure, the management has installed an air pre heater (APH) to reduce the flue gas heat loss. The APH is designed to pre-heat 57 tonnes/hr of combustion air to 195°C.

Calculate the efficiency of the furnace before & after the installation of APH.

Consider the following data:

- Specific heat of crude oil = 0.6 kcal/kg°C
- Specific heat of air = 0.24 kcal/kg°C
- Specific gravity of Crude oil = 0.85
- Ambient temperature = 28°C.

Ans:

Before the installation of APH

Heat gain by the crude	= 500 x 1000 x 0.85 x 0.6 x (360-255)
	= 26775000 kCal/hr
Heat input to the furnace	= 3.4 x 1000 x 9850
	= 33490000 kCal/hr
Efficiency of the furnace	= 26775000 / 33490000
= 80 %	

After the installation of APH

Heat gain by the crude	= 500 x 1000 x 0.85 x 0.6 x (360-255)
	= 26775000 kCal/hr
Heat gain by Air-preheater	= 57 x 1000 x 0.24 x (195-28)
	= 2284560 kCal/hr
Heat reduction in the furnace input	= Heat gain by Air-preheater

$$\begin{aligned}\text{New Heat input to the furnace} &= 33490000 - 2284560 \\ &= 31,205,440 \text{ kCal/hr}\end{aligned}$$

$$\begin{aligned}\text{Efficiency of furnace after installation of APH} &= 26775000 / 31,205,440 \\ &= 85.8 \%\end{aligned}$$

5. INSULATION AND REFRACTORIES

5.1 Insulation

5.1.1 Purpose of Insulation

Insulation is used to prevent heat loss or heat gain to enable less energy consumption while meeting the demands of heating and cooling. A thermal insulator is a poor conductor of heat and has a low thermal conductivity and hence is used in buildings and in manufacturing processes to prevent heat loss or heat gain. Thermal insulation delivers the following benefits:

- Reduces over-all energy consumption
- Offers better process control by maintaining process temperature.
- Prevents corrosion by keeping the exposed surface of a refrigerated system above dew point
- Provides fire protection to equipment
- Absorbs vibration

Insulating materials are porous, containing large number of dormant air cells. Insulation for heating system should be fire proof, be vermin proof, have lasting quality, be mechanically strong, be compact and be light in weight.

5.1.2 Types and Application

The Insulation can be classified into three groups according to the temperature ranges for which they are used. They are

- Low Temperature Insulations (up to 90°C)
- Medium Temperature Insulations (90 – 325°C)
- High Temperature Insulations (325°C – above)

The Table 5.1 describes the characteristics and applications of various insulating materials.

Table 5.1: Characteristics & Applications of various insulating materials

S. No.	Type of Insulation	Application	Characteristics
1	Polystyrene An organic form made by polymerizing styrene	Suitable for low temperatures (-167 °C to 82 °C). Mainly used in - Cool rooms, - refrigeration piping and - concrete retaining structures	Rigid and light weight. Combustible, has a low melting point, is UV degradable, and susceptible to attacks by solvents
2	Polyurethane Made by reacting isocyanates and alcohols. Made in continuous slab or foamed in situ.	Suitable for low temperatures (-178°C to 4 °C). Mainly used in - cool rooms, - refrigerated transports, - deep freezing cabinets, - refrigeration piping, - floor and foundation insulation.	Closed cell structure, low density and high mechanical strength Combustible, produces toxic vapours and has a tendency to smoulder.
3	Rockwool (mineral fibre) Manufactured by melting basalt and coke in a cupola at about 1500 °C. Phenolic binders used.	Suitable for temperatures up to 820 °C. Mainly used to insulate - industrial ovens, - heat exchangers, - driers, - boilers and high temperature pipes	Has a wide density range and is available in matts, blankets, loose form or preformed for pipe insulation. It is chemically inert, non-corrosive and maintains Mechanical strength during handling
4	Fibre Glass Formed by bonding long glass fibres with a thermo setting resin to form blankets and batts, semi-rigid boards, high density rigid boards and preformed pipe sections	Suitable for temperatures up to 540 °C. Mainly used to insulate - industrial ovens, - heat exchangers, - driers, - boilers and pipe works	Will not settle or disintegrate with ageing. Fibre glass products are slightly alkaline pH9 (neutral is pH7). It should not promote or accelerate the corrosion of steel. Hence, it is protected from external contamination.
5	Calcium Silicate Made from anhydrous calcium silicate material reinforced with a non-asbestos binder. Available in slab form of various sizes.	Suitable for temperatures up to 1050 °C. Mainly used to - insulate furnace walls, - fire boxes, - back-up refractory, - flue lining and boilers	Has a minute air cell structure, has a low thermal conductivity and will retain its size and shape in its useable temperature range. It is light weight, but has good structural strength so it can withstand mechanical abrasion. It will not burn or rot, is moisture resistant and non-corrosive.
6	Ceramic Fibre	Suitable for	Suitable for many

	Made from high purity alumina and silica grains, melted in an electric furnace and blasted by high velocity gases into light fluffy fibres. Made in a variety of forms	temperatures up to 1430 °C. Mainly used to insulate • furnace and kiln back-up refractory, • fire boxes, • glass feeder bowls, • furnace repair, induction • coil insulation, • high temperature gaskets and • wrapping material	applications because of the variety of forms. These include cloth, felt, tape, coating cements and variform castable (fire brick)

Classification of insulating materials based on their forms

- **Powdered:** It is mixed with water used to cover odd shapes such as pipe unions, elbows, valves etc.
- **Sheet:** applied to flat areas such as ceilings, ducts, etc.
- **Block and brick:** used to cover outside surfaces of boilers.
- **Blanket:** used to cover ducts, pipes.
- **Tube:** used to insulate steam and hot water pipes.
- **Roll:** used to cover cold and warm-air ducts for furnace castings in hot-air heating systems.
- **Custom Moulded Insulation:** Lagging materials can be obtained in bulk, in the form of moulded sections; semi - cylindrical for pipes, slabs for vessels, flanges, valves etc. The main advantage of the moulded sections is the ease of application and replacement when undertaking repairs for damaged lagging.

5.1.3 Thermal Resistance (R)

The effectiveness of insulation is measured in terms of thermal resistance, called R-value, which indicates the resistance of heat flow. The higher the R-value, the greater the insulating power. The actual R-value of thermal insulation depends on the type of material, its thickness and density. In calculating the R-value of insulation, the R-values of the individual layers are added. The amount of insulation depends on:

- Climate
- Type of fuel used
- The section the requires insulation

Once the type of insulation material that is required is finalized based on temperature of process and the average ambient temperature, the thickness of insulating material required needs to be evaluated.

5.1.4 Economic Thickness of Insulation (ETI)

The effectiveness of insulation follows the law of decreasing returns. Hence, there is a definite economic limit to the amount of insulation, which is justified. An increased thickness is uneconomical and cannot be recovered through small heat savings. This limiting value is termed as economic thickness of insulation. An illustrative case is given in Figure 5.1. Each industry has different fuel cost and boiler efficiency. These values can be used for calculating economic thickness of insulation. This shows that thickness for a given set of circumstances results in the lowest overall cost of insulation and heat loss combined over a given period of

time. The following figure 5.1 and 5.2 illustrates the principle of economic thickness of insulation.

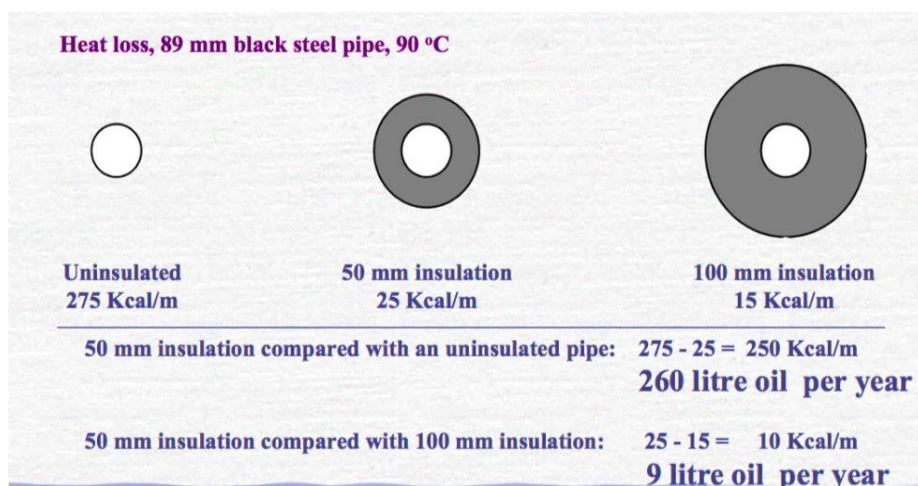


Figure 5.1: Illustration of optimal insulation

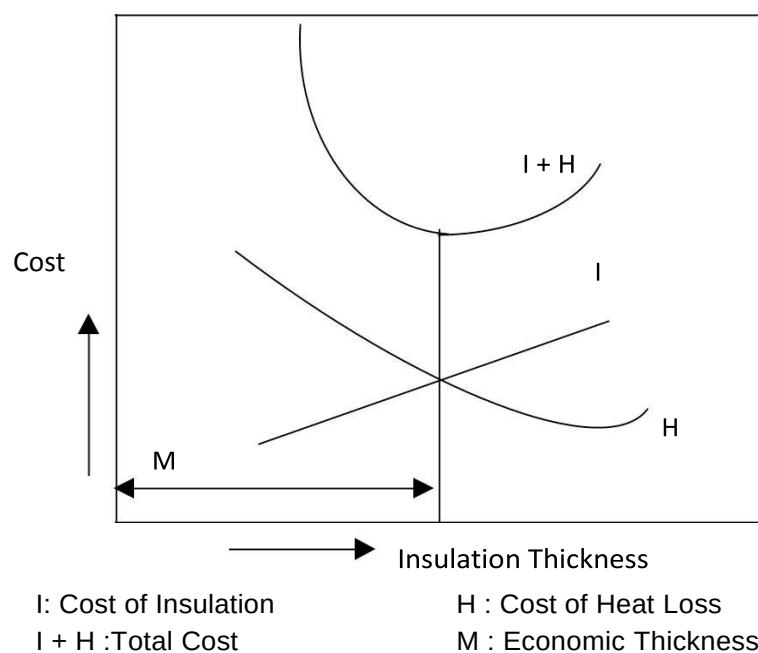


Figure 5.2: Determination of economic thickness of insulation

Heat loss from a surface is expressed as

$$H = h \times A \times (T_h - T_a)$$

Where,

- h is Heat transfer coefficient, W/m² K (2000 W/ m² K)
- H is Heat loss, Watts
- T_a is Average ambient temperature, °C
- T_h is Hot surface temperature (for hot fluid piping) in °C & Cold surface temperature (for cold fluids piping) in °C

The point where the amount of insulation gives the greatest return on investment is called as **“economic thickness of insulation (ETI)”**. The determination of economic thickness requires the attention to the following factors.

- Cost of fuel

- Annual hours of operation
- Heat content of fuel
- Boiler efficiency
- Operating surface temperature
- Pipe diameter/thickness of surface
- Estimated cost of insulation.
- Average exposure ambient still air temperature.

The cost of insulation depends not only on the thickness of insulating material but also on the material itself. Materials with higher thermal resistance will require insulating material of less thickness compared to insulating material with lower thermal resistance. At the same time cost of higher thermal resistance for same thickness may be higher compare to insulating material with lower thermal resistance.

5.1.5 Heat Savings and Application Criteria

Various charts, graphs and references are available for heat loss computation. The surface heat loss can be computed with the help of a simple relation as given below. This equation can be used up to 200 °C surface temperature. Factors like wind velocities, conductivity of insulating material etc. has not been considered in the equation.

$$S = \left[10 + \frac{T_s - T_a}{20} \right] (T_s - T_a)$$

Where

- S = Surface heat loss in Kcal/hr m²
 T_s = Hot surface temperature in °C
 T_a = Ambient temperature in °C

$$\text{Total heat loss/hr (Hs)} = S \times A$$

Where,

- A = Surface area in m²

Based on the cost of heat energy, the quantification of heat loss in BDT can be worked out as under:

$$\text{Equivalent fuel loss (Hf)} \left(\frac{\text{kg}}{\text{yr}} \right) = \frac{H_s \times \text{Yearly hours of operation}}{\text{GCV} \times \eta_b}$$

$$\text{Annual heat loss in monetary terms (BDT)} = Hf \times \text{Fuel cost (BDT/kg)}$$

Where

- GCV = Gross Calorific value of fuel Kcal/Kg
 η_b = Boiler efficiency in %

Example

Consider a 50m pipe of 150 mm outer diameter carrying process fluid at 150°C. The ambient temperature is 20 °C. The heat is supplied by boiler operating at 80% efficiency and the cost of fuel which is HSD with GCV of 10000 Kcal/ lit is BDT 50/liter. It is considered to insulate this pipe with semi-cylindrical pre-fabricated glass mineral fibre with a life of 5 years. The cost of glass mineral fiber of various thickness and the surface temperature achievable after insulation for calculation purpose is given below.

Thickness, mm	Cost, BDT/m	Surface Temperature. after insulation, °C
25	500	65
50	600	48
75	750	43
100	900	40

Calculate fuel saved by using above thickness levels of insulation. Draw a graph of Costs of insulation vs thickness and identify the economic thickness of insulation required.

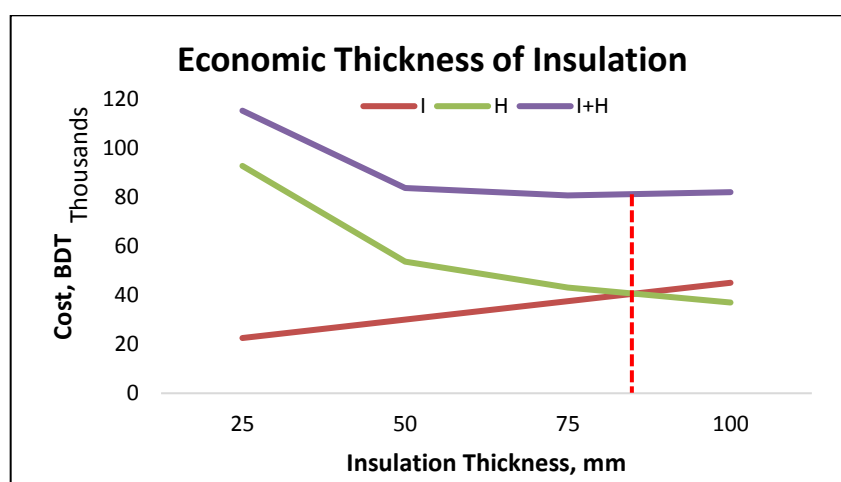
Methodology:

- Step 1: Calculate the surface area of pipe
- Step 2: Calculate unit heat loss and using surface area calculate total surface heat loss with and without insulation.
- Step 3: Convert heat loss to fuel loss using calorific value of fuel used in boiler. Adjust fuel usage to boiler efficiency. Convert hourly loss to yearly loss.
- Step 4: Using unit fuel cost data estimate fuel loss in cost terms for the entire life of insulating material i.e. 5 years.
- Step 5: Using given insulating material costs estimate cost of insulation for varying thickness of the insulating material.
- Step 6: Calculate the total cost of insulation and fuel loss cost.
- Step 7: Plot graph of Insulation thickness v/s Cost of insulating material, Cost of fuel loss and total cost.
- Step 8: Identify the economic thickness of insulating material by drawing a vertical line at the point of intersection of cost of insulating material and cost of fuel loss lines.

Economic thickness of insulation for 150 mm dia pipe					
Step 1					
	Unit				
Insulation Thickness	mm	25	50	75	100
Length of pipe, l	m	50			
Bare pipe outer diameter, d	mm	150			
	$Surface\ Area = \pi \times d \times l$				
Bare pipe surface area	m2	23.56	23.56	23.56	23.56
Step 2					
Ambient Temperature	°C	20			
Surface Temperature					
-before insulation	°C	150			
-after insulation	°C	65	48	43	40
Surface heat loss		$S = \left[10 + \frac{T_s - T_a}{20} \right] (T_s - T_a)$			
-without insulation	Kcal/hr.m ²	2145			
-after insulation	Kcal/hr.m ²	551.25	319.2	256.45	220
Heat loss reduction	Kcal/hr.m ²	1594	1826	1888	1925
Step 3					
Total energy saved (H _s)	Kcal/year	13387500	15336720	15863820	16170000
Yearly hours of operation	hrs	8400			
GCV	Kcal/Lit	10000			
Boiler Efficiency	%	80			
$Equivalent\ fuel\ loss\ (H_f) \left(\frac{Lit}{yr} \right) = \frac{H_s \times Yearly\ hours\ of\ operation}{GCV \times \eta_b}$					
Total fuel energy lost per year	Lit/year	370	215	172	148
$Fuel\ Saving = Fuel\ Loss\ without\ insulation - Fuel\ loss\ with\ insulation$					
Yearly fuel savings	Lit/year	1071	1227	1269	1294
Step 4					

Life cycle heat loss in monetary terms (BDT) $= H_f \times \text{Life of insulation} \times \text{Fuel cost (BDT/lit)}$					
Fuel Cost	BDT/Lit	50			
Cost of fuel loss					
-without insulation	BDT/5 yrs	360360			
-with insulation [H]	BDT/ 5yrs	92610	53626	43084	36960
Step 5					
Cost of insulation	BDT/m	450	600	750	900
Total cost of insulation [I]	BDT	22500	30000	37500	45000
Step 6					
Total Cost (insulation & fuel loss) [I+H]	BDT	115110	83626	80584	81960

Step 7:



Step 8: From the above graph it can be seen that economic thickness of insulation is 80mm.

5.2 Refractories

Refractories are non-metallic materials have insulating and other chemical and physical properties that make them able to contain the heat generated by burning of the fuel in the furnace and to minimise heat losses, withstand high temperatures and make them applicable for structures, or as components of systems, that are exposed to environments above 1,000 °F (811 K; 538 °C) and should not contaminate the material with which it is in contact. Refractory materials are used in furnaces, kilns, incinerators, and reactors.

The various combinations of operating conditions under which refractories are used, make it necessary to manufacture a range of refractory materials with different properties and accordingly are made in varying combinations and shapes for different applications. A furnace designer should have a clear idea of the service conditions of different refractory and for which the refractory is being used and needs to consider the following points, before selecting a refractory.

- Area of application
- Working temperatures
- Extent of abrasion and impact
- Structural load of the furnace
- Stress due to temperature gradient in the structures and temperatures fluctuations
- Chemical compatibility with the furnace environment
- Heat transfer and fuel conservation
- Cost consideration

5.2.1 Selection of Refractories

The selection of refractories for any particular application is made with a view to achieve the best performance of the equipment furnace, kiln or boiler and depends on their properties. Further, the choice of a refractory material for a given application will be determined by the type of furnace or heating unit and the prevailing conditions e.g. the gaseous atmosphere, the presence of slags, the type metal charges etc. It is, therefore, clear that temperature is by no means the only criterion for selection of refractories. Important physical properties of some insulating refractories that are considered in selecting them are shown in the following Table 5.2.

Table 5.2: Physical properties of some insulating refractories

Type/grade	Thermal Conductivity at 400 °C	Max. safe Temp °C	Cold Crushing Strength Kg/cm ²	Porosity %	Bulk Density Kg/m ²
Diatomite Solid	0.025	1000	270	52	1090
Diatomite Porous	0.014	800	110	77	540
Clay	0.030	1500	260	68	560
High Alumina	0.028	1500-1600	300	66	910
Silica	0.040	1400	400	65	830

Besides the physical properties chemical properties and the working atmosphere where these are used also influence their selection. Considering these factors refractories are classified based on the refractory constituents, behavior of the refractory constituents in their working atmosphere, and the form of refractory application

5.2.2 Classification of Refractories

Refractories are classified based on their refractoriness, based on chemical composition of refractories, their form and operating temperatures.

Classification based on refractoriness

Based on the property of refractoriness, they are usually classified into four classes using their PCE¹ (pyro metric cone equivalent) value as given in table 5.3.

Table 5.3: Classification of Refractories based on PCE Value

Class of Refractory	PCE value
Super duty refractories	33 - 38
High duty refractories	30 - 33
Intermediate duty refractories	28 - 30
Low duty refractories	19 - 28

Classification based on composition of Refractories

Refractories can be classified on the basis of chemical composition and method of manufacture. The constituents, characteristics and applications of these refractories are summarized in table 5.4.

Table 5.4: Classification of Refractories based on Materials, their characteristics and applications

Refractory Type	General Characteristics	Application
Acid Bricks: Used in areas where both slag and atmosphere are acidic and are attacked by alkalis (basic slags).		
Silica	High strength at high temperatures, residual expansion, low specific gravity, high expansion coefficient at low temperatures, low expansion coefficient at high temperatures	Glass tank crown, copper refining furnace, electric arc furnace roof
Fused silica	Low thermal expansion coefficient, high thermal shock resistance, low thermal conductivity, low specific gravity, low specific heat	Coke over, hot stove, soaking pit, glass tank crown
Fireclay (Chamotte)	Consists of kaolinite ($\text{Al}_2\text{O}_3 \cdot 2\text{SiO}_2 \cdot 2\text{H}_2\text{O}$) and minor amounts of other clay materials. Low thermal expansion coefficient. Low thermal conductivity, low specific gravity, low specific	Ladle, runner, sleeve, coke oven, annealing furnace, blast furnace hot stove, reheating furnace, soaking pit

¹The pyrometric cone is "A pyramid with a triangular base and of a defined shape and size; the "cone" is shaped from a carefully proportioned and uniformly mixed batch of ceramic materials so that when it is heated under stated conditions, it will bend due to softening, the tip of the cone becoming level with the base at a definitive temperature. Pyrometric cones are made in series, the temperature interval between the successive cones usually being 20 degrees Celsius. The number of that standard pyrometric cone whose tip would touch the supporting plaque simultaneously with a cone of the refractory material being investigated when tested in accordance with ASTM Test Method C-24.

Refractory Type	General Characteristics	Application
	heat, low strength at high temperatures, less slag penetration	
Alumina	High refractoriness, high mechanical strength, high slag resistance, high specific gravity, relatively high thermal conductivity	Hot stove, stopper head, sleeve, soaking pit cover, reheating furnace, glass tank, high-temperature kiln.
High alumina	Composed of bauxite or other raw materials that contain 50 to 87.5 percent alumina. High refractoriness, high mechanical strength, high slag resistance, high specific gravity, relatively high thermal conductivity	Slide gate, aluminium melting furnace, skid rail, ladle, incinerator, reheating furnace hearth.
Roseki	Low thermal expansion coefficient, high thermal shock resistance, low thermal conductivity, low specific gravity, low specific heat	Ladle, runner, sleeve, coke oven, hot stove, soaking pit, annealing, blast and reheating furnace.
Zircon	Containing Zirconium silicate (ZrO_2SiO_2). Maintains good volume stability for extended periods, has high thermal shock resistance, high slag resistance, high specific gravity	Ladle, nozzle, stopper head, sleeve
Zirconia	High melting point, low wet tability against molten metal, low thermal conductivity, high corrosion resistance, high specific gravity	Nozzle for continuous casting, glass tank, high-temperature furnace, crucible.
Alumina zirconia silica	High slag resistance, high corrosion resistance against molten glass	Glass tank, incinerator, ladle, nozzle for continuous casting
Mullite	Made from kyanite, sillimanite, andalusite, bauxite or mixtures of alumina silicate materials; mullite refractories are about 70% alumina. They maintain a low level of impurities and high resistance to loading in high temperatures and offers good thermal shock resistance, excellent thermal stability, resistance to most chemical attack, resistance to abrasion and good electrical resistivity.	Steel ladles, lances, reheat furnaces and slide gates are examples of mullite aggregate based products with various alumina contents. In kiln areas such as kiln setter slabs and posts for supporting ceramic ware during firing
Basic Bricks: Are stable to alkaline slags, dusts and fumes at high temperatures and are attacked by acid slags.		
Lime	High slag resistance, low hydration resistance	Special refining surface
Magnesia	High refractoriness, relatively low strength at high temperature, high basic slag resistance, low thermal shock resistance, low durability at high humidity	Hot-metal mixer, secondary refining vessel, rotary kiln, checker chamber of glass tank, electric arc furnace
Magnesia-chrome	High refractoriness, High refractoriness under load, high basic slag resistance, relatively good thermal shock resistance (low MgO bricks), high strength at high temperature (direct bonded and fusion cast)	Hot-metal mixer, electric arc furnace, secondary refining vessel, nonferrous refining furnace, rotary cement kiln, lime and dolomite kiln, copper furnace, ladle, checker chamber of glass tank, slag line of electric arc furnace, degasser for copper, non-ferrous smelter.
Dolomite	High refractoriness under load, high basic slag resistance, low durability in high humidity, high thermal expansion coefficient	Basic oxygen furnace, electric arc furnace, secondary refining vessel, rotary cement kiln.
Spinel	High thermal shock resistance, high strength at high temperatures, high slag resistance	Rotary cement kiln, ladle.
Neutral Non-oxide Bricks : are chemically stable to both acids and bases and are used in areas where slag and atmosphere are either acidic or basic		

Refractory Type	General Characteristics	Application
Chrome	High refractoriness, low strength at high temperature, low thermal resistance	Buffer brick between acid and base brick
Silicon carbide	They are produced by the reaction of sand and coke in an electric furnace. High refractoriness, high strength at high temperature, high thermal conductivity, high thermal shock resistance, reduced oxidation resistance at high temperature, high slag resistance	Kiln furniture, incinerator, blast furnace
Silicon carbide-graphite	High refractoriness, high strength at high temperature, high thermal conductivity, high thermal shock resistance	Incinerator
Silicon nitride	High strength, high thermal shock resistance, relatively high oxidation resistance	Kiln furniture, blast furnace
Composite		
Silicon carbide containing	High corrosion resistance against low iron oxide, high strength at high temperatures, high thermal shock resistance	Ladle, blast furnace, electric arc, torpedo ladle, iron ladle
Magnesia-carbon	High slag resistance, high thermal shock resistance	Basic oxygen furnace, electric arc furnace, ladle
Alumina-carbon	High refractoriness, high thermal shock resistance, high corrosion resistance	Submerged entry nozzle, slide gate

Classification based on Form of Refractories

Refractories and refractory materials are used in various forms depending on the requirements. Table 5.5 gives different forms in which these are produced.

Table 5.5: Forms of Refractories

Kind	Definition
Shaped Refractories	
Bricks	Refractories that have shapes and are used to line furnaces, kilns, glass tanks, incinerators, etc.
Insulating firebrick	Low thermal conductivity firebrick.
Unshaped Refractories (Monolithic)	
Mortar	Materials for bonding bricks in a lining. The three types of mortar – heat-setting; air-setting; and hydraulic-setting – have different setting mechanisms.
Castables	Refractory materials are mixed with hydraulic-setting cement (either Portland or a high-alumina cement) and casted. Used to line furnaces, kilns, formation of the bases of tunnel kiln cars used in the ceramic industry etc.
Plastics	Refractories in which raw materials and plastic materials are mixed with water. Plastic refractories are roughly formed, sometimes with chemical additives.
Gunning mixes	Refractories that are sprayed on the surface by a gun.
Ramming mixes	Granular refractories that are strengthened by gunning formulation of a ceramic bond after heating. Ramming mixes have less plasticity and are installed by air rammer.
Slinger mixes	Refractories installed by a slinger machine.
Patching materials/ coating materials	Refractories with properties similar to refractory mortar. However, patching materials have controlled grain size for easy patching or coating.
Light weight	These are porous lightweight materials which are mixed with hydraulic

castables	cement and water and formed by casting. Lightweight castables are used to line furnaces, kilns, etc.
Fibrous Materials	
Ceramic fiber	Ceramic fibre is analumino silicate or ZrO ₂ added alumino silicate material manufactured by blending and melting alumina and silica at temperature of 1800–2000 °C and fibre made by blowing compressed air or dropping the melt on spinning disc. There are produced as in blanket, felt, module, vacuum, rope, or loose fiber form.

Recommended operating temperatures for continuous operations are given in the Table 5.6.

Table 5.6: Recommended operating temperature for Continuous Operation

	Al ₂ O ₃ %	SiO ₂ %	ZrO ₂ %
1150 °C	43-47	53-57	-
1250 °C	52-56	44-48	-
1325 °C	33-35	47-50	17-20

5.3 High Emissivity Coatings

Emissivity is the measure of a material's ability to both absorb and radiate heat. The high emissivity materials when coated increases the surface emissivity of materials, with resultant benefits in heat transfer efficiency and in the service life of heat transfer components like refractories and metallic components such as radiant tubes and heating elements. High emissivity coatings are applied in the interior surface of furnaces or where rapid heating is required. The use of such coatings was found to reduce fuel or power to tune of 25-45%. The Figure 5.3 shows emissivity of various insulating materials including high emissivity coatings. High emissivity coating shows a constant value over varying process temperatures.

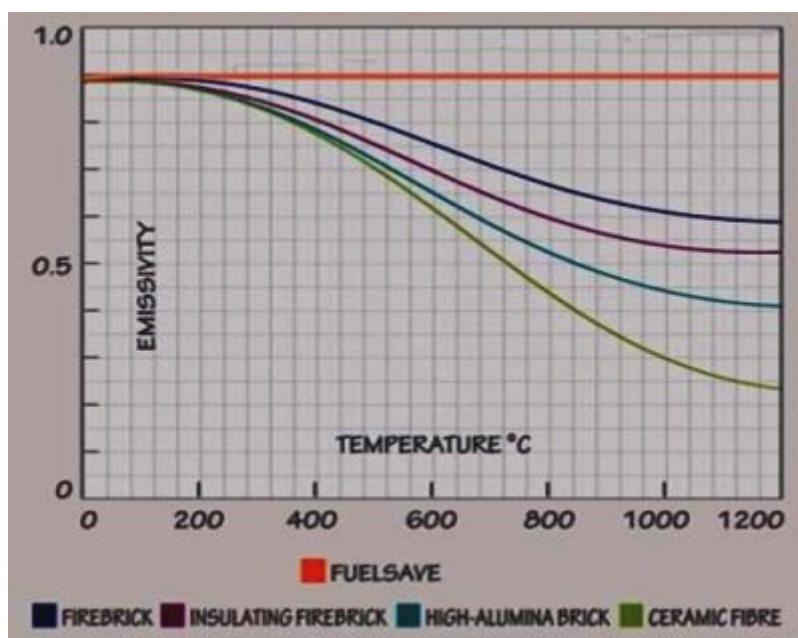


Figure 5.3: Emissivity of refractory materials at different temperatures

Furnaces, which operate at high temperature, have emissivity of 0.3. By using high emissivity coatings this can go upto 0.8 thus effectively increasing the radiative heat transfer.

6 FBC BOILERS

6.1 Introduction

The traditional grate fuel firing systems have got limitations and are techno-economically unviable to meet the challenges of future. Fluidized bed combustion has significant advantages over conventional firing systems and offers multiple benefits. Since its introduction in the 1970s the technology has gained acceptance in various industrial applications.

It is known for its ability to burn low-grade fuels with low calorific value, high ash content and high moisture content. The fuels being burnt in these boilers include coal, washery rejects, rice husk, bagasse & other agricultural wastes, and their capacities range from 0.5 T/hr. to 74T/hr.

Other advantages are fuel flexibility, emission performance, re-use of non-hazardous by-products (e.g. gypsum) and the possibility of the technology to be implemented in an existing plant (retrofit).

6.2 Fundamentals of FBC

A fluidized bed consists of a stream of gas flowing upward through a bed of solid particles such as ash or sand. At low gas flow rates, the gas permeates through the bed without disturbing the particles and is called a **packed bed**. As the gas flow rate increases, the force exerted on the particles becomes greater until eventually the gas stream supports the particles and the bed becomes "**fluidized**." This causes the particles to separate and the bed to expand. The gas velocity at this point is termed **the minimum fluidizing velocity**. As the gas velocity is increased further, bubbles form and rise through the bed. Bubbles passing through the bed cause a highly turbulent mixing of the particles and give the bed the appearance of a boiling fluid. At this point, a bed surface or the boundary separating the bed material and the space above it is visible. This bed is called a "**bubbling bed**." As the gas velocity is further increased, the smaller particles become entrained in the gas stream and are transported from the bed. If the velocity is increased sufficiently, a condition would be reached where all the particles would be transported from the bed and a distinct bed surface is no longer apparent. A system (at this velocity) with a collection device to separate the gas and return the particles to the bed area is called a "**circulating bed**." This phenomenon of fluidization with increasing gas velocity is illustrated in figure 6.1.

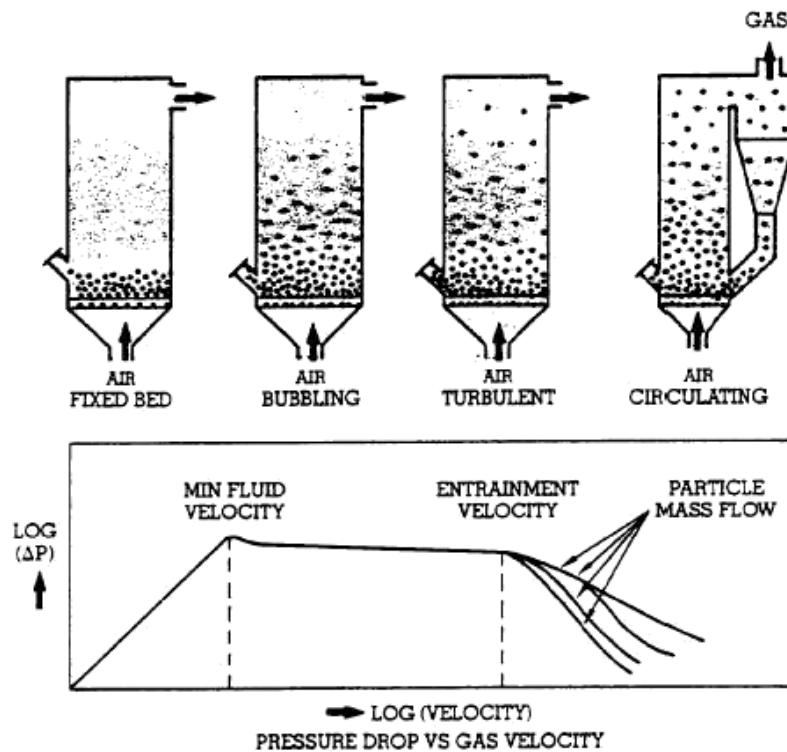


Figure 6.1: Principle of fluidization

With higher air velocities, the bed particles leave the combustion with the flue gases so that solids recirculation is necessary to maintain circulating fluidized bed. The mean solids velocity increases at a slower rate than does the gas velocity, as illustrated in Figure 6.2. Therefore, a maximum slip velocity between the solids and the gas can be achieved resulting in good heat transfer and contact time between solids and gas.

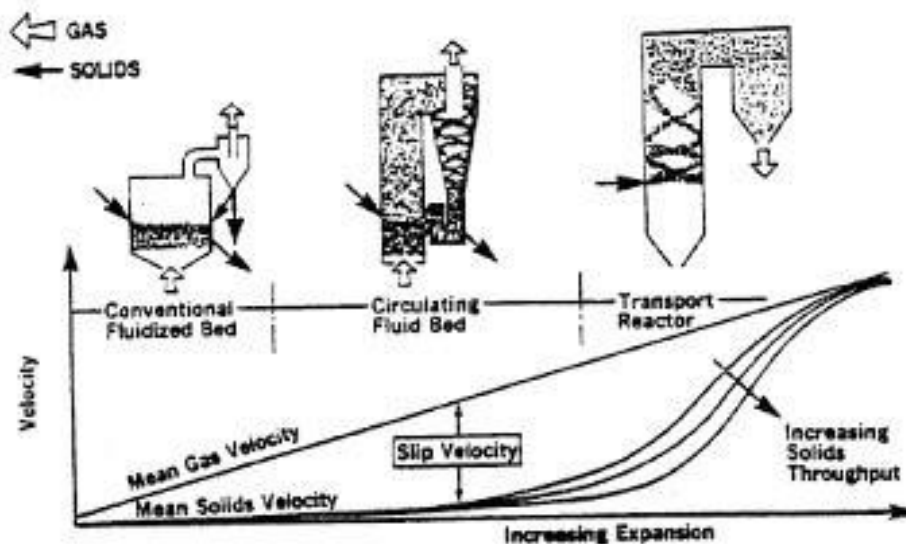


Figure 6.2: Relation between gas velocity and solid velocity

A fluidized bed combustion boiler is one where combustion takes place over a fluidized bed. If the sand in a fluidized state is heated to the ignition temperature of the coal and the coal is injected continuously into the bed, the coal will burn rapidly and the bed attains a uniform temperature due to effective mixing. This, in essence, is fluidized bed combustion.

The furnace combustion takes place at about 840°C to 950°C. To start a cold boiler, the bed is first preheated to around 540°C by passing through the combustion products from an auxiliary heater. At this temperature solid fuel could be ignited. Fuel is then introduced either from the base or the top of the bed. Heated fluidizing air is blown through the distributor plate to supply the primary combustion air. Combustion is continued in the freeboard space where secondary air is supplied for completing the combustion.

The combustion of fuel with air can produce flame temperatures in excess of 1650°C, which can lead to catastrophic material failure. To prevent such problems in bed operations, the temperature must be kept below 1100 °C, temperature much below the ash fusion temperature, and is never allowed to reach adiabatic combustion temperature to avoid melting of ash. This is achieved usually by using in-bed boiler tubes (a heat sink) in combination with controlling the fuel content in the bed to, for example, less than 5%.

A typical FBC boiler plant is shown schematically in figure 6.3

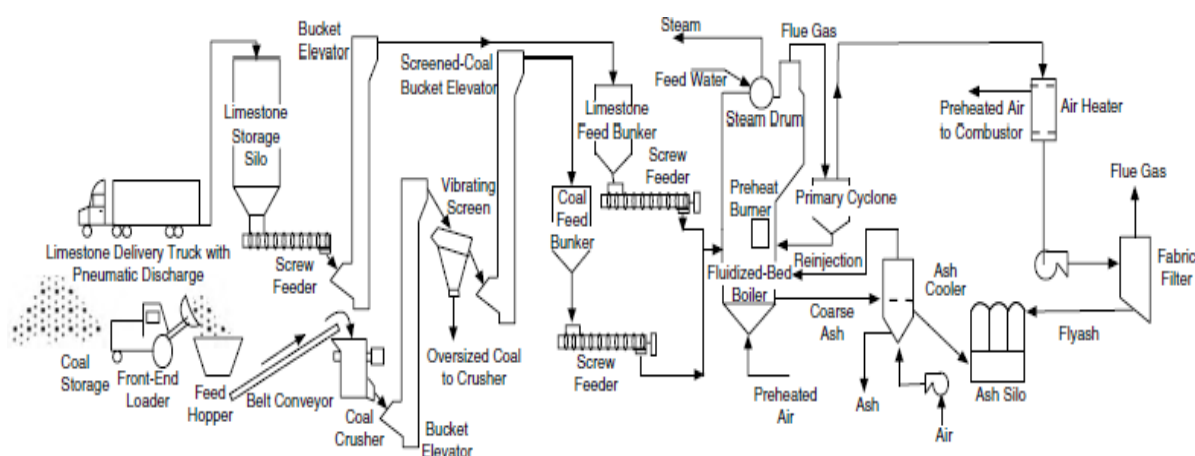


Figure 6.3: Typical fluidized bed boiler plant firing solid fuels

6.2.1 Components of FBC Boiler

A FBC boiler normally will have the following seven principal components as shown in figure 6.3.

1. Feeder for Fuels and Sulfur Sorbents.
2. Air Movers.
3. Air Distributor.
4. Plenum Chamber.
5. Combustion Chamber.
6. Solid Withdrawal System.

6.2.1.1 Fuel Feeders

For feeding fuel and sorbent like limestone or dolomite, usually two methods are followed as explained below:

Under Bed Pneumatic Feeding: If the fuel is coal, it is crushed to 1-6mm size and pneumatically transported from feed hopper to the combustor through a feed pipe piercing the distributor. Based on the capacity of the boiler, the number of feed points increases, as it is necessary to distribute the fuel into the bed uniformly.

Over-Bed Feeding: The crushed coal, 6-10 mm size is conveyed from coal bunker to a spreader by a screw conveyor.

The spreader distributes the coal over the surface of the bed uniformly. This type of fuel feeding system accepts over size fuel also and eliminates transport lines, when compared to under-bed feeding system.



Figure 6.4: Types of Fuel Feeder

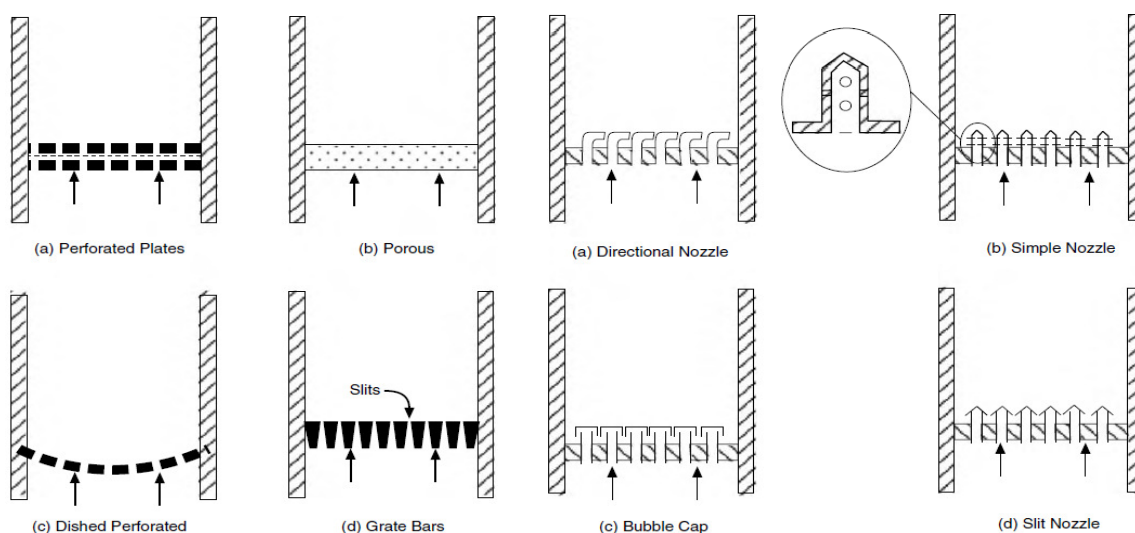
There are broadly four types of industrial feeders: gravity chute, screw feeder, spreader, and pneumatic feeders.

6.2.1.2 Air Movers.

Air movers supply air for combustion and fluidization of the burning fluidized bed and pneumatic transportation of solid matters such as coal, limestone, and ash.

6.2.1.3 Air Distributor

An essential function of the distributor is to introduce the fluidizing air evenly through the bed cross section to keep the solid particles in constant motion, and prevent formation of defuidization zones within the bed. The distributor is normally constructed from metal plate with a number of perforations, in a definite geometric pattern. The perforations may be located in simple nozzles or nozzles with bubble caps, which serve to prevent solid particles from flowing back into the space below the distributor.



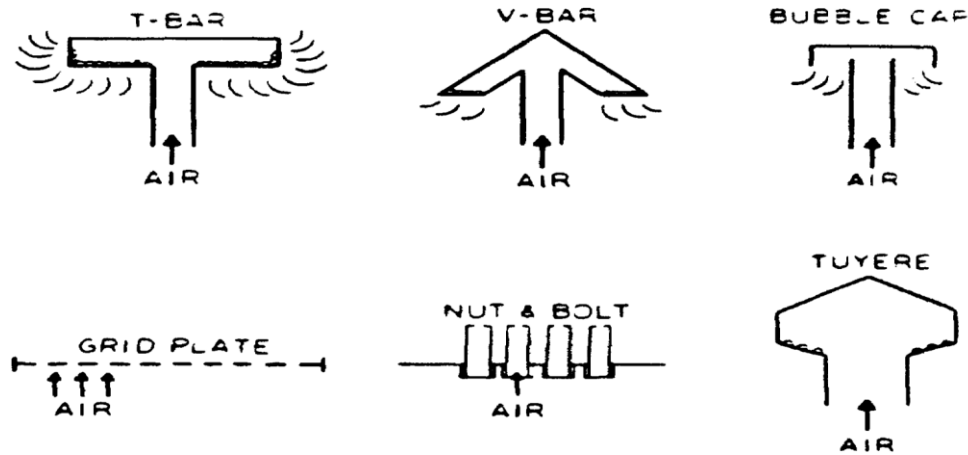


Figure 6.5: Air Distributors and Nozzles

The distributor plate forms the furnace floor and this is protected from high temperature of the furnace by:

- Refractory Lining
- A Static Layer of the Bed Material or
- Water Cooled Tubes.

6.2.1.4 Plenum Chamber

The plenum chamber is located directly underneath the distributor. Fluidizing air enters the distributor by way of the plenum chamber. The plenum chamber serves to minimize air pressure surges, and to contain the spent materials that drifted (weeping) through the distributor. The function of the air box is to distribute the air under the grid as uniformly as possible.

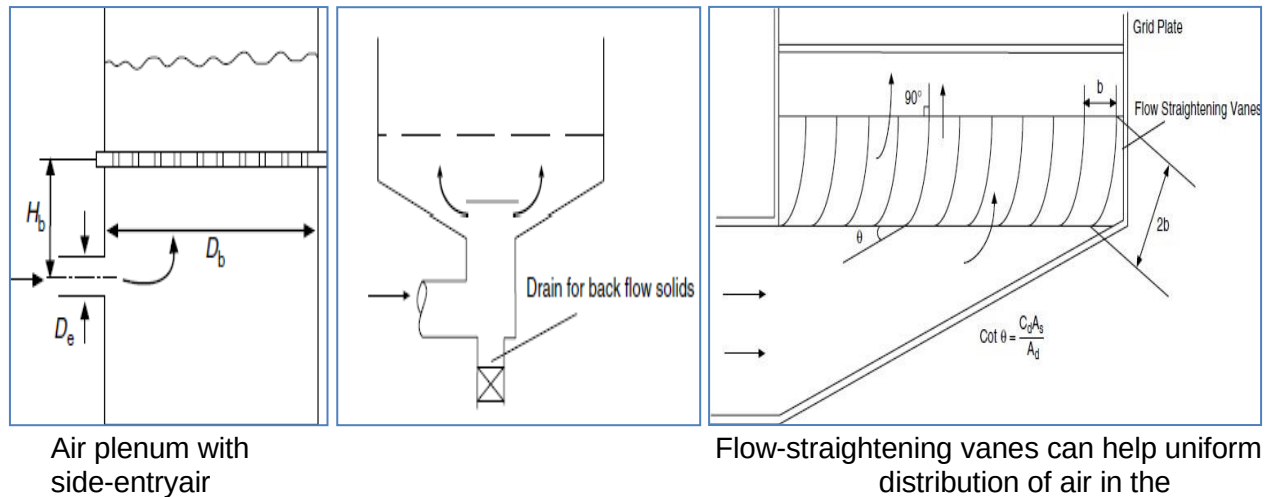


Figure 6.6: Types of Plenum Chamber

6.2.1.5 Bed & In - Bed Heat Transfer Surface:

Bed Heat Transfer Surface: Depending on the bed height these are of two types with average bed particle size of about 1 mm:

- Shallow bed and
- Deep bed.

At the same fluidizing velocity, the two ends fluidize differently, thus affecting the heat transfer to an immersed heat transfer surfaces. A shallow bed offers a lower bed resistance and hence a lower pressure drop and lower fan power consumption. In the case of deep bed, the pressure drop is more and this increases the effective gas velocity and also the fan power.

In - Bed Heat Transfer Surface: In a fluidized in-bed heat transfer process it is necessary to transfer heat between the bed material and an immersed surface, which could be a tube bundle, or a coil. The heat exchanger orientation can be horizontal, vertical or inclined. From a pressure drop point of view, a horizontal bundle in a shallow bed is more attractive than a vertical bundle in a deep bed. Also, the heat transfer in the bed depends on number of parameters like

- (i) Bed pressure
- (ii) Bed temperature
- (iii) superficial gas velocity
- (iv) particle size,
- (v) Heat exchanger design and
- (vi) Gas distributor plate design.

6.2.1.6 Ash Removal System

Bed ash removal: In the FBC boilers, the bottom ash constitutes roughly 30 - 40 % of the total ash, the rest being the fly ash. The bed ash is removed by both continuous over flow, to maintain bed height, and also by intermittently from the bottom to remove over size particles to avoid accumulation and consequent defluidization. While firing high ash coal such as washery rejects, the bed ash over flow drain quantity is considerable so special care has to be taken.

Fly ash removal: The amount of fly ash to be handled in FBC boiler is relatively very high, when compared to conventional boilers. This is due to elutriation of particles at high velocities. Fly ash carried away by the flue gas is removed in number of stages. Firstly in convection section, then from the bottom of air pre heater/economizer, and a major portion in dust collectors.

The type of dust collectors used are cyclone, bag filters, electrostatic precipitators (ESP's) or some combination of all of these. To increase the combustion efficiency, recycling of fly ash is practiced in some of the units.

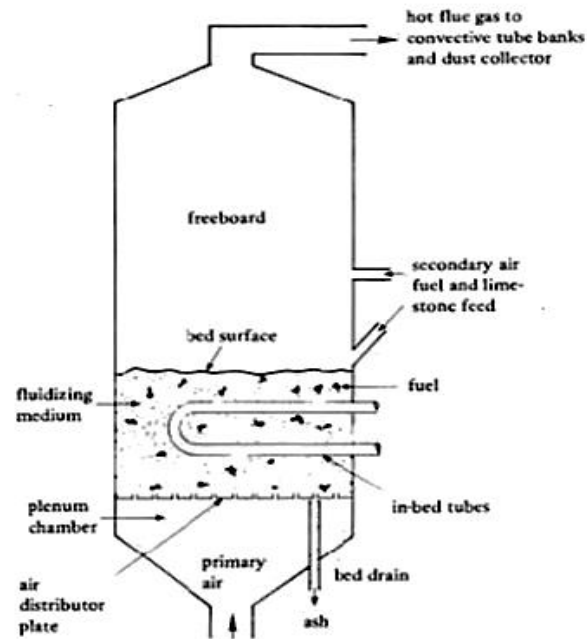


Figure 6.7: Conventional or Bubbling FBC showing components of FBC

6.3 Advantages of FBC Boilers

The criteria that an industrial boiler user applies to select a boiler are: fuel flexibility, operational reliability, environmental acceptability, and economic viability. On each of this criteria FBC boilers have advantage over conventional boilers as described below.

6.3.1 Fuel flexibility:

Most FBC boilers can practically burn all combustible material.

The high thermal inertia and latent heat stored in the bed material allow newly added fuel to ignite quickly and evenly. Wet or low-quality fuels can also be burned efficiently. However, the degree to ease of combustibility varies. The fuels that can be used in FBC along with the ease of usage is shown in figure 6.8.

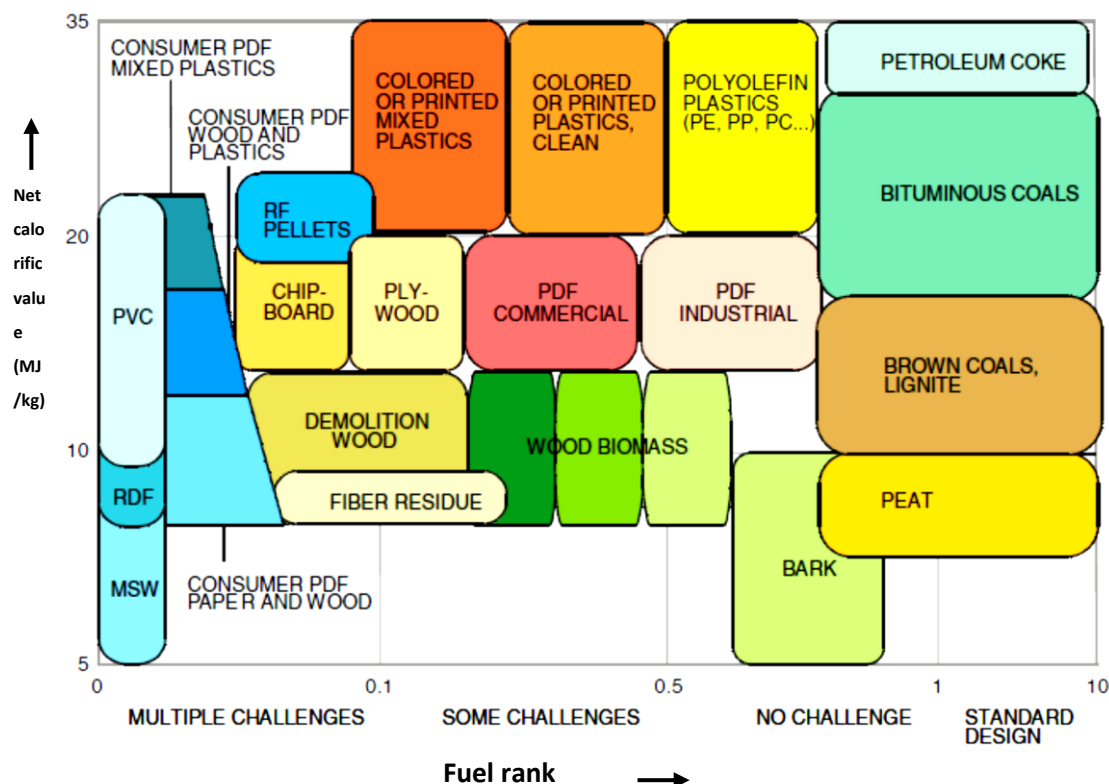


Figure 6.8: Fuels for FBC boiler and their Ease of Use

6.3.2 Operational Reliability

A boiler's operational reliability depends on many factors namely, the auxiliary equipment that pre-treats the fuel (e.g., crushing, screening, feeding); the boiler feed water treatment unit that prepares the water to meet boiler requirements; and the systems that handle combustion flue gas and refuse.

FBC are more reliable than conventional boilers due to following reasons.

- Non usage of pneumatic feeding system
- Operation at lower and more uniform temperature than conventional boilers. Because of the turbulent mixing and the efficient transfer of heat, temperatures within the fluidized bed are uniform which minimizes hot spots. These lower temperatures are below the melting points of most ashes which avoids the slagging and fouling of heat transfer surfaces with melted ash, one of the major problems encountered in solid-fuel fired boilers.
- Having no moving parts that need continuous and frequent maintenance.

6.3.3 Environmental Acceptability

Fluidized bed combustion is more environmentally friendly as it suppresses sulphur dioxide at the time of combustion rather than removing it from flue gases later with expensive and sometimes difficult-to-operate, post-combustive ("scrubbing") devices. By virtue of low combustion temperature, the FBC boiler exhibits attractive sulphur retention characteristics and low nitrogen oxides emission thus enabling a unit to meet the Bangladesh boiler emissions norms as given in table 6.1 in cost effective terms.

Table 6.1: Standards for Gaseous emissions for Boiler of Industrial Unit

S. No.	Parameters	Standards (mg/Nm ³)
Power plant		
1.	Particulate matter	
a.	Capacity ≥200 MW	150
b.	Capacity <200 MW	350
2.	Oxides of nitrogen for Gas fuel based power plant	
a.	≥ 500 MW	50 ppm
b.	200 – 500 MW	40 ppm
	< 200 MW	30 ppm
Industrial Boiler		
1.	Soot and particulate (fuel based)	
a.	Coal	500
b.	Gas	100
c.	Oil	300
2.	Oxides of Nitrogen (fuel based)	
a.	Coal	600
b.	Gas	150
c.	Oil	300
Stack height for Power and Industrial boiler		
a.	Steam per hour upto 15 tons	11
b.	Steam per hour more than 15 tons	14Q ^{0.3}
Where, Q = Emission of sulphur dioxide in kg/hr.		
Boiler using bagasse		
1.	Particulate matter	
a.	Step grade	250
b.	Pulsating	500
c.	Horse shoe spreader stocker	800

6.3.4 Economic Viability

The unique feature of FBC to burn inexpensive, low-grade, and high sulphur coals indicate a favourable cost differential in using FBC.

As they yield a rate of heat transfer five to ten times more efficient than the rate of heat transfer achieved through conventional coal-firing boilers it leads to reducing the size of boiler substantially, thus reducing costs

Table 6.2: Summary of Advantages and Disadvantages of FBC Boilers

Advantages	Disadvantages
- Fuel flexibility - In situ SO₂ removal - Low NO_x emission - Good system availability - No slagging - Low corrosion rate - Easy sizing of fuel	- Higher power of air fan - Larger cross-section of a furnace - Higher surface loss of heat - Higher carbon-in-ash level - Higher erosion rate

The criteria for considering FBC boilers is given in Figure 6.9.

Site specific variables				Operating variables		Design variables		Operating effectiveness		Economics
Emission Requirements Fuel availability - Type - Quality - Quantity Site specific components in case of: - Repower - Retrofit - Add-on - Conversion Application: - Combined Heat and Power - Power generation - Process/space heating	→	Choice of Technology	→	- Fuel used - Sulphur absorbent - NOx control - Bed temperature - Pressure - Gas velocity - Excess air - Particle size - Particle flow - Bed height - Steam parameters	→	- Furnace configuration - Arrangement of boiler functions: - Economizer - Super-heater - Regenerator - Solids removal - Heat exchanger (for solids) - Heat transfer surface - Tube size - Arrangement - Orientation - Air distribution - Location of draft fans - Primary air - Secondary air - Solids handling - Working fluid cycle (e.g. once through) - Sulphur absorbent regenerator - Refractory - Fuel preparation - Fuel feeding - Location - Number of points	→	- Pollution control - Combustion efficiency - Sorbent utilisation - Fluidisation - Heat Transfer - Elutriation - Attrition - Corrosion - Erosion - Agglomeration ash - Control - Turndown - System efficiency - Thermal - Electrical - Solids distribution - Air distribution - Particle diffusion - Reliability - Pressure drop - Heat release	→	- Tubing and fabrication - Structures - Controls - Auxiliaries - Water circulation - Maintenance - Steam headers - Construction time - Solids preparation and distribution - Air preparation and distribution

Figure 6.9: Overview of Variables influencing economic and technological performance

6.4 Types of Fluidized Bed Combustion Boilers

There are three variants of FBC technology.

- The bubbling fluidized bed (BFB) was the first version of FBC technology also called Atmospheric Classic Fluidised Bed Combustion System (AFBC). BFB technology is well suited for utilisation of 'difficult' fuels such as high moisture fuels (e.g. wastes and sludge's), high-ash fuels (e.g. some types of municipal solid waste and refuse-derived fuel) and low volatile fuels (including anthracite, culm and petroleum coke) as well as for smaller industrial applications.
- The circulating fluidized bed (CFB) also called Atmospheric Circulating (fast) Fluidised Bed Combustion system (CFBC) is the second variant and is derived from the BFB technology and surpasses its predecessor in terms of sulphur removal, efficiency and scale. The basic difference between BFB and its successor CFB is the fluidisation velocity, which is higher for CFB compared to BFB.
- The third variant is a hybrid type of the BFB and CFB and is called Pressurised Fluidised Bed Combustion System (PFBC). It was developed to combine the advantages of both BFB and CFB and thus found its application to be in medium-scaled (industrial) capacity range.

6.4.1 AFBC / Bubbling Bed

In this type of FBC coal is crushed to a size of 1 – 10 mm depending on the rank of coal, type of fuel feeding and fed to the combustion chamber. The atmospheric air, which acts as both the fluidization air and combustion air, is delivered at a pressure, and flows through the bed after being preheated by the exhaust flue gases. The in-bed tubes carrying water generally act as the evaporator.

Fluidized bed combustion is to be done in a relatively narrow temperature range within which the bed must be operated. With coal, there is risk of clinker formation in the bed if the temperature exceeds 950°C and combustion efficiency declines below 800°C. For efficient sulphur retention the temperature should be in the range of 800 - 850° C.

The combustion gases pass over the super heater sections of the boiler, flow past the economizer, the dust collectors and the air pre heaters before being exhausted to atmosphere. Almost all atmospheric bubbling bed boilers (AFBC) use the in-bed evaporator tubes for extracting the heat from the bed to maintain the bed temperature. Typical fluidized bed combustors of this type are shown in Figures 6.10 and 6.11.

The bubbling bed has heat transfer tubes in the bed of limestone, sand and fuel. The velocity of fluidizing air is in the range of 1.2 to 3.7 m/sec. About 2 to 4 Kgs of solids are recycled per kg of fuel burned.

The bed depth is usually 0.9 m to 1.5 feet deep and the pressure drop averages about 1 inch of water per inch of bed depth. The bulk of the bed consists of limestone, sand, ash, or other material and a small amount of fuel. The rate at which air is blown through the bed determines the amount of fuel that can be combusted.

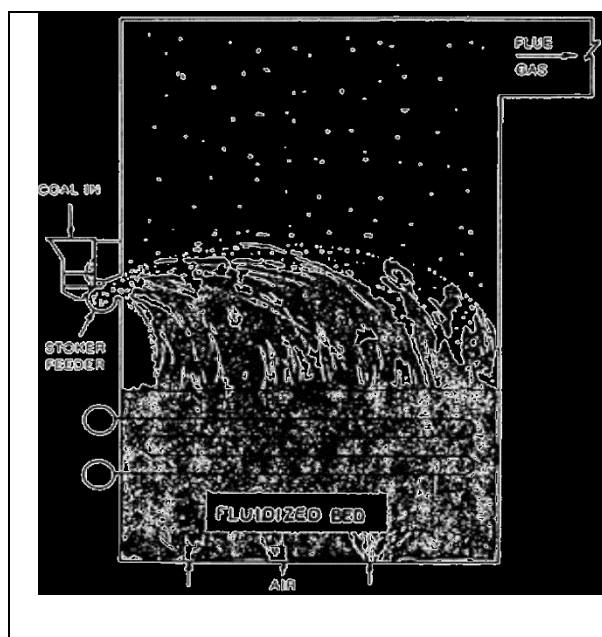


Figure 6.10: Bubbling bed boiler-1

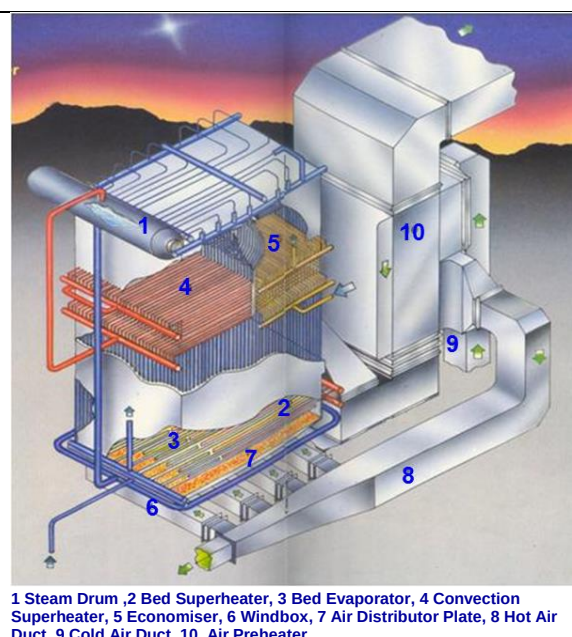


Figure 6.11: Bubbling bed boiler-2

6.4.2 Circulating Fluidised Bed Combustion (CFBC)

This CFB technology utilizes the fluidized bed principle in which crushed (6 –12 mm size) fuel and limestone are injected into the furnace or combustor. The particles are suspended in a stream of upwardly flowing air (60-70% of the total air), which enters the bottom of the furnace through air distribution nozzles. The balance of combustion air is admitted above the bottom of the furnace as secondary air. While combustion takes place at 840-900°C, the fine particles (<450 microns) are elutriated out of the furnace with flue gas velocity of 4-6 m/s. The particles are then collected by the solids separators and circulated back into the furnace as shown in Figure 6.12.

The particles circulation provides efficient heat transfer to the furnace walls and longer residence time for carbon and limestone utilization. The controlling parameters in the CFB combustion process are temperature, residence time and turbulence.

In a circulating system the bed parameters are so maintained as to promote solids elutriation from the bed. They are lifted in a relatively dilute phase in a solids raiser, and a down-comer with a cyclone provides a return path for the solids. There are no steam generating tubes immersed in the bed. Generation and super heating of steam takes place in the convection section, water walls, at the exit of the riser.

CFBC boilers are generally claimed to be more economical than AFBC boilers for industrial application requiring more than 75 – 100 T/hr of steam. For large units, the taller furnace characteristics of CFBC boiler offers better space utilization, greater fuel particle and sorbent residence time for efficient combustion and SO₂ capture, and easier application of staged combustion techniques for NO_x control than AFBC generators.

The circulating bed is designed to move solids out of the furnace area and to achieve most of the heat transfer outside the combustion zone. Some circulating bed units even have external heat exchanges. The fluidizing velocity in circulating beds ranges from 3.7 to 9 m/sec and solid recycle is 50 to 100 kg per kg of fuel burnt.

Furnace temperature is roughly the same in both AFBC and CFBC, but the circulating bed is said to achieve better calcium to sulphur utilization – 1.5 to 1 vs. 3.2 to 1 for the bubbling bed. CFBC requires mechanical cyclones to capture and recycle the bed material and the requirement of a tall boiler.

A CFB could be good choice if the following conditions are met.

- Capacity of boiler is large to medium
- Sulphur emission and NO_x control is important
- The boiler is required to fire low grade fuel or fuel with fluctuating quality.

Major performance features of the circulating bed system are as follows:

- It has a high processing capacity because of the high gas velocity through the system.
- The temperature of about 870°C is reasonably constant throughout the process because of the high turbulence and circulation of solids. The low combustion temperature also results in minimal NO_x formation.
- Sulfur present in the fuel is retained in the circulating solids in the form of calcium sulphate is removed in solid form. The use of limestone or dolomite sorbents allows a higher sulfur retention rate.
- The combustion air is supplied at 1.5 to 2 psig rather than 3-5 psig as required by bubbling bed combustors.
- It has high combustion efficiency.
- It has a better turndown ratio than bubbling bed systems.
- In a bubbling bed system, the surface generally is perpendicular to the flow.

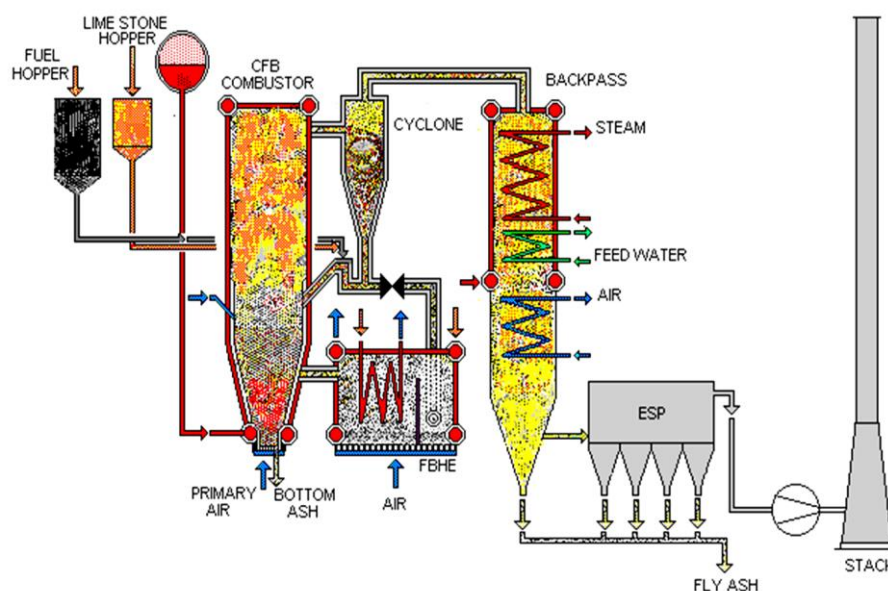


Figure 6.12: Circulating bed boiler design

Table 6.3: Comparison of BFBC and CFBC

Parameter	Units	BFBC	CFBC
Combustion Temperature	°C	760 -870	800 - 900
Fuel particle size	mm	0 - 50	0 - 25
Fluidization Velocities	m/s	1 - 3	0.3-0.5
Solids Circulation		No	Yes
Particle Concentration		High in bottom, low in free board	Gradually decreases with furnace height
Limestone (a) particle size	mm	0.3 - 0.5	0.1 - 0.2
Average steam parameters			
Steam flow range	Kg/s	36 (13 - 139)	60 (12 - 360)
Steam temperature range	°C	466 (150 - 543)	506 (180 - 580)
Steam Pressure range	bar	72 (10 - 160)	103 (10 - 275)
Size	T/hr	All sizes	45-680
Combustion Efficiency	%		2 - 3 % Better than BFBC

Parameter	Units	BFBC	CFBC
Sorbent use		~100% more than CFBC	
Bed Area		2.5 times of CFBC	
Fuel Feed		Over-bed/Under-bed	In-bed
Heat recovery		In-bed tubes	No in-bed tubes
Boiler controls		Conventional	Conventional
Material handling		Conventional	Conventional
Start-up	Hrs.	4	8
O & M			Lower than BFBC
Plant power Auxiliary			Similar if BFBC is over-bed and more if BFBC is under-bed feed system
(a) : Applicable in case when limestone is used for in-bed sulphur removal.			
Source:			
Development of fluidized bed combustion—An overview of trends, performance and cost Joris Koornneef , Martin Junginger, Andre´ Faaij, in Progress in Energy and Combustion Science 33 (2007) 19–55			
Comparison of Bubbling and Circulating Fluidized Bed Industrial Steam Generation by R N Gaglia and A Hall in Proceedings of the 1987 international Conference on FBC			

6.4.3 Pressurized Fluid Bed Combustion

Pressurised Fluidized Bed Combustion (PFBC) is a variation of fluid bed technology that is meant for large scale coal burning applications. In PFBC, the bed vessel is operated at pressure upto 16 ata.

The off-gas from the fluidized bed combustor drives the gas turbine. The steam turbine is driven by steam raised in tubes immersed in the fluidized bed. The condensate from the steam turbine is pre-heated using waste heat from gas turbine exhaust and is then taken as feed water for steam generation.

The PFBC system can be used for cogeneration or combined cycle power generation. By combining the gas and steam turbines in this way, electricity is generated more efficiently than in conventional system. The overall conversion efficiency is higher by 5% to 8%. (Refer Figure 6.13).

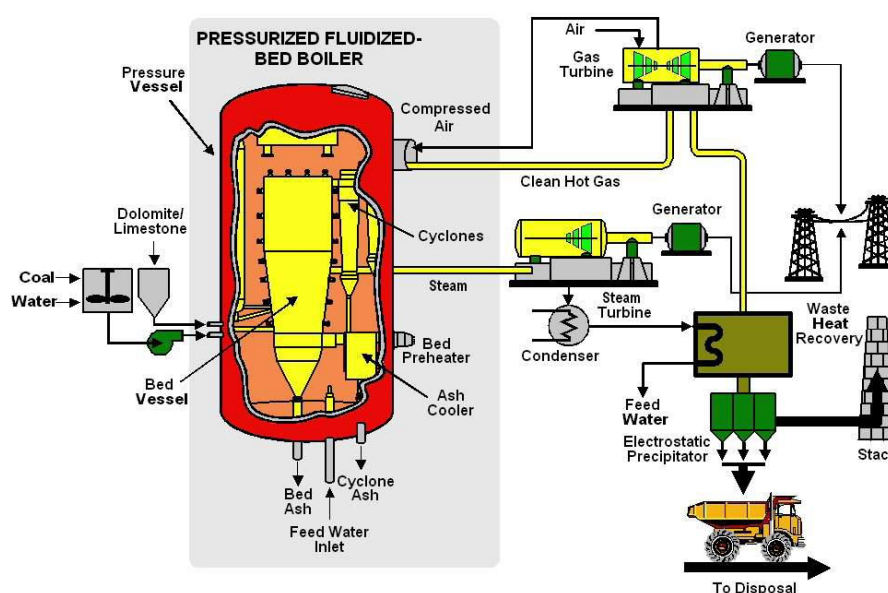


Figure 6.13: PFBC Boiler for Cogeneration

At elevated pressure, the potential reduction in boiler size is considerable due to increased amount of combustion in pressurized mode and high heat flux through in-bed tubes. A comparison of size of a typical 250 MW PFBC boiler versus conventional pulverized fuel-fired boiler is shown in the Figure 6.14.

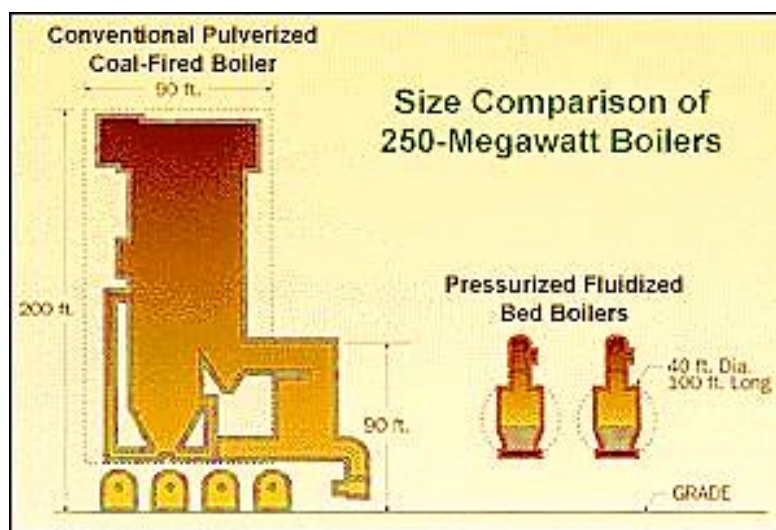


Figure 6.14: Comparison of PFBC boiler versus pulverized fuel boiler

6.5 Retrofitting of FBC Systems to Conventional Boilers

Retrofitting fluidized bed coal fired combustion systems to conventional boilers has been carried out successfully in many countries. The important aspects to be considered in retrofit projects are:

- Water/steam circulation design
- Furnace bottom-grate clearance
- Type of particulate control device
- Fan capacity
- Availability of space.

Retrofitting of a fluidized bed combustor to a conventional stoker fired water tube boiler may involve:

- The replacement of grate by a distributor plate with short stand pipes for admitting air from the wind box located under neath.
- Installation of stand pipes to remove ash from the bed.
- Provision of horizontal hair pin tubes in the bed with a pump for forced circulation from the boiler drum.
- Modification of crusher to size the coal/limestone mixture for pneumatic under-bed injection of the mixture.

Conversion of a conventional coal fired system to a fluidized bed combustion system can be accomplished without effecting major changes, after making a cost-benefit analysis. Oil fired boilers can also be converted to coal fired fluidized bed combustion systems. However, it has to be examined on a case to case basis.

7. Cogeneration

7.1 Introduction– Definition and Need

In conventional power plant when steam or gas expands through a turbine, nearly 60 to 70% of the input energy escapes with the exhaust steam or gas yielding only 30-40% efficiency. Also further losses of around 10-15% are associated with the transmission and distribution of electricity in the electrical grid. These losses are greatest when electricity is delivered to the smallest consumers.

If this energy in the exhaust steam or gas is utilized for meeting the process heat requirements, the efficiency of utilization of the fuel will increase and corresponding GHG emissions will reduce. Such an application, where the electrical power and process heat requirements are met from the fuel, is termed as “Cogeneration” or combined heat and power (CHP). The concept of CHP is illustrated in figure 7.1. Since, most of the industries need both heat and electrical energy, cogeneration can be a sensible investment for industries.

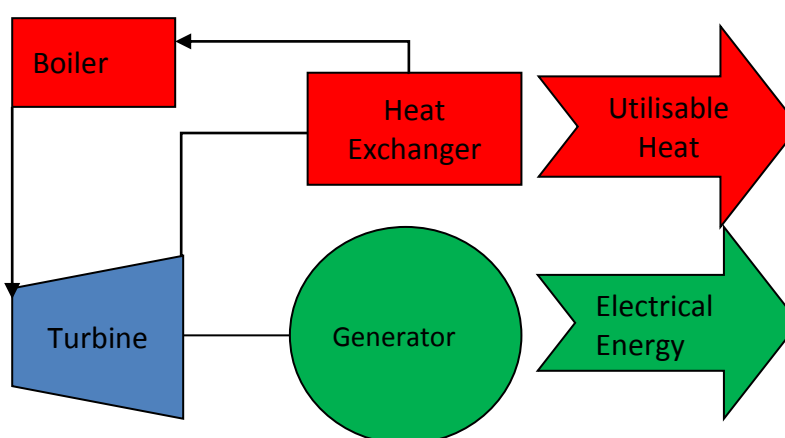
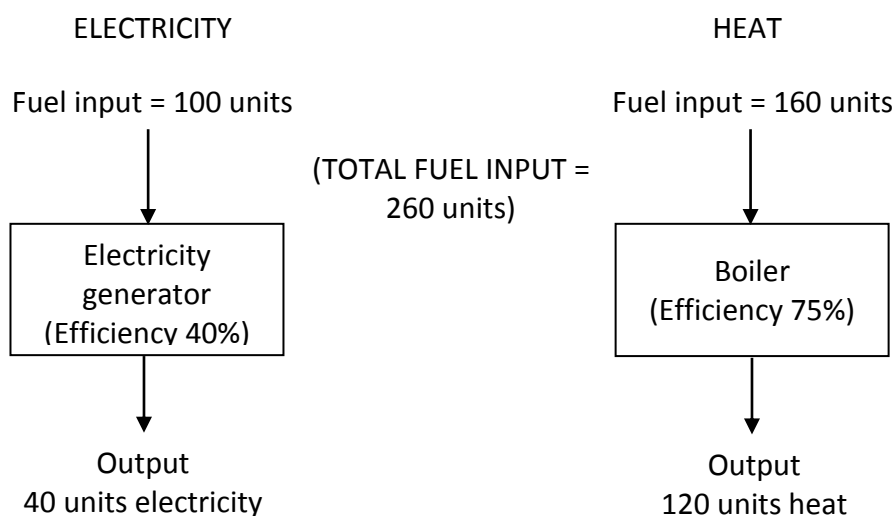


Figure 7.1: Cogeneration System

In cogeneration system efficiencies can go upto 90% and above providing energy savings ranging between 15-40% when compared against the supply of electricity and heat from conventional power stations and boilers. Since, electricity generated by cogeneration plant is normally used locally the transmission and distribution losses are negligible.

As an illustrative case, a plant needs 40 units of electric power and 120 units of thermal energy for its operation. Initially the plant met its requirement by having separate source for the electric power and thermal energy. In this process the total input required is 260 units. After installing a cogeneration system to meet both the loads, the plant is able to increase the overall efficiency of the system and bring down the input from 260 units to 200 units. Figure 7.2 gives comparison between Separate Heat and Power and Cogeneration System.

Case A: Separate Heat and Power



Case B: Combined Heat and Power

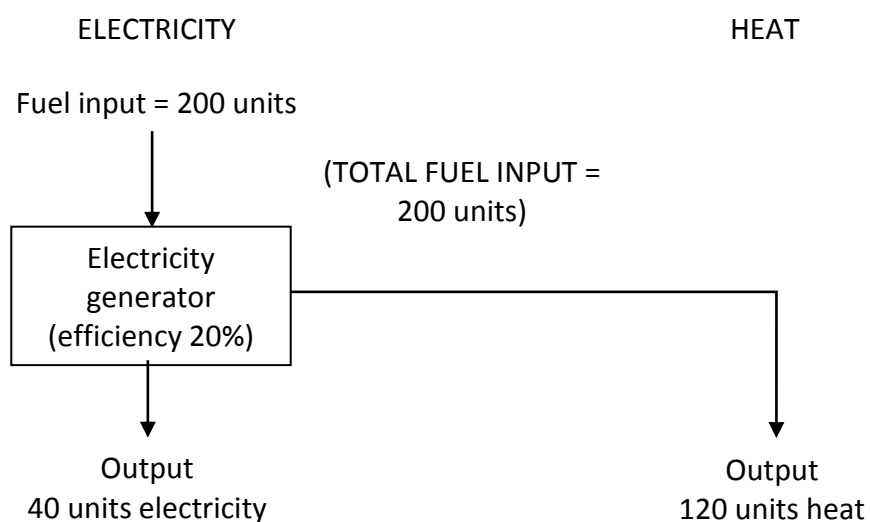


Figure 7.2: Comparison between energy inputs without and with cogeneration

In a cogeneration system, if less electricity is generated than needed, it will be necessary to buy extra. However, when the scheme is sized according to the heat demand, normally, more electricity than needed is generated. The surplus electricity can be sold to the grid. It can also be supplied to another customer via the distribution system, which is called the wheeling of power. As a rough guide, Cogeneration is likely to be suitable if there is constant heat demand for atleast 4,500 hours per year.

7.2 Classification of Cogeneration Systems

There are two main types of cogeneration concepts: “Topping Cycle” plants, and “Bottoming Cycle” plants. A topping cycle plant generates electricity or mechanical power first whereas a bottoming cycle plant generates heat first.

7.2.1 Topping Cycle

There are four types of topping cycle cogeneration systems. They are:

Topping cycle cogeneration systems are of two types:

- 1) Fuel can be burned directly in either a gas turbine or a diesel engine to produce electrical or mechanical power and the exhaust is used to provide process heat or process steam. This is called a combined- cycle topping system. The process is shown in figure 7.3.
- 2) Fuel can be burned initially to produce high-pressure steam which is then passed through a steam turbine to produce power, and the exhaust is used as process steam. A gas turbine or diesel engine producing electrical or mechanical power followed by a heat recovery boiler to create steam to drive a secondary steam turbine. This is a steam-turbine topping system.
- 3) A third type employs hot water from an engine jacket cooling system flowing to a heat recovery boiler, where it is converted to process steam and hot water for space heating.
- 4) The fourth type is a gas-turbine topping system. A natural gas turbine drives a generator. The exhaust gas goes to a heat recovery boiler that makes process steam and process heat.

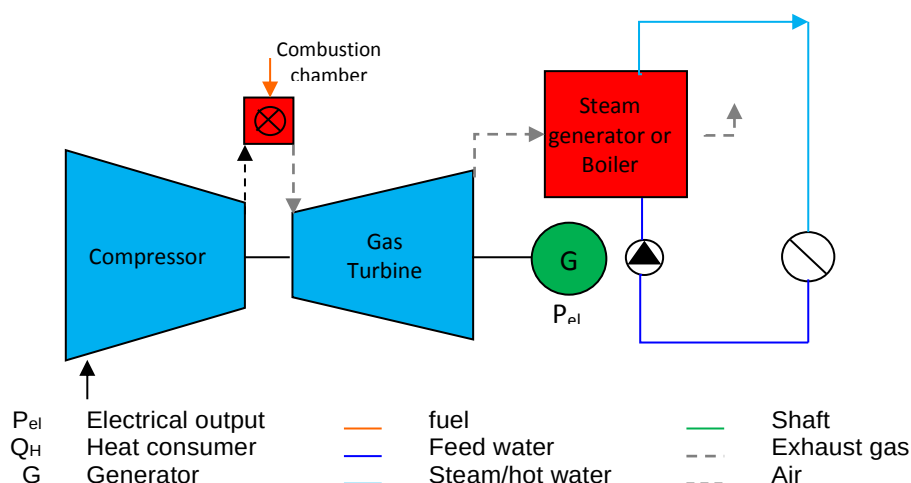


Figure 7.3: Gas turbine topping systems

7.2.2 Bottoming Cycle:

Bottoming cycle plants are much less common than topping cycle plants. These plants exist in heavy industries such as glass or metals manufacturing where very high temperature furnaces are used. The Figure 7.4 illustrates the bottoming cycle where fuel is burnt in a furnace to produce synthetic rutile. The waste gases coming out of the furnace is utilized in a boiler to generate steam, which drives the turbine to produce electricity.

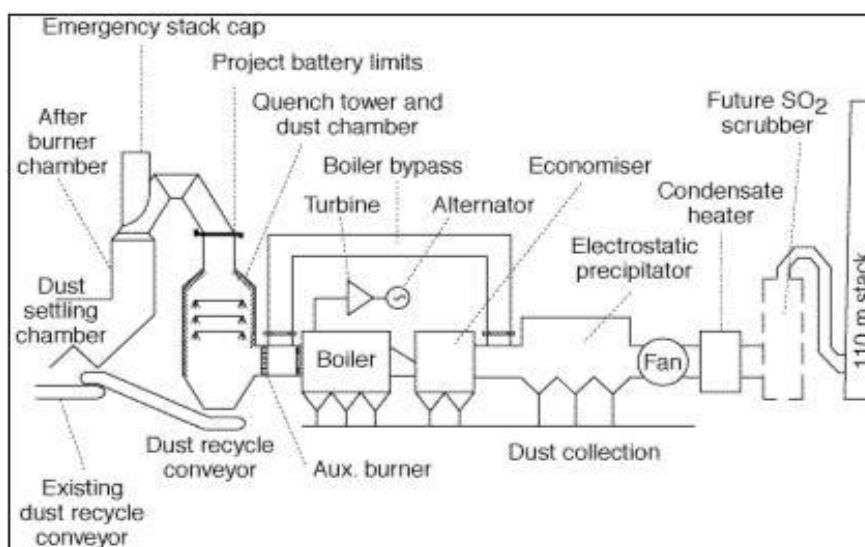


Figure 7.4: Bottoming cycle

7.3 Types of Cogeneration Systems

- Steam turbine
- Gas turbine
- Diesel engine

7.3.1 Steam Turbine

Steam turbines are the most commonly employed prime movers for cogeneration applications. In the steam turbine, high pressure steam generated in a boiler or heat recovery steam generator (HRSG) is expanded to a lower pressure level, converting the thermal energy of high pressure steam to kinetic energy through nozzles and then to mechanical power through rotating blades. Boiler fuels can include fossil fuels such as coal, oil and natural gas or renewable fuels like wood or municipal waste.

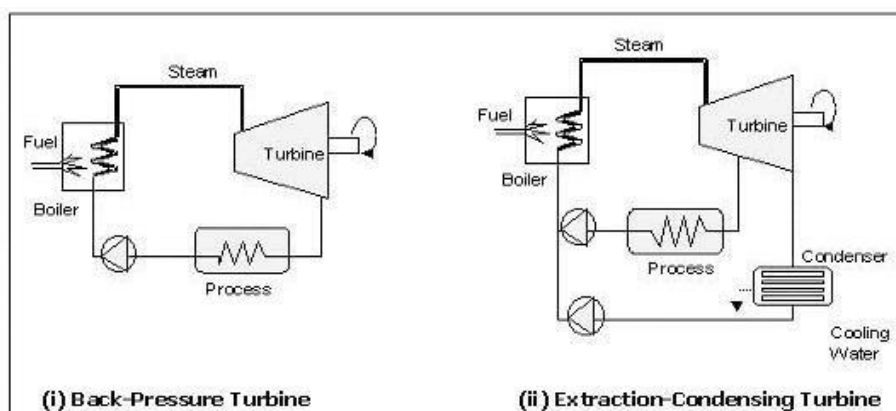


Figure 7.5: Steam turbine cogeneration system

The thermodynamic cycle for the steam turbine is the rankine cycle, although a number of different cycles are also used, such as the Reheat, the Regenerative and the combined cycle. The rankine cycle is the basis for conventional power generating stations and consists of a heat source (boiler) that converts water to high- pressure steam. The steam flows through the turbine to produce power and may be wet, dry saturated or superheated.

Depending on the pressure (or temperature) levels at which process steam is required, back-pressure steam turbines can have different configurations. In extraction and double extraction back-pressure turbines, some amount of steam is extracted from the turbine after being expanded to a certain pressure level. The extracted steam meets the heat demands at pressure levels higher than the exhaust pressure of the steam turbine.

The efficiency of a back-pressure steam turbine cogeneration system is the highest. In cases where 100 per cent back-pressure exhaust steam is used, the only inefficiencies are gear drive and electric generator losses, and the inefficiency of steam generation. Therefore, with an efficient boiler, the overall thermal efficiency of the system could reach as much as 90 percent.

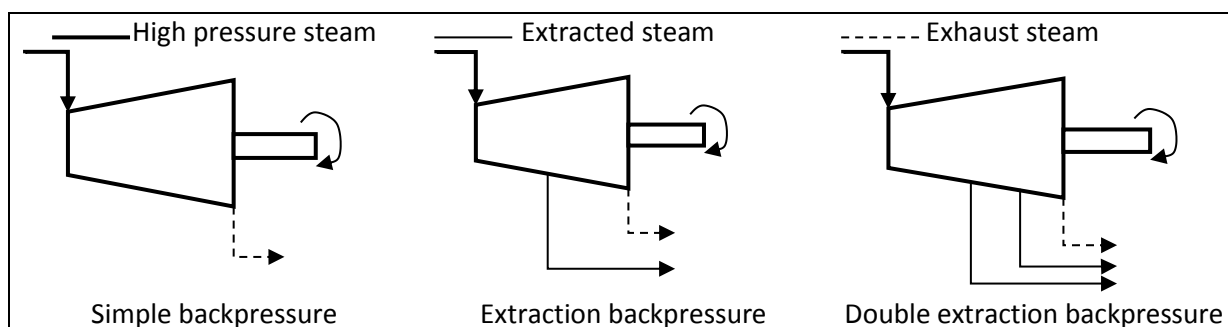


Figure 7.6: Configurations for back pressure steam turbines

Back-Pressure turbine: In this type steam enters the turbine chamber at **High Pressure** and expands to **Low or Medium Pressure**. Enthalpy difference is used for generating power /work.

Total Condensing turbine: In this type, steam entering at High / Medium Pressure condenses in a surface condenser and work is done till it reaches the Condensing pressure (vacuum).

Extraction cum Condensing steam turbine: In this high Pressure steam enters the turbine and passes out from the turbine chamber in stages. The Figure 7.6 shows a two stage extraction cum condensing turbine. In this MP steam and LP steam pass out to meet the process needs. Balance quantity condenses in the surface condenser. The Energy difference is used for generating Power. This configuration meets the heat-power requirement of the process.

The extraction condensing turbines: These turbines have higher power to heat ratio in comparison with back-pressure turbines. Although condensing systems need more auxiliary equipment such as the condenser and cooling towers, better matching of electrical power and heat demand can be obtained where electricity demand is much higher than the steam demand and the load patterns are highly fluctuating.

The over all thermal efficiency of an extraction condensing turbine cogeneration system is lower than that of back pressure turbine system, basically because the exhaust heat cannot be utilized (it is normally lost in the cooling water circuit). However, extraction condensing cogeneration systems have higher electricity generation efficiencies.

7.3.2 Gas Turbine

In gas turbines fuel is burnt in a pressurized combustion chamber using combustion air supplied by a compressor. These hot gases expand through the blades on the turbine rotor causing them to move generating mechanical energy.

In conventional Gas turbine, gases enter the turbine at 900 to 1000°C and leave at 400 to 500 °C. Residual energy in the form of hot exhaust gases can be used to generate wholly or partly,

the thermal (steam) demand of the site.

The available mechanical energy can be applied in the following ways:

- to produce electricity with a generator (most applications);
- to drive pumps, compressors, blowers, etc.

A gas turbine operates under exacting conditions of high speed and high temperature. The hot gases supplied to it must be free of particulates which would erode the blades and contain no more than minimal amounts of contaminants, which would cause corrosion under operating conditions. High-premium fuels are therefore most often used, particularly natural gas. Distillate oils such as gas oil LPGs and Naphtha are suitable.

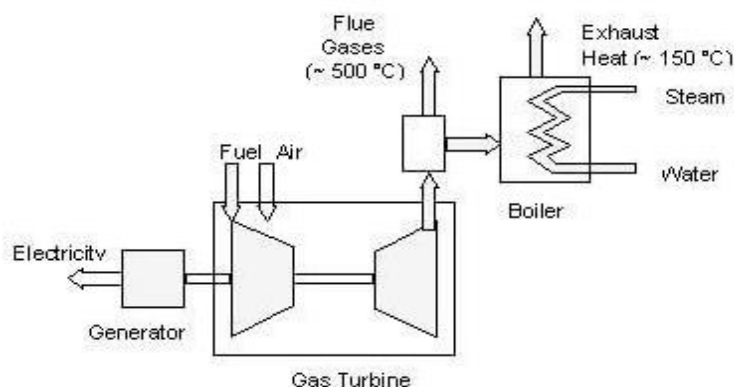


Figure 7.7: Gas turbine

7.3.2.1 Gas Turbine Efficiency

Turbine Efficiency is the ratio of actual work output of the turbine to the net input energy supplied in the form of fuel. For standalone Gas Turbines, without any heat recovery system the efficiency will be as low as 35 to 40%. This is attributed to the blade efficiency of the rotor, leakage through clearance spaces, friction, irreversible turbulence etc.

7.3.2.2 Increasing Overall Efficiency

Since Exhaust gas from the Gas Turbine is high, it is possible to recover energy from the hot gas by a Heat Recovery Steam Generator and use the steam for process.

7.3.2.3 Net Turbine Efficiency

Above efficiency figures did not include the energy consumed by air compressors, fuel pump and other auxiliaries.

Air compressor alone consumes about 50 to 60 % of energy generated by the turbine. Hence net turbine efficiency, which is the actual energy output available will be less than what has been calculated. In most Gas Turbine plants, air compressor is an integral part of Turbine plant.

7.3.3 Diesel Engine Systems

This system provides process heat or steam from engine exhaust. The engine jacket cooling water heat exchanger and lube oil cooler may also be used to provide hot water or hot air. There are, however, limited applications for this. As these engines can use only fuels like HSD, distillate, residual oils, natural gas, LPG etc. and as they are not economically better

than steam/gas turbine, their use is not widespread for co-generation. One more reason for this is the engine maintenance requirement.

7.4 Methods for Calculating CHP System Efficiency

Two efficiency metrics namely Total system efficiency and Effective electric efficiency are used to compare CHP systems with SHP systems:

Total system efficiency refers to the sum of the useful power output (in MWh expressed in Btu/hr) and useful thermal outputs (in Btu/hr) divided by the total fuel input (in Btu/hr) and is the more commonly cited efficiency metric.

Effective electric efficiency refers to the electricity output divided by the additional fuel the CHP system uses over and above what would have been used by a conventional system to meet the facility's thermal energy load.

Both efficiency metrics consider all the outputs of CHP systems and reflect the benefits of CHP. Since each metric measures a different performance characteristic, the purpose and calculated value of each type of efficiency metric differs. For example, the total system efficiency is typically most appropriate for comparing CHP system energy efficiency with the efficiency of a site's SHP options. The effective electric efficiency is typically used to compare the CHP system with conventional electricity production (i.e., the grid).

In general, a CHP system's total system efficiency differs from its effective electric efficiency by 5% to 15%.

7.5 Typical Cogeneration Performance Parameters

The following Table 7.1 gives typical Cogeneration Performance Parameters for different Cogeneration Packages giving heat rate, overall efficiencies etc.

Table 7.1: Typical Cogeneration Performance Parameters

Prime Mover in Cogen. Package	Nominal Range (Electrical)	Electrical Generation to Heat Rate (kCal / kWh)	Efficiencies, %		
			Electrical Conversion	Thermal Recovery	Overall Cogeneration
Smaller Reciprocating Engines	10 – 500 kW	2650 - 6300	20-32	50	74-82
Larger Reciprocating Engines	500 – 3000 kW	2400 - 3275	26-36	50	76-86
Diesel Engines	10-3000 kW	2770 - 3775	23-38	50	73-88
Smaller Gas Turbines	800-10000 kW	2770-3525	24-31	50	74-81
Larger Gas Turbines	10-20 MW	2770-3275	26-31	50	78-81
Steam Turbines	10-100 MW	2520-5040	17-34	-	-

Note: Adapted from Cogeneration Handbook California Energy Commission, 1982

7.6 Heat: Power Ratio

Cogeneration is likely to be most attractive when the demand for both steam and power is balanced i.e. consistent with the range of steam (Heat) to power output ratios that can be obtained from a suitable cogeneration plant.

Heat-to-power ratio defined as the ratio of thermal energy to electricity required by the energy consuming facility and expressed in different units such as Btu/kWh, kcal/kWh, kW/kW, etc. It is

one of the most important technical parameters influencing the selection of the type of cogeneration system. The proportions of heat and power needed (heat to power ratio) vary from site to site, so the type of plant selected should match demands as closely as possible. The plant may therefore be set up to supply part or all of the site heat and electricity loads, or an excess of either may be exported if a suitable customer is available.

Heat-to-power ratios of different cogeneration systems and for certain energy intensive industries are shown in Table 7.2 & 7.3.

Table 7.2: Heat-to-power ratios & key parameters of cogeneration systems

Cogeneration System	Heat-to- Power ratio (KW/KW)	Power Output (as % of fuel input)	Overall efficiency %
Back-pressure steam turbine	4.0-14.3	14-28	84-92
Extraction-condensing steam turbine	2.0-10	22-40	60-80
Gas turbine	1.3-2.0	24-35	70-85
Combined Cycle	1.0-1.7	34-40	69-83
Reciprocating Engine	1.1-2.5	33-53	75-85

Table 7.3: Typical Heat: Power ratios for certain energy intensive industries

Industry	Minimum	Maximum	Average
Breweries	1.1	4.5	3.1
Pharmaceuticals	1.5	2.5	2.0
Fertilizer	0.8	3.0	2.0
Food	0.8	2.5	1.2
Paper	1.5	2.5	1.9

7.7 Factors for selection of cogeneration system

Following factors should be given due consideration in selecting the most appropriate cogeneration system for a particular industry.

- Normal as well as maximum/minimum power load and steam load in the plant, and duration for which the process can tolerate without these utilities, i.e. criticality and essentiality of inputs.
- What is more critical - whether power or steam, to decide about emergency back-up availability of power or steam.
- Anticipated fluctuations in power and steam load and pattern of fluctuation, sudden rise and fall in demand with their time duration and response time required to meet the same.
- Under normal process conditions, the step by step rate of increase in drawl of power and steam as the process picks up - whether the rise in demand of one utility is rapid than the other, same or vice-versa.
- Type of fuel available - whether clean fuel like natural gas, naphtha or high speed diesel or high ash bearing fuels like furnace oil, LSHS, etc or worst fuels like coal, lignite, etc., long term availability of fuels and fuel pricing.
- Commercial availability of various system alternatives, life span of various systems and corresponding outlay for maintenance.
- In general, simultaneous demands for heat and power must be present for at least 4,500 h/year, although there are applications where CHP systems may be cost effective with fewer hours. For example, when electricity rates are high or when the local power

- provider offers incentives, this operating period could be as low as 2,200 h/year.
- Power-to-heat ratio for the plant should not fluctuate more than 10%.
 - Influence exerted by local conditions at plant site, i.e. space available, soil conditions, raw water availability, infrastructure and environment.
 - Project completion time.
 - Project cost and long term benefits.

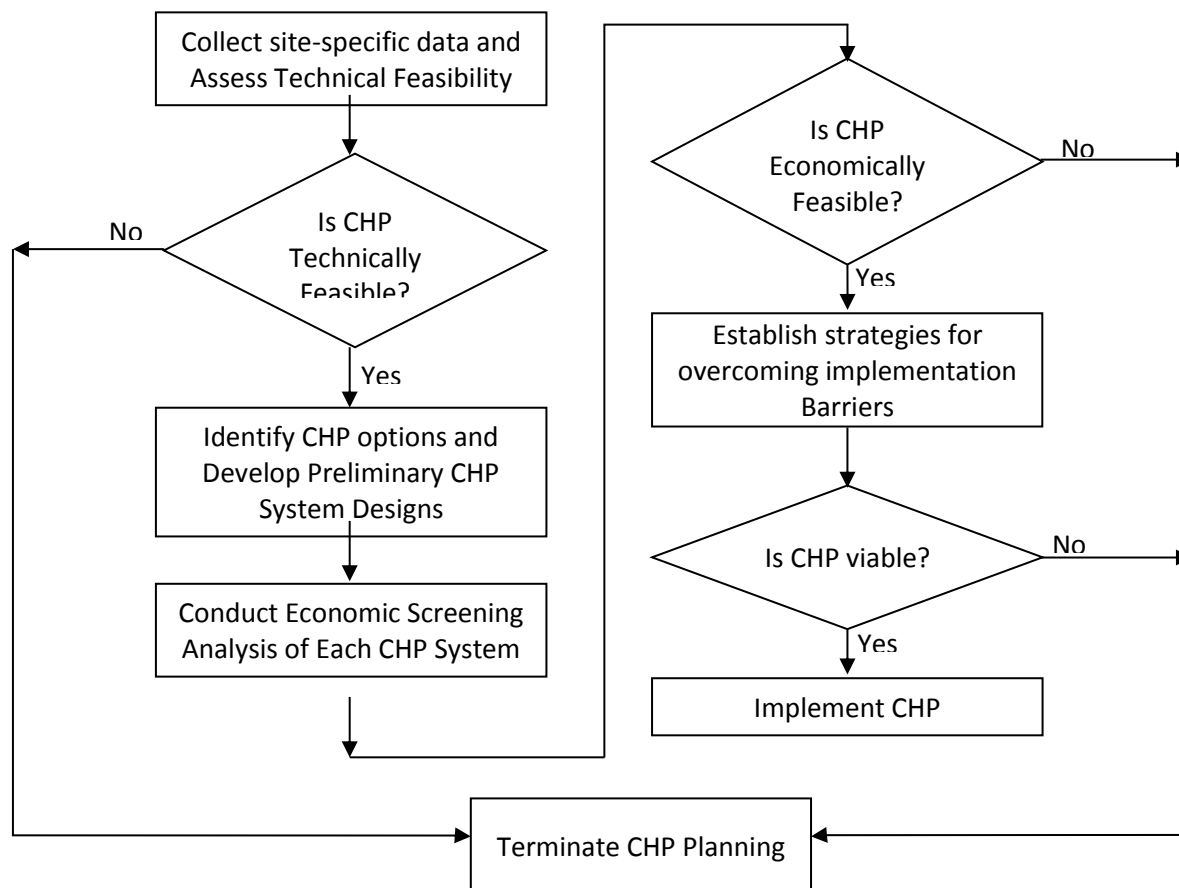


Figure 7.8: Framework for Evaluating CHP viability

7.8 Operating Strategies for Cogeneration Plant

For cogeneration plant there are three main operating regimes:

- The unit is operated to provide base load electrical and thermal output. Any shortfall is supplemented with electricity from external public/private utility and heat from stand-by boilers or boost (thermic fluid) heaters;
- The unit is operated to provide electricity in excess of the site's requirements, for export, whilst all the thermal output is used on site;
- The unit is operated to provide electricity for site, with or without export, and the heat produced is used on site with the surplus being exported to off-site customers.

Table 7.4: Characteristics of Prime Movers for CHP Applications ^a

Prime Mover Characteristic	Steam Turbine	Gas turbine	Micro turbine	Reciprocating Engine	
				Compression Ignition	Spark Ignition
Capacity, MW	0.05 to > 250	0.5 to 250	0.03-0.35	0.03 to 4	0.05 to 5
Power-to-heat ratio	0.05 to 0.2	0.5 to 2	0.4 to 0.7	0.5 to 1	0.5 to 1
Fuels	All types of fuel can be burned to produce steam	Natural gas, bio gas, propane and distillate fuel oil	Natural gas, Waste and sour gases, gasoline, kerosene, diesel and distillate fuel oil	Natural gas, diesel and residual oil	Natural gas, bio gas, propane, land fill gas and gasoline
Installed cost, \$/KW	200 -1000	400 -1800	1300 -2500	900 - 1500	901 - 1500
Maintenance cost, \$/KWh	≤ 0.002	0.003 - 0.01	≤ 0.018	0.005 - 0.015	0.007 - 0.02
Overhaul period, h	> 50000	12000 - 50000	5000 - 40000	25000 - 30000	24000 - 60000
Start-up time	Hours	Minutes	Minutes	Seconds	Seconds
Total CHP efficiency (HHV) ^b	70 - 85 %	70 - 75 %	65 - 75 %	70 - 80 %	70 - 80 %
CHP electrical efficiency (HHV) ^c	20 - 40 %	22 - 36 %	18 - 29 %	27 - 45 %	22 - 40 %
Availability	Nearly 100%	90 - 98 %	90 - 98 %	90 - 95 %	92 - 97 %
Noise	High	High	High	Moderate	High
Service life	30 years or more	30000 - 100000 hrs	40000 - 80000 hrs	15 - 25 years	15 - 25 years
Part-load operation	Good	Poor	Satisfactory	Good	Satisfactory
NOx control options	Unnecessary but may be required as part of	Steam or water injection, lean	Lean premixed combustion, SCR, SNCR	Lean air-fuel mixture, SCR,	Lean air-fuel mixture, staged ignition, catalytic

Prime Mover Characteristic	Steam Turbine	Gas turbine	Micro turbine	Reciprocating Engine	
				Compression Ignition	Spark Ignition
	steam supply system.	premixed combustion, SCR, SNCR and SCONOXTM	and SCONOXTM	SNCR and SCONOXTM	3-way conversion(TWC), SCR, SNCR and SCONOXTM
Preferred uses for recovered heta	Process heat, hot water and low-pressure to high pressure steam	Process heat, hot water and low-pressure to high pressure steam	Process heat, hot water and low-pressure steam	Hot water and low-pressure steam	Hot water and low-pressure steam
Temperature of rejected heat, °F	Varies depending on extraction conditions	500 -1100	400 - 600	180 - 900	180 - 1200
Operating mode	Load-tracking and continuous base-loaded operation	Base-loaded, load-tracking, and peak shaving operations	Base-loaded, load-tracking, and peak shaving operations	Base-loaded, load-tracking, emergency and peak shaving operations	Base-loaded, load-tracking, emergency and peak shaving operations
Potential applications	Topping-cycle, bottoming-cycle, combined-cycle, and trigeneration CHP systems	Topping-cycle, combined-cycle, and trigeneration CHP systems	Topping-cycle, combined-cycle, and trigeneration CHP systems	Topping-cycle, combined-cycle, and trigeneration CHP systems	Topping-cycle, combined-cycle, and trigeneration CHP systems
a Based on CHP systems that operate at least 8000 hrs/year					
b Total CHP efficiency is a measure of (the net electricity generated plus the net heat supplied to the process), divided by the total fuel input					
c CHP electrical efficiency is a function of the net electricity generated, divided by the total fuel input					

Table 7.5: Sources of Information for decision making

Required information	Sources of Information								
	Energy Audit	Utility Company	Fuel Suppliers ^a	Equipment Suppliers	Management	Legal authorities	Air -water quality authority	Special authorities ^b	Financial Institutions
Total thermal loads, magnitude and profile	X								
Total electrical loads, magnitude and profile	X								
Cooling Loads	X								
Major load centers and energy consumers	X								
Anticipated load changers, Mission or Function changes	X								
Waste heat sources	X								
Waste fuel sources	X								
Complimentary off-site loads	X								
Present Electrical Energy Costs and Rate Formats	X	X							
Projected Electrical Energy Rate structure		X							
Policies towards parallel generation		X							
Ownership/Operation policies and preferences		X			X				
Cogenerator rate structure, Standby charges, Reliability Requirements, Payment for Power to Grid		X							
Environmental and Siting Constraint Overview		X							
Tax and Investment Incentives		X				X			
Regulations Related to Cogeneration		X				X			
Present Fuel Costs	X		X						
Projected fuel costs		X	X						
Projected fuel availability		X	X						
Fuel Characteristics and Properties			X						
Performance Data, Design and Off Design Conditions				X					
Fuel Consumption				X					
Fuel Flexibility				X					
Emissions Data and Specifications				X					
Air Emission Regulations				X			X		
Other Emission Regulations				X				X	
Fiscal Policies					X				
Funding Sources					X				X
Cost and Conditions of financing									X
Siting restrictions						X	X	X	

a Oil, Natural gas or Coal

b For example, Zoning, airport, Coastal

Source : Cogeneration Systems- Technical Report by E E Cooper 1980

7.9 Relative Merits of Co-Generation Systems

The following Table 7.6 gives the advantages and disadvantages of various co-generation systems:

Table 7.6: Advantages and disadvantages of various cogeneration systems

Variant	Advantages	Disadvantages
Back-pressure	- High fuel efficiency rating	Little flexibility in design and operation
Steam turbine & fuel firing in boiler	- Simple plant - Well-suited to low quality fuels	- More capital investment - Low fuel efficiency rating - High cooling water demand - More impact on environment - High civil const. cost due to complicated foundations
Gas turbine with waste heat recovery boiler	- Good fuel efficiency - Simple plant - Low civil const. Cost - Less delivery period - Less impact on environment - High flexibility in operation	- Moderate part load efficiency - Limited suitability for low quality fuels
Combined gas & steam turbine with waste heat recovery boiler	- Optimum fuel efficiency rating - Low relative capital cost - Less gestation period - Quick start up & stoppage - Less impact on environment - High flexibility in operation	- Average to moderate part-load efficiency - Limited suitability for low quality fuels
Diesel Engine & waste heat recovery Boiler & cooling water heat exchanger	- Low civil const. Cost due to block foundations & least no. of auxiliaries - High Power efficiency - Better suitability as standby power source	- Low overall efficiency - Limited suitability for low quality fuels - Availability of low temperature steam - Highly maintenance prone.

7.10 Case Study

Economics of a Gas Turbine based Cogeneration System

Alternative I: Gas Turbine based Cogeneration.		
Gas Turbine Parameters	Units	Quantity
Capacity of gas turbine generator	KW	4000
Plant operating hours per annum	hrs/ year	8000
Plant load factor (PLF)	%	90%
Heat rate as per standard given by gas turbine suppliers	KCal/KWH	3049.77
Waste heat boiler parameters- unfired steam output	TPH	10
Steam temperature	°C	200
Steam pressure	Kg/ Sq.cm	8.5
Steam enthalpy	Kcal/Kg	676.44
Fuel used		Natural Gas
Calorific Value - LCV	Kcal/ S Cu.m	9500
Price of gas	BDT/1000 S Cu.m	3000
Capital investment for Cogeneration plant	BDT	1300000
Cost Estimation of Power & Steam from Cogeneration Plant		
Power generated = PLF x Plant Capacity x Operating hrs	KWH/ Year	28800000
Heat input = Power generated x Heat rate given by turbine supplier	Kcal	87833376000
Natural gas(NG) required per annum = Heat input/ LCV of NG	S cu.m	9245618.526
Annual cost of fuel = Gas consumed x price	BDT	27736855.58
Annualised Cost of capital and operation charges	BDT	29863000
Overall cost of power from cogeneration plant (Alternative -I Cost)	BDT	57599855.58
Cost of power	BDT/KWH	1.999994985

Alternative-II Electric Power from State Grid & Steam from Natural Gas (NG) Fired Boiler		
Boiler installed in plant	TPH	10
Cost of electric power from grid	BDT/KWH	3
Capital investment for 10TPH, 8.5 kg/cm ² @ 200°C NG fired fire tube boiler & all auxiliaries	BDT	8000000
Hours of operation	hrs/ year	8000
Cost Estimation of Power & Steam from Grid and Steam from direct Conventional fired boiler		
Cost of power from state grid for 28800000 KWH	BDT/ year	86400000
Fuel cost for steam by separate boiler		
Heat output in form of 10TPH steam per annum = Boiler capacity x steam Enthalpy x Hrs of operation	Kcals/ year	54115200000
Heat input required to generate 10TPH steam per annum @ 90% efficiency	Kcals/ year	60128000000
Natural gas(NG) required per annum = Heat input/ LCV of NG	S cu.m/ year	6329263.158
Annual cost of fuel = Gas consumed x price	BDT	18987789.47
Total cost for alternative II= Cost of grid power + fuel cost for steam	BDT	105387789.5
Alternative -I total cost	BDT	57599855.58
Alternative -II total cost	BDT	105387789.5
Differential cost	BDT	47787933.89

(Note: In case of alternative II, there will be some additional impact on cost of steam due to capital cost required for a separate boiler)

In the above case it can be seen that Alternative I is economical compared to Alternative II.

8. Waste Heat Recovery

8.1 Introduction

Industrial waste heat refers to the heat energy that is generated but not fully utilized in the industrial processes and leaves the boundaries of a plant or building into the surrounding environment. Waste heat is generally associated with waste streams of air, exhaust gases, water, or other liquids. Waste heat losses arise both from equipment inefficiencies and due to equipment and process requirements. These losses can be reduced by improving equipment efficiency and installing waste heat recovery technologies.

Waste heat recovery (WHR) equipment is defined as any mechanical apparatus which usefully recovers thermal energy from process waste streams that are above ambient temperatures. The recovered heat is used to produce heat, generate power and in some cases for cooling applications. The aim of this chapter is to provide an understanding of why, when and how to recover waste heat and will cover the following aspects of WHR.

- Opportunities and benefits of WHR
- factors effecting waste heat recovery
- applications of waste heat
- WHR methods and technologies
- Industry/sector specific applications of WHR technologies
- Formulae for calculating heat losses
- Case examples of WHR implemented

8.2 Opportunities and benefits of WHR

The best waste heat-recovery opportunities are those that have the following characteristics:

- The waste heat supply is constant.
- The need is co-located with the waste heat supply.
- The need is synchronized with the available waste heat.
- The waste heat supply is higher in temperature than the need or
- The need and the waste heat stream temperatures match the capabilities of available heat-pumping equipment.
- The size of the waste heat stream and the need are large enough to justify the custom engineering required.

Benefits of 'waste heat recovery' can be broadly classified in two categories:

8.2.1 Direct Benefits:

Recovery of waste heat has a direct effect on the efficiency of the process. This is reflected by reduction in the utility consumption and process cost.

8.2.2 Indirect Benefits:

a) Reduction in equipment sizes: Waste heat recovery reduces the fuel consumption, which leads to reduction in the flue gas produced. If WHR systems are considered and incorporated at design stage it may result in reduction in equipment sizes of all flue gas handling equipments such

as fans, stacks, ducts, burners, etc. In other modification and retrofit cases possibility exists to reduce the size of equipment.

b) Reduction in auxiliary energy consumption: Reduction in equipment sizes gives additional benefits in the form of reduction in auxiliary energy consumption like electricity for fans, pumps etc.

c) Reduction in pollution: A number of toxic combustible wastes such as carbon monoxide gas, sour gas, carbon black off gases, oil sludge, Acrylonitrile and other plastic chemicals etc., when combusted/burnt in the thermal oxidation or incinerators serves dual purpose of heat recovery and mitigation of the environmental pollution levels.

8.3 Factors affecting waste heat recovery

Before considering waste heat recovery it is important to consider why, when and how to recover this waste heat to gain benefits. The following factors influence the selection of a heat exchanger.

- **Source of the waste heat stream.**

In few cases it is difficult to access and recover heat from unconventional sources such as hot solid product streams (e.g., ingots) and hot equipment surfaces (e.g., sidewalls of primary aluminum cells).

- **Amount of waste heat available**

Once you find suitable waste heat source, it is important to establish that the source is capable of supplying sufficient 'quantity' of heat, and that the heat is of a good enough 'quality' (i.e. temperature) to promote good heat transfer.

- **Characteristics of the waste heat stream**

Essential considerations in making optional choice of waste heat recovery device:

- 1) Temperature of waste heat. (Temperature is a measure of quality of waste heat)
- 2) Flow rate of the fluid
- 3) Chemical composition of waste fluid
- 4) Properties of waste fluid (C_p , μ , ρ , κ)
- 5) Allowable pressure drop
- 6) Minimum temperature to which waste heat can be cooled
- 7) Corrosive elements in the exhaust fluid
- 8) Temperature to which the designed fluid is to be heated

The quality of the heat is based on the waste stream temperature and it is divided into three grades as mentioned in table 8.1 below. Higher the grade, the greater the potential value for heat recovery.

Table 8.1: Different grades of heat

High Grade	Medium Grade	Low Grade
1100°F – 3000°F (593°C – 1649°C)	400°F – 1100°F (204°C – 593°C)	80°F – 400°F (27°C – 204°C)

- **Waste heat use.**

It is important to have a use for any waste heat which may be recovered. In many applications there may be no demand for the heat that is available, with the result the excess heat energy is dumped into the environment. In other situations there may be a long time lag between waste heat production and the demand for heat. Waste heat therefore cannot be used unless there is some use of waste heat and/or some form of thermal storage is available.

Waste heat can be used in various ways, but the major uses include the following:

- 1) preheating combustion air
- 2) generating electrical and mechanical power
- 3) generating process steam
- 4) preheating boiler water
- 5) heating general process liquids and solids
- 6) heating viscous, corrosive, and difficult liquids
- 7) heating, ventilation and refrigeration applications.

The source of heat for applications 1 through 4 is usually hot gases, most frequently from combustion processes. The source of heat for applications 5 through 7 is usually process steam, process liquids/solids or exhaust air.

Table 8.2: Major Applications of Waste Heat Recovery

Application Heat Exchanger Type	Pre-heat combustion air	Generate power	Generate Process steam	Pre-heat boiler water	Heat process liquids	Corrosive and viscous fluids	Heating and ventilation
Tube in tube	✓				✓		
Shell in tube		✓	✓	✓	✓		
Direct Contact	✓						
Solid plate fin	✓						✓
Heat pipes							✓
Runaround coils					✓	✓	✓
Spiral				✓	✓	✓	✓
Coils					✓	✓	✓
Plate and frame					✓	✓	✓
Finned tube							✓
Panel coil					✓		
Cartridge					✓	✓	
Screw conveyor					✓	✓	

- **Adequate space availability to install heat recovery system**

Many facilities have limited physical space to access waste heat streams and to install waste heat recovery systems (e.g., limited floor or overhead space). In such cases it may not be feasible to install the heat recovery system.

- **Primary energy saving possibility**

Often the insertion of a heat exchange system increases the resistance of the fluid streams, resulting in higher fan or pump energy consumption. Heat energy is therefore replaced by electrical energy with no net energy savings.

- **Economic viability or cost effectiveness of WHR technology**

Heat recovery devices can be expensive to install. It is therefore essential that the economic payback period be determined before any investment is undertaken. If proper planning and analysis is not carried out at the concept and design stage, impact of installation of a waste heat recovery device is minimal or may even increase energy cost.

WHR technologies are similar to heat exchangers. The heat exchangers considered unviable are

now being considered for heat recovery for the following reasons

- Heat exchange equipment costs came down making them viable
- Fuel costs increased making an economic case for waste heat recovery
- Regulatory requirements might have made it mandatory to install the same.

8.4 Overview of Waste Heat Recovery Methods and Technologies

Once the need and feasibility to install WHR equipment is established the next logical step is to select the appropriate method for utilization of waste heat and the equipment required.

The common methods by which waste heat is utilized are as follows.

- Direct utilization (eg: for drying or process heating)
- Energy Cascading (Using energy for high temperature application first followed by using the rejected heat for low temperature applications. For example after using high temperature and pressure steam for power generation low temperature and pressure steam can be used for other processes or space heating).
- Cogeneration (Producing electrical power and process heat simultaneously)
- Recuperators (Shell and tube, plate, coil, spiral heat exchangers)
- Regenerators (stationary or rotating type)
- Waste heat boilers

WHR can be classified based on the maximum outlet temperature of recovered waste heat. Accordingly based on waste heat stream temperatures WHR equipment is classified as follows.

- 1) Gas-to-gas heat exchanger (Graphite heat exchangers, stack-type recuperators, direct contact recuperator, plate fin (ceramic and metal) heat exchangers and ceramic tubes)
- 2) Gas-to-liquid heat exchanger (waste heat boilers, economizers and power generators)
- 3) Liquid-to-liquid heat exchanger (shell-and-tube, spiral, coil, finned-tube, plate-and-frame (plate), and run-around heat exchangers)
- 4) Other low-temperature WHR equipment (heat pumps, and heat pipes)

At higher temperature, only gas-to-gas heat transfer is used because of the difficulties encountered at these temperatures. At moderate temperatures (upto ~1000°F), gas-to-liquid transfer is used (steam boilers). At lower temperatures, the dominant mode is liquid-to-liquid heat recovery.

A brief description of commonly encountered heat exchangers is given in sections below.

8.4.1 Gas-to-gas Heat Exchanger

8.4.1.1 Graphite heat exchangers

Graphite heat exchangers have high thermal conductivity and frequently used for heating or cooling of ultra-corrosive liquid chemicals. This specific design allows for heat recovery between two ultra-corrosive fluids.



Source : GAB Neumann's Annular Grove graphite heat exchangers

8.4.1.2 Recuperators

This is the most common type of equipment used for waste heat recovery. In this heat transfer is affected by bringing hot and cold streams adjacently where in heat from hot fluid is transferred through the fluid separation barrier by means of convection and conduction. The radiation recuperator gets its name from the fact that a substantial portion of the heat transfer from the hot gases to the surface of the inner tube takes place by radiative heat transfer. The cold air in the annuals, however, is almost transparent to infrared radiation so that only convection heat transfer takes place to the incoming air.

Based on type of heat transfer they are classified as stack-type or direct contact recuperators. Based on material of construction the direct contact recuperators are further classified as metallic recuperator (used to recover heat from gases at about 1000°C) and ceramic recuperator (used to recover heat from gases at about 1550°C).

Stack-type Recuperators

Stack type recuperators are used when the stack gas temperatures are high and heat transfer dominantly occurs by radiation rather than convection. These are generally co-current heat exchangers and are used for air preheating and is considered cost effective. It has an advantage that hot gases do not have to be rerouted and fans are not required to produce a draft. A major disadvantage is it required substantial heat difference between exhaust gas and preheat air.

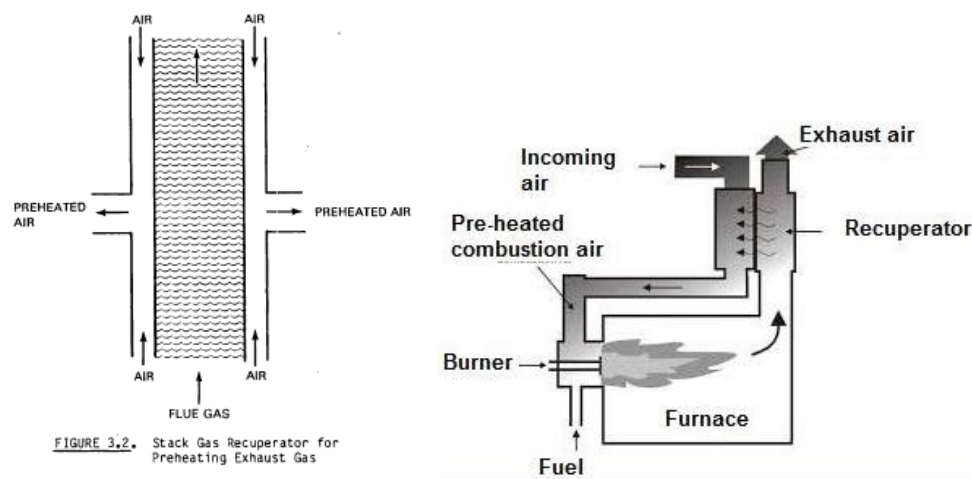


Figure 8.1: Preheating Combustion Air using a Recuperator in Furnace

Direct contact recuperator (ceramic and metal) heat exchangers

Direct contact recuperators provide highest air preheat temperature. These recuperators are also called “checkers”. In this heat exchanger exhaust and air streams are alternated between two sets of checkers. The exhaust stream heats the checkers in one set while the air is being heated by the other. These are considered expensive and require considerable space for duct work and damper arrangements.

Metallic recuperator

The simplest configuration for a recuperator is the metallic radiation recuperator, which consists of two concentric lengths of metal tubing as shown in Figure 8.2

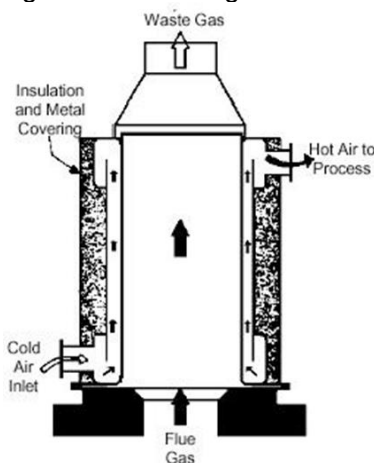


Figure 8.2: Metallic radiation recuperator

The inner tube carries the hot exhaust gases while the external annulus carries the ambient air from the atmosphere which recovers the heat from hot exhaust gases. The heated ambient air is supplied via air inlets of the furnace burners. This equivalent energy of hot combustion air does not have to be supplied by the fuel. So, less fuel is burned for a given furnace loading. The saving in fuel also means a decrease in combustion air requirements and therefore lesser quantities of exhaust gas.

The principal limitation of metal recuperators is the reduced life of the liner at inlet temperatures exceeding 1100°C.

Ceramic Recuperator

In order to overcome the temperature limitation of metallic recuperators, ceramic tube recuperators have been developed. The materials of ceramic recuperators allow operation on the gas side up to 1550°C and on the preheated air side up to 850°C. Early ceramic recuperators were built of tile and joined with furnace cement, and thermal cycling caused cracking of joints and rapid deterioration of the tubes. Later developments introduced various kinds of short silicon carbide tubes which can be joined by flexible seals located in the air headers.

Although the design of this heat exchanger may change with its particular application, three types are widely used.

Flat plate recuperator

Flat plate recuperator (Figure 8.3) consists of a series of metal (usually aluminium) plates separating 'hot' and 'cold' air or gas flows sandwiched in a box-like structure. The plates are sealed in order to prevent intermixing of the two fluid flows. They are often used in ducted air-conditioning installations to reclaim heat from the exhaust air stream without cross contamination.

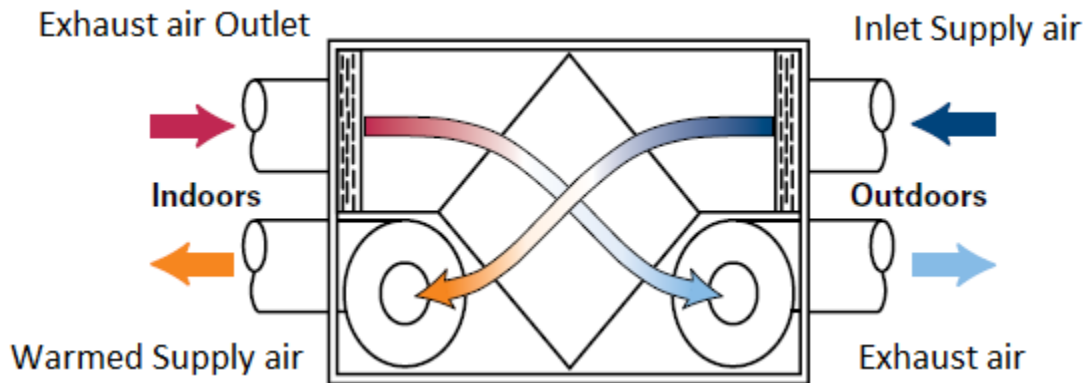


Figure 8.3: Flat Plate Recuperator

8.4.1.3 Plate fin (ceramic and metal) heat exchangers

Plate fin heat exchangers overcome the problems associated with direct contact types and for high temperature applications ($> 1360^{\circ}\text{F}$ discharge air and $> 1500^{\circ}\text{F}$ for flue gas) are available in both metal and ceramic designs

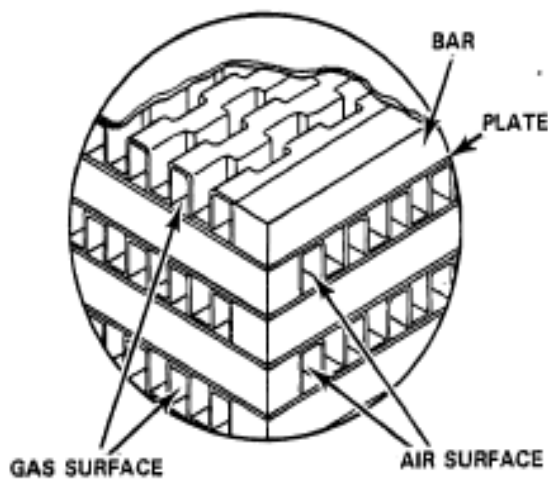


Figure 8.4: Plate Fin Heat Exchanger

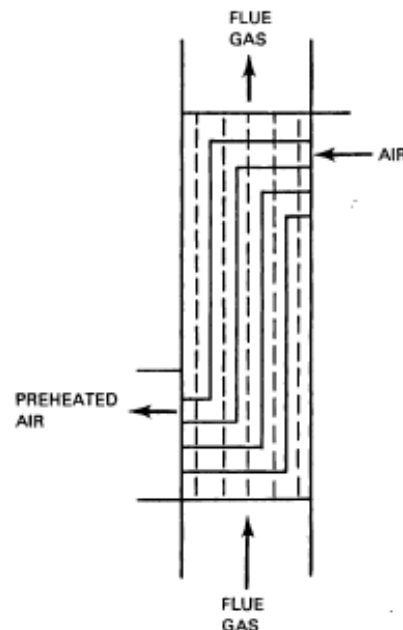


Figure 8.5: Metallic Recuperator with cross-counter flow design

8.4.1.4 Ceramic tubes

These are tubular heat exchangers made of ceramic tubes. They have problems of differential thermal expansion of the ceramic tubes and related hardware which can cause cracking and sealing problems.

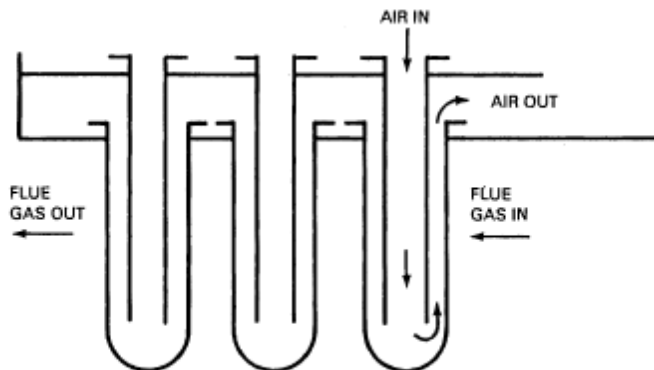


Figure 8.6: Ceramic Re-entrant Tube Heat Exchanger

8.4.2 Gas-to-liquid heat exchanger

8.4.2.1 Waste Heat Boilers

Waste heat boilers are available with fire-tube or water-tube designs in both extended surface and smooth tube models.

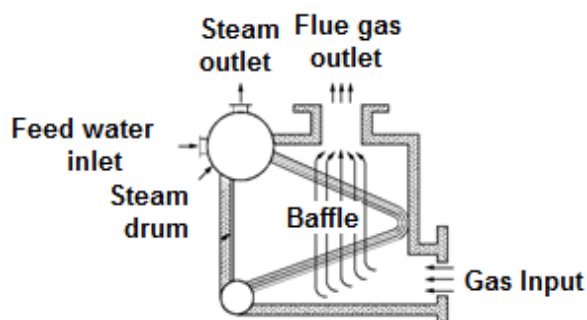


Figure 8.7: Generating Steam using Waste Heat Boiler

8.4.2.2 Economizers

Economizers operate on exhaust gas that already passed through either recuperators or waste heat boilers and are intended to operate waste heat from other heat utilization or recovery equipment. The dew point condensation of exhaust gases sets the lower operating limit for conventional economisers. Direct contact economisers using liquid spray etc. capture the latent heat (~ 1000 BTU/lb of water vapor contained) as well as the remaining sensible heat.

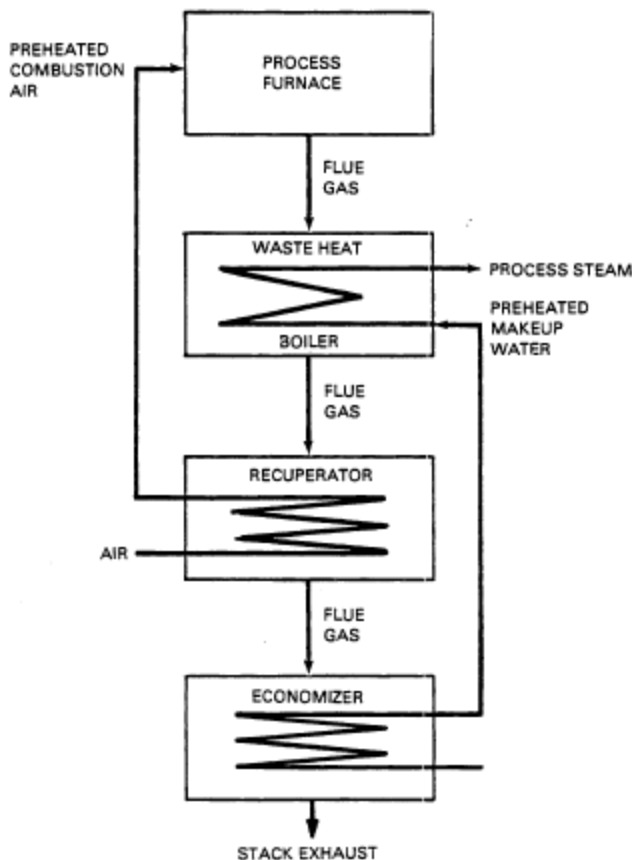


Figure 8.8: Schematic Diagram of Waste Heat Boiler Recuperator and Economiser

8.4.2.3 Power Generators

Cogeneration where process steam and power are jointly generated is used to reduce heat wastage. Organic rankine cycle is used where waste heat temperatures are lower compared to conventional steam cycle systems.

Organic Rankine Cycle (ORC)

ORC unit is a power generation plant which on a mini-scale is typically in the range of 10–250 kW. Unlike the traditional power plant where working fluid is water, evaporated gas is steam, and engine is steam turbine, the ORC system uses working fluids which boil at much lower temperatures and pressures than water. Typical organic fluids used include R234fa, R134, pentane, cyclopentane, n-heptane, hexane, and toluene. The ORC systems can even work on low temperature heat sources (90–300°C) for heat recovery.

The schematic of ORC system is shown in Figure 8.9. The ORC system is based on the principle whereby organic fluid is heated causing it to evaporate, and the resulting gas is used to turn an organic vapour turbine (expander) which is coupled to a generator producing power. The exhaust vapour is subsequently condensed in water or air-cooled condenser and is recycled to the vaporiser by a liquid pump.

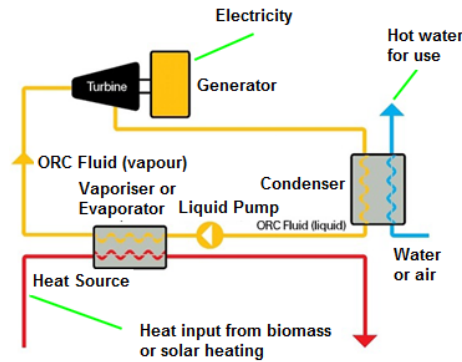


Figure 8.9: Schematic of a Small Scale Organic Rankine Cycle

8.5 Liquid-to-liquid heat exchanger :

8.5.1.1 Shell-and-tube

The most frequently used industrial heat exchanger is the shell-and-tube heat exchanger. It can be made from any material or combination of materials including metal, graphite and glass. The configuration of this heat exchanger is multiple parallel, small-diameter tubes are mounted inside a single, large-diameter tube wherein one fluid flows on the inside of the tubes, while the other fluid is forced through the shell and over the outside of the tube. To ensure that the shell-side fluid will flow across the tubes, and thus induce higher heat transfer, baffles are placed in the shell as shown in figure 8.10. Depending on the head arrangement at the end of the exchanger, one or more tube passes may be used.

The disadvantage of this exchanger is difficulty in cleaning the outside of the tube bundle because of which it is normally used for fluids where significant fouling is not expected.



Figure 8.10: Shell-tube heat exchanger with one pass

8.5.1.2 Plate heat exchanger

Plate heat exchanger also called compact heat exchangers (have surface areas greater than $650 \text{ m}^2/\text{m}^3$), (Figure 8.11) are primarily used in gas-flow systems where the overall heat-transfer coefficient are low and it is desirable to achieve a large surface area in a small volume. They can easily be expanded or contracted to accommodate future system modification. These heat

exchangers consists of a large number of thin metal plates (usually stainless steel, titanium, or nickel), which are clamped tightly together and sealed with gaskets. The thin plates are profiled so that 'flow ways' are created between the plates when they are packed together. This leads to formation of large surface area, across which heat transfer can take place. Ports located at the corners of the individual plate separate the 'hot' and 'cold' fluid flows and direct them to alternate passages so that no intermixing of hot and cold fluid occurs. The whole exchanger experiences a counter-flow pattern.

The maximum operating temperature is usually about 130°C if rubber sealing gaskets are fitted, but the operating temperature can be extended to 200°C if compressed asbestos fibre seals are used.

The advantage of these heat exchangers are it is easier to clean, and is only one-fourth the size of the shell-and-tube heat exchangers, less prone to fouling and less costly to operate in the long-term than shell-and-tube heat exchangers. For similar applications, plate heat exchangers may be smaller, more efficient, have less internal volume, and cost less than shell-and-tube heat exchangers.

The high-efficiency, low-approach temperatures, counter-flow design, relative ease of fabrication from exotic materials, and cleanability are making the plate heat exchanger attractive for some very difficult liquid-to-liquid applications, such as recovering heat from geothermal brines and manufacturing of chemicals and pharmaceuticals.

Although plate heat exchangers are typically meant for liquid to liquid heat exchange, they are now available for even gas to liquid and even for gases laden with tar with provision of cleaning system.

8.5.1.3 Spiral heat exchanger

Spiral heat exchangers use a double spiral of strip material sandwiched between two plates providing separate spiral flow paths for the fluids as shown in figure 8.12. They can be dismantled easily for cleaning and inspection.

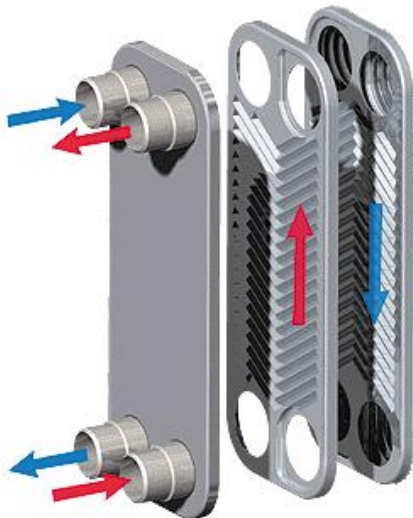


Figure 8.11: Plate Heat Exchanger

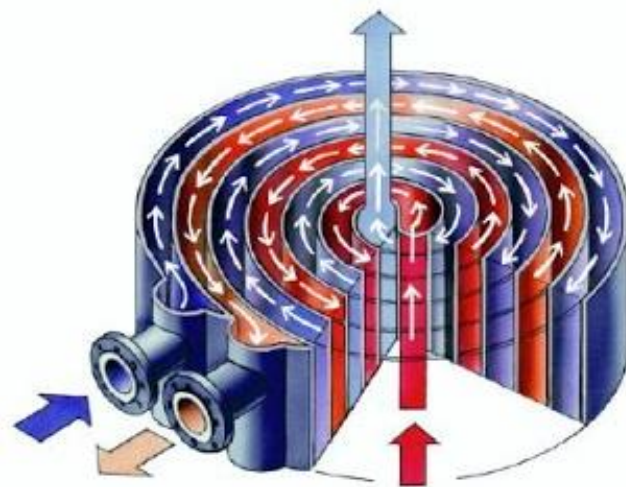


Figure 8.12: Spiral Heat Exchanger

8.5.1.4 Coil heat exchangers

Coils are often used for cooling small amounts of fluid keeping a critical mechanical equipment cool. Heat is transferred between the fluid in the coil and a fluid bath.

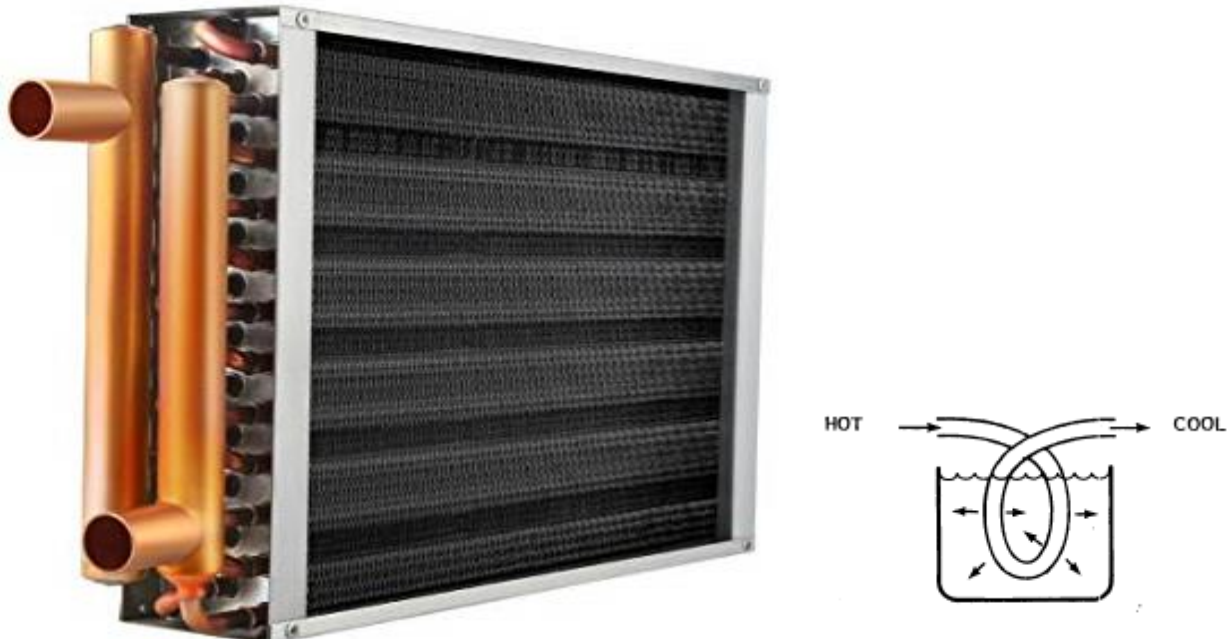


Figure 8.13: Coil Heat Exchanger

8.5.1.5 Finned-tube heat exchangers

Tube-type heat exchangers often use fins on the heat exchanger tubing. Fins can increase the heat transfer rate by increasing the effective heat transfer area. The fins typically run circumferentially around the outside of the tube, although longitudinal fins and internal fins are also used. The fins may be solid or segmented. (Segmented fins are lighter and increase the heat transfer rate by increasing turbulence.)

8.5.1.6 Run-around Coils

When two recuperative heat exchangers are linked together by a secondary fluid which transports heat between them, the system is known as a run-around coil. The cooling system in an automobile where the engine is the source of heat and the air is the sink and the heat is transferred using coolant liquid is an example of run-around coil type heat exchanger. Run-around coils are often employed to recover waste heat from exhaust air streams and to preheat incoming supply air. This will thereby help avoid the risk of cross-contamination between the two air streams. Such a system is shown in Figure 8.14.

Run-around coils have the advantage that they can be used in applications where the two fluid streams are physically far apart to use a recuperative heat exchanger. While this feature is usually considered advantageous, it can increase energy consumption since a pump is introduced into the system. It may also result in heat loss from the secondary fluid. This makes it important to insulate the pipe work circuit; otherwise, the overall effectiveness of the system

will be reduced. Run-around coils are relatively inexpensive to install since they utilise standard air/water heating coils.

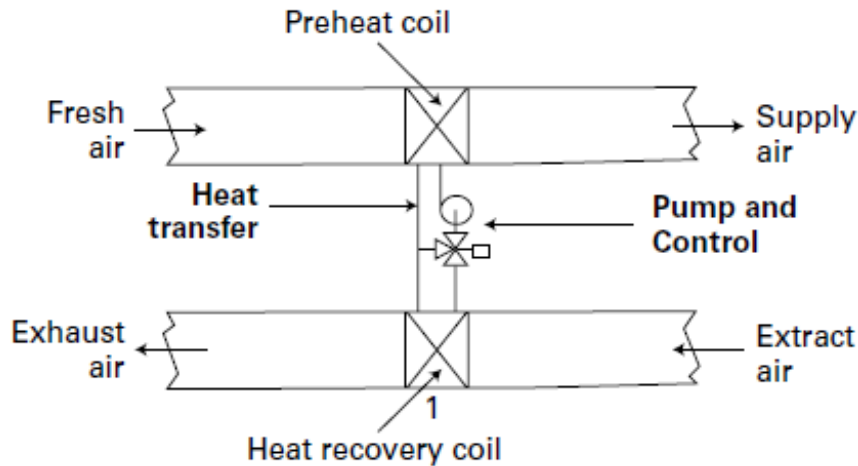


Figure 8.14: Run-around Coil Heat Recovery System

8.5.2 Regenerative Heat Exchangers

In a regenerative heat exchanger a matrix of material is alternately passed from a hot fluid to a cold fluid, so that heat is transferred between the two in a cyclical process. The most commonly type of regenerative heat exchanger is thermal wheel (Figure 8.15) which has a matrix of material mounted on a wheel rotating at about 10 rpm, through hot and cold fluid streams alternatively. The major advantage of the thermal wheel is the large surface area to volume ratio which results in a relatively low cost per unit surface area.

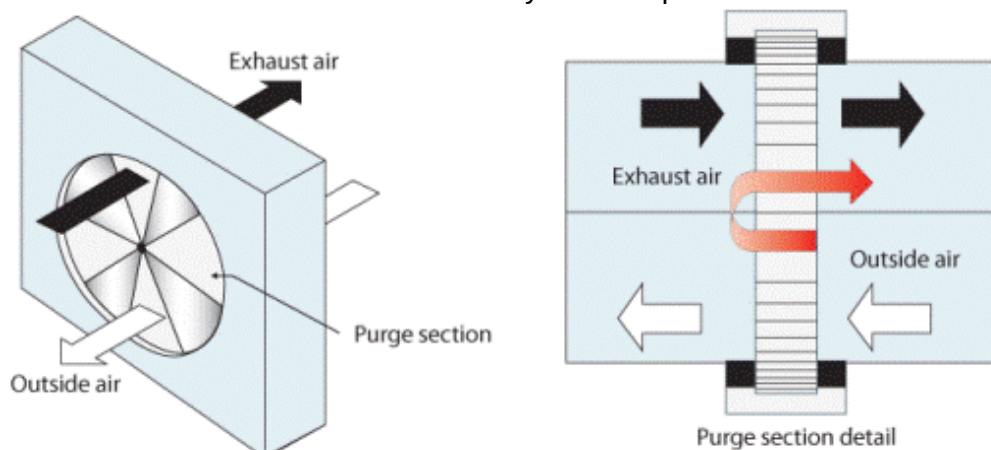


Figure 8.15: Thermal Wheel

The matrix material in the thermal wheel is usually an open structured metal made of knitted stainless steel or aluminium wire, or corrugated sheet aluminium or steel. For use at higher temperatures honeycomb ceramic materials are used. Although thermal wheels are usually used solely to recover sensible heat, it is possible to reclaim the enthalpy of vaporisation of the moisture in the 'hot' stream passing through the thermal wheel. This is achieved by coating a non-metallic matrix with a hygroscopic or desiccant material such as lithium chloride.

The main disadvantage of thermal wheels is that there is the possibility of cross-contamination between the air streams. This can be reduced considerably by ensuring that the cleaner of the two fluids is maintained at the highest pressure and with a use of purging device.

Case Example

A rotary heat regenerator was installed on a two colour printing press to recover some of the heat, which had been previously dissipated to the atmosphere, and used for drying stage of the process. The outlet exhaust temperature before heat recovery was often in excess of 100°C. After heat recovery the temperature was 35°C. Percentage heat recovery was 55% and pay back on the investment was estimated to be about 18 months. Cross contamination of the fresh air from the solvent in the exhaust gases was at a very acceptable level.

8.5.3 Heat Pump

A heat pump is essentially a vapour compression refrigeration machine which takes heat from low temperature source such as air or water and upgrades it to be used at higher temperature. Unlike a conventional refrigeration machine, using heat pump the heat produced at the condenser is used and not wasted to the atmosphere. The Figure 8.16 shows the operating principle of simple vapour compression heat pump.

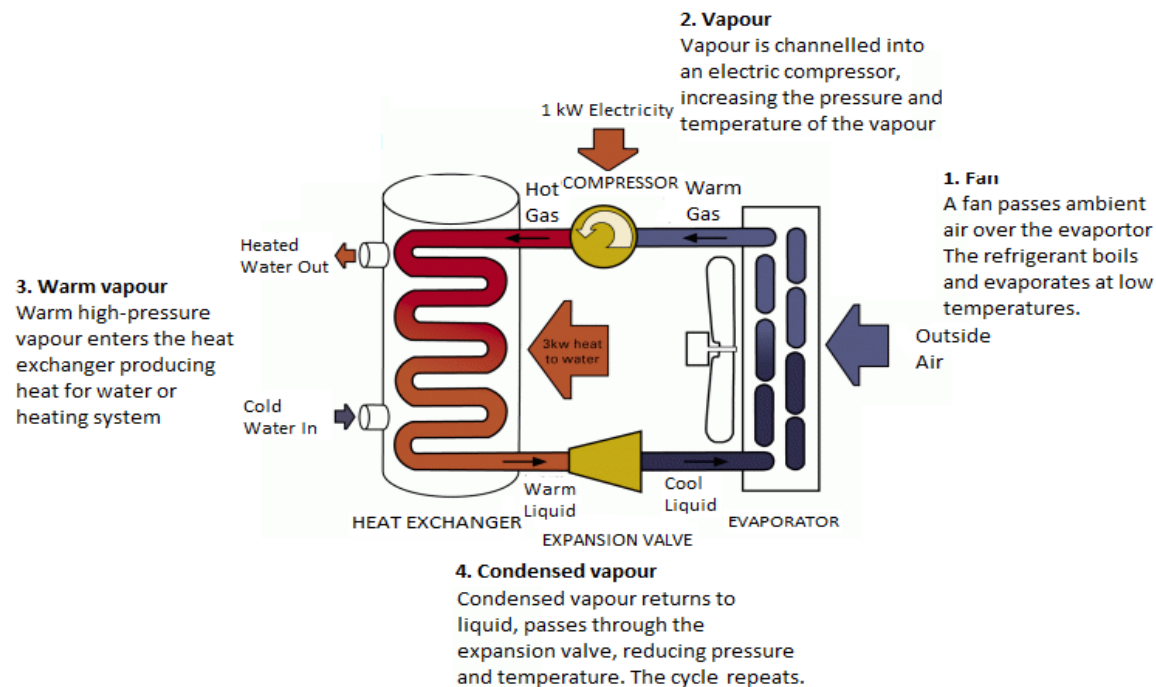


Figure 8.16: Vapour Compression Heat Pump

The performance of the vapour compression refrigeration cycle is quantified by the coefficient of performance (COP), which can be expressed as follows:

For a refrigeration machine:

$$COP_{Ref} = \frac{\text{Useful Refrigeration Output}}{\text{Net Work Input}}$$

For a heat pump:

$$COP_{Hp} = \frac{\text{Useful Heat Rejected Cycle}}{\text{Net Work Input}}$$

Heat pumps are well suited to applications where the evaporating and condensing temperatures are close together such as in the cases when recovering heat from exhaust air in heating and air conditioning applications. As a result, heat pumps are often used in air conditioning applications.

8.5.4 Heat Pipe

Heat pipes are devices which can transfer 1000 times more thermal energy than copper. It can be used in traditionally difficult heat exchange environments such as high particulate gases, dirty liquids, corrosive environments, low temperature gradients.

Heat pipe is basically a metal and metal alloy tube that is sealed on both ends and with an internal wick or mesh along the interior of the pipe. The Heat Pipe comprises of three elements – a sealed container, a capillary wick structure and a working fluid. The capillary wick structure is integrally fabricated into the interior surface of the container tube and sealed under vacuum. Thermal energy applied to the external surface of the heat pipe is in equilibrium with its own vapour as the container tube is sealed under vacuum and causes the working fluid near the surface to evaporate instantaneously. Vapour thus formed absorbs the latent heat of vaporization and this part of the heat pipe becomes an evaporator region. The vapour then travels to the other end the pipe where the thermal energy is removed causing the vapour to condense into liquid again, thereby giving up the latent heat of the condensation. This part of the heat pipe works as the condenser region. The condensed liquid then flows back to the evaporated region. (Figure 8.17) is Heat pipe has a working fluid within a vacuum and typical working fluids used include liquid nitrogen, methanol, water, and sodium. The temperature range along with fluid type and compatible metals tubes are given the table 8.3 below.

Table 8.3: Temperature Ranges for Heat-Transfer Fluids Used in Heat Pipes

Fluid	Temperature range (°C)	Compatible Metals
Nitrogen	-180 to 80	Stainless steel
Ammonia	-70 to 60	Nickel, Aluminum, Stainless steel
Methanol	-45 to 115	Nickel, Copper, Stainless steel
Water	5 to 215	Nickel, Copper
Mercury	190 to 535	Stainless steel
Sodium	510 to 870	Nickel, Stainless steel
Lithium	870 to 1480	Alloy of Niobium and Zirconium
Silver	1480 to 1980	Alloy of Tantalum and Tungsten

The performance (amount of heat that can be transferred) of a heat pipe is a function of its length, diameter, wick structure, and overall shape. The larger the diameter, the more power that can be transported, but longer the length, the less capable is the performance.

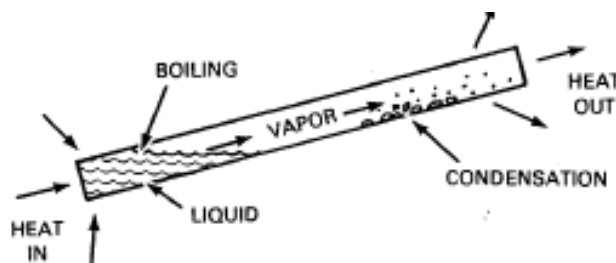


Figure 8.17: Heat Pipe

The heat pipes are used in following industrial applications:

a. Process to Space Heating: The heat pipe heat exchanger transfers the thermal energy from process exhaust for building heating. The preheated air can be blended if required. The requirement of additional heating equipment to deliver heated make up air is drastically reduced or eliminated.

b. Process to Process: The heat pipe heat exchangers recover waste thermal energy from the process exhaust and transfer this energy to the incoming process air. The incoming air thus become warm and can be used for the same process/other processes and reduces process energy consumption.

c. HVAC Applications:

Cooling: Heat pipe heat exchangers pre-cool the building make up air in summer and thus reduces the total tons of refrigeration, apart from the operational saving of the cooling system. Thermal energy is supply recovered from the cool exhaust and transferred to the hot supply make up air.

Advantages of heat pipe system

- Heat pipes operates independently so are not vulnerable to a single pipe failure.
- No cross contamination occurs as hot and cold sides are separated by a splitter plate.
- No wear and tear occurs as there are no moving parts inside the heat pipe.
- No additional power is required to run the system

Industrial applications:

- Preheating of boiler combustion air
- Recovery of Waste heat from furnaces
- Reheating of fresh air for hot air driers
- Recovery of waste heat from catalytic deodorizing equipment
- Reuse of Furnace waste heat as heat source for other oven
- Cooling of closed rooms with outside air
- Preheating of boiler feed water with waste heat recovery from flue gases in the heat pipe economizers.
- Drying, curing and baking ovens
- Waste steam reclamation
- Brick kilns (secondary recovery)
- Reverberatory furnaces (secondary recovery)
- Heating, ventilating and air-conditioning systems

Case Example

In a hospital, the HVAC system exhausts 140 m³/min of air which has a heat recovery potential of 28225kcal/hr. Calculate the savings and payback period of heat recovery system to be installed at a cost of BDT 1,12,000.

Solution:

Savings in Hospital Cooling Systems

	Units	Value
Volume of exhaust	m ³ /min	140
Heat recovery potential	kcal/hr	28225
Conversion: 1 kcal/hr	TR	0.00033069
Electricity required	KW/TR	0.8
Plant capacity reduction	TR	9.33
Electricity cost(operation)	BDT/Million kcal (based on 0.8KW/TR)	268
Plant capacity reduction cost (Capital)	BDT/TR	12,000
Capital cost savings	BDT	1,12,000/-
Payback period	hours	16570

8.5.5 Thermo-compressor

In many cases, very low pressure steam are reused as water after condensation for lack of any better option of reuse. In many cases it becomes feasible to compress this low pressure steam by very high pressure steam and reuse it as a medium pressure steam. The major energy in steam, is in its latent heat value and thus thermo compressing would give a large improvement in waste heat recovery.

The thermo-compressor is a simple equipment with a nozzle where HP steam is accelerated into a high velocity fluid. This entrains the LP steam by momentum transfer and then recompresses in a divergent venturi. A figure of thermo-compressor is shown in Figure 8.18.

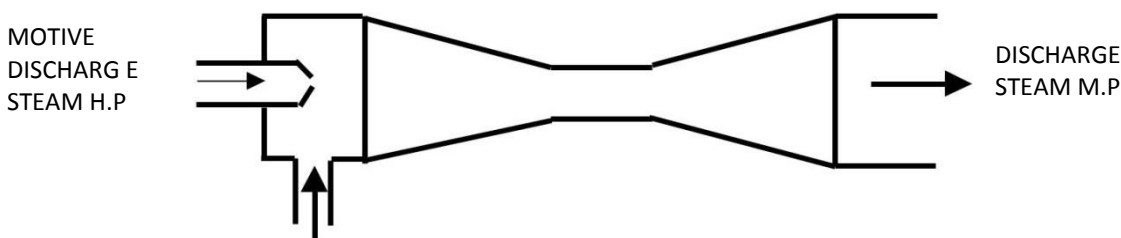


Figure 8.18: Thermo-compressor

It is typically used in evaporators where the boiling steam is recompressed and used as heating steam

Case Example

Exhaust steam from evaporator in a fruit juice concentrator plant was condensed in a pre-condenser operation on cooling water upstream of a steam jet vacuum ejector

Equipment Suggested	Alt-1 Thermo compressor Alt-2 shell & tube exchanger
Cost of thermo compressor	BDT 1.5Lakhs
Savings of jacket steam due to recompression of vapour	BDT 5.0 Lakhs per annum
Cost of shell & tube exchanger to pre heat boiler feed water	BDT 75,000/-
Savings in fuel cost	BDT 4.5 Lakhs per annum

The recovery technologies for different heat source are given below

Table 8.4: Waste of Heat Recovery Technologies for High range heat sources

High range Heat Source	Temperature range (°C)	Recovery method	Typical uses	Type of heat exchanger (Gas-Gas, Gas-Liquid)	Large temperature differentials permitted	No Cross - contamination
Nickel refining furnace	1370 –1650	RR, CR	1	G-G	x	x
Aluminium refining furnace	650-760	CHW,CR, WHB	1,2,3,5	G-G, G-L	x	x
Zinc refining furnace	760-1100	RR, CR	1	G-G	x	x
Copper refining furnace	760- 815	CHW,CR, WHB	1,2,3,5	G-G, G-L	x	x
Steel heating furnaces	925-1050	RR, CR	1	G-G	x	x
Copper reverberatory furnace	900-1100	RR, CR	1	G-G	x	x
Open hearth furnace	650-700	CHW,CR	1,2,3,5	G-G, G-L	x	x
Cement kiln (Dry process)	620- 730	CHW,CR	1,2,3,5	G-G, G-L	x	x
Glass melting furnace	1000-1550	RR, CR	1	G-G	x	x
Hydrogen plants	650-1000	CHW,CR, WHB	1,2,3,5	G-G, G-L	x	x
Solid waste incinerators	650-1000	CHW,CR, WHB	1,2,3,5	G-G, G-L	x	x
Fume incinerators	650-1450	CHW,CR, WHB	1,2,3,5	G-G, G-L	x	x

Recovery Methods

RR- Radiation Recuperator; **CR** - Convection Recuperator; **MHW** - Metallic Heat Wheel; **CHW** - Ceramic Heat Wheel **WHB** - Waste-heat Boilers

Typical Uses

1.Combustion air preheat **2.** Space preheat **3.** Boiler makeup water preheat **4.** Boiler feed water preheat
5. Domestic hot water **6.** Hot water or steam generation. **7.** Liquid feed flows requiring heating

Source: W. Turner Energy Management Handbook, 2007; Waste Heat Recovery: Technology and Opportunities in U.S Industry, 2008.

Table 8.5: Waste Heat Recovery Technologies for medium range heat sources

Heat Source	Temperature range (°C)	Recovery method	Typical uses	Type of heat exchanger (Gas-Gas, Gas-Liquid)	Large temperature differentials permitted	No Cross - contamination
Steam boiler exhausts	230-480	MHW, HHW, PHE	4,6,7	G-G, G-L	-	X
Gas turbine exhausts	370-540	MHW, HHW, PHE	4,6,7	G-G, G-L	-	X
Reciprocating engine exhausts	315-600	CR, HP, WHB, CHW	1	G-G	X	X
Reciprocating engine exhausts (turbo charged)	230- 370	MHW, HHW, PHE	4,6,7	G-G, G-L	-	X
Heat treating furnaces	425 - 650	CR, HP, WHB, CHW	1	G-G	X	X
Drying and baking ovens	230 - 600	CR, HP, WHB, CHW	1	G-G	X	X
Catalytic crackers	425 - 650	CR, HP, WHB, CHW	1	G-G	X	X
Annealing furnace cooling systems	425 - 650	CR, HP, WHB, CHW	1	G-G	X	X

Recovery Methods

CR - Convection Recuperator; **CHW** - Ceramic Heat Wheel; **PHE** – Plate type heat exchanger ;
HHW - Hygroscopic Heat Wheel; **MHW** - Metallic Heat Wheel; **FHE**- Finned-tube Heat exchanger;
ST- shell and tube exchanger; **WHB** - Waste-heat Boilers; **HP** - Heat Pipe

Typical Uses

1. Combustion air preheat
2. Space preheat
3. Boiler makeup water preheat
4. Boiler feed water preheat
5. Domestic hot water
6. Hot water or steam generation.
7. Liquid feed flows requiring heating

Source: W. Turner Energy Management Handbook, 2007; Waste Heat Recovery: Technology and Opportunities in U.S Industry, 2008.

Table 8.6: Waste Heat Recovery Technologies for low range heat sources

Heat Source	Temperature range (°C)	Recovery method	Typical uses	Type of heat exchanger (Gas-Gas, Gas-Liquid)	Large temperature differentials permitted	No Cross - contamination
Process steam condensate	55-88	PHE,MHW, HHW	2	G-L	-	x
Cooling water from:						
Furnace doors	32-55	PHE,MHW, HHW	2	G-L	-	x
Bearings, Welding machines, Injection molding machines.	32-88	PHE,MHW, HHW	2	G-L	-	x
Annealing furnaces	66-230	FHE, WHB, ST	3,6,7	G-G,G-L	x	x
Forming dies, pumps	27-88	PHE,MHW, HHW	2	G-L	-	x
Air compressors	27-50	PHE,MHW, HHW	2	G-L	-	x
Air conditioning and refrigeration condensers	32-43	PHE,MHW, HHW	2	G-L	-	x
Drying, baking and curing ovens	93-230	FHE, WHB, ST	2	G-L		x
Hot processed liquids	32-232	FHE, WHB, ST	3,6,7	G-G,G-L	x	x

Recovery Methods

MHW - Metallic Heat Wheel; **HHW** - Hygroscopic Heat Wheel; **PHE** – Plate type heat exchanger ; **FHE** Finned-tube Heat exchanger; **ST**- Shell and tube exchanger; **WHB** - Waste-heat Boilers

Typical Uses

Combustion air preheat **2**. Space preheat **3**. Boiler makeup water preheat **4**. Boiler feed water pre heat **5**. Domestic hot water **6**. Hot water or steam generation. **7**. Liquid feed flows requiring heating

Source: W. Turner Energy Management Handbook, 2007; Waste Heat Recovery: Technology and Opportunities in U.S. Industry, 2008

8.6 Heat exchanger configurations

The two most commonly used heat exchanger flow configurations are *counter flow* and *parallel flow*. These flow patterns are represented in Figures 8.19 and 8.20 respectively, along with their characteristic temperature profiles.

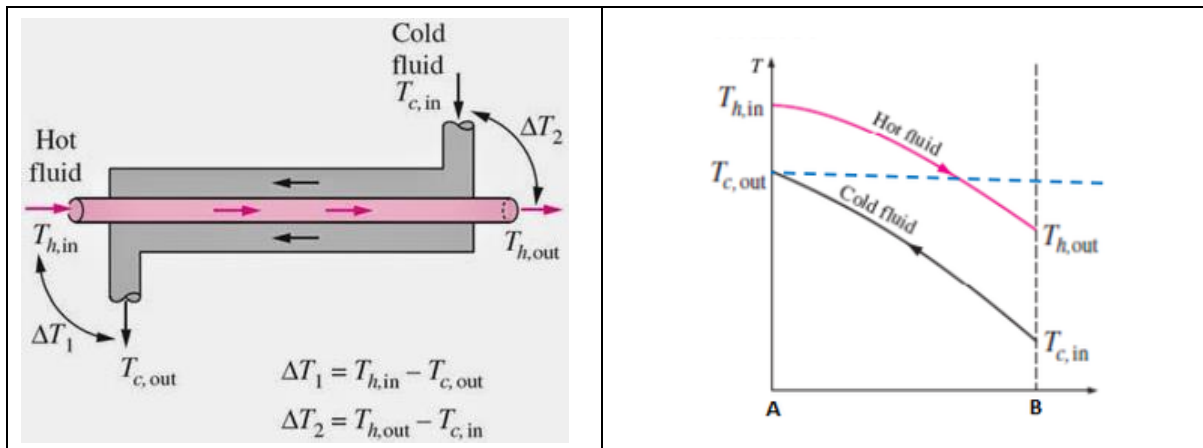


Figure 8.19: Counter Flow Heat Exchanger

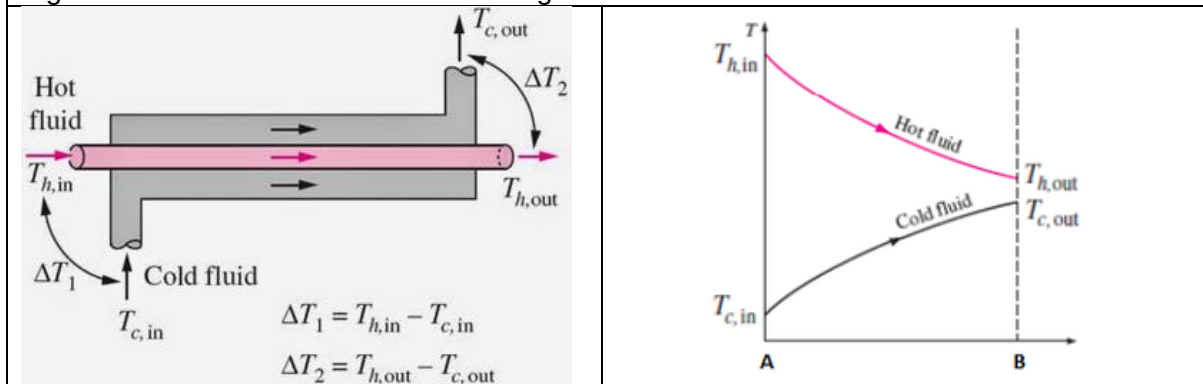


Figure 8.20: Parallel Flow Heat Exchanger

It should be noted that with the parallel flow configuration the 'hot' stream is always warmer than the 'cold' stream. With the counter flow configuration it is possible for the outlet temperature of the cold fluid to be higher than the outlet temperature of the hot fluid.

The general equations which govern the heat transfer in recuperative heat exchangers are as follows:

$$Q = m_h C_h (t_{h.in} - t_{h.out}) = m_c C_c (t_{c.in} - t_{c.out})$$

and

$$Q = U A_o (LMTD) K$$

Where,

Q is the rate of heat transfer (W),

m_h is the mass flow rate of hot fluid (kg/s),

m_c is the mass flow rate of cold fluid (kg/s),

C_h is the specific heat of hot fluid (J/kgK),

C_c is the specific heat of cold fluid (J/kgK),

$t_{h.in}$ and $t_{h.out}$ are the inlet and outlet temperatures of hot fluid

$t_{c.in}$ and $t_{c.out}$ are the inlet and outlet temperatures of cold fluid

U is the overall heat transfer coefficient (i.e. U value) (W/m²K),

A_o is the outside surface area of heat exchanger (m²),

LMTD is the logarithmic mean temperature difference

K is the constant which is dependent on the type of flow through the heat exchanger (K = 1 for counter-flow and parallel flow, and is therefore often ignored).

The logarithmic mean temperature difference (LMTD) can be determined by:

$$LMTD = \frac{\Delta T_1 - \Delta T_2}{\ln(\Delta T_1 / \Delta T_2)}$$

where,

$\Delta T_1 = t_{h.in} - t_{c.out}$ and $\Delta T_2 = t_{h.out} - t_{c.in}$ for Counter Flow Heat Exchanger

$\Delta T_1 = t_{h.in} - t_{c.in}$ and $\Delta T_2 = t_{h.out} - t_{c.out}$ for Parallel Flow Heat Exchanger

Case Example: Heat recovery from heat treatment furnace

In a heat treatment furnace, the exhaust gases are leaving the furnace at 900°C at the rate of 2100 m³/hour. The total heat recoverable at 180°C final exhaust can be calculated as

$$Q = V \times \rho \times C_p \times \Delta T$$

Q is the heat content in kCal

V is the flow rate of the substance in m³/hr

ρ is density of the flue gas in kg/m³

C_p is the specific heat of the substance in kCal/kg °C

ΔT is the temperature difference in °C

C_p (Specific heat of flue gas) = 0.24 kCal/kg/°C

Heat available (Q) = 2100 x 1.19 x 0.24 x (900-180) = 4,31,827 kCal/hr

By installing a recuperator, this heat can be recovered to pre-heat the combustion air. The fuel savings would be 33% (@ 1% fuel reduction for every 22°C reduction in temperature of flue gas).

8.7 Heat Transfer Augmentation

Principles of heat transfer for waste heat recovery are similar to any heat exchange mechanisms. To promote the heat transfer co-efficient h, three different methods are used. They are

- Active method
- Passive Method
- Combined active and passive method

Active Method employs supplementary power supply. Passive method includes twisted tapes, ribbons, wire coils, indentation of heat transfer surface, etc. to break the thermal boundary layer to promote the heat transfer coefficient. In some cases, both the active and passive methods may be combined to promote the heat transfer coefficient.

Module 3

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1 ELECTRICAL SYSTEMS

1.1. Introduction to Electric Power Supply Systems

An electric power supply system in a country is comprised of generating units that produce electricity; high voltage transmission lines that transport electricity over long distances; distribution lines that deliver the electricity to customers; substations that connect the pieces to each other; and energy control centers to coordinate the operation of the components. Figure 1.1 shows a simple electric supply system with transmission and distribution network and linkages from electricity sources to end-user.

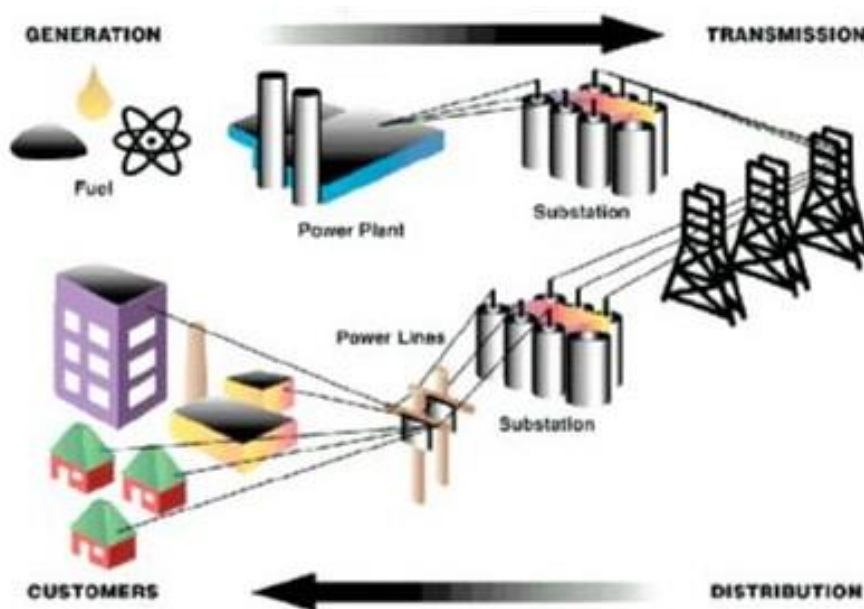


Figure 1.1: Electric supply system

Power Generation Plant

Fossil fuels such as coal, oil and Natural Gas, nuclear energy, and falling water (hydel) are commonly used energy sources in the power generating plant. A wide and growing variety of unconventional generation technologies and fuels also have been developed, including cogeneration, solar energy, wind generators, and waste material. About 58% of power generation capacity in Bangladesh is from Natural gas based power plant.

The Installed capacity of Power Generation (by plant type) as on Sept, 2018 is given

below:

Plant Type	Installed Capacity (MW)
Power Import	1160
Solar PV	3
Hydro	230
Steam Turbine	2404
Combined Cycle (CC)	5871
Gas Turbine (GT)	1322
Reciprocating Engine (RE)	6053
Total*	17043

*Including Captive Power & Renewable Energy Total Installed Capacity (17,043 + 2,800+290) = 20,133 MW

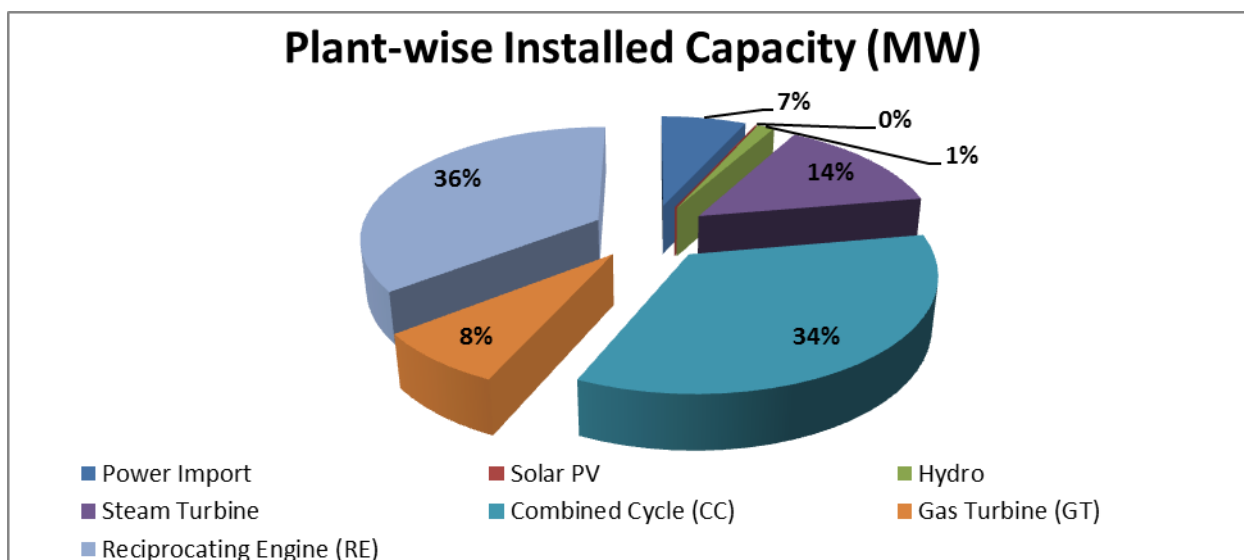
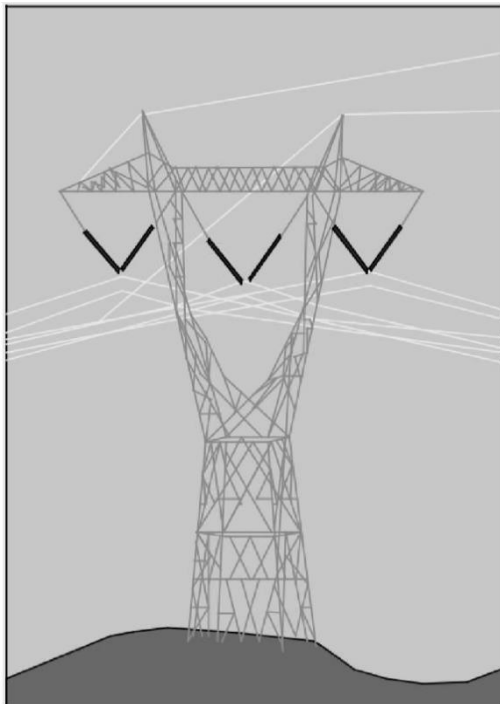


Figure 1.2 a: Primary Grid System in Bangladesh



Fuel-wise Installed Capacity (MW)

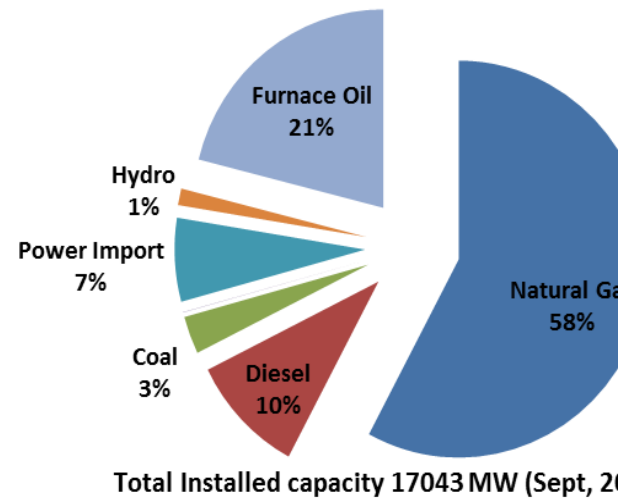


Figure 1.2 b: Primary Grid System in Bangladesh

The peak demand is expected to be about 17,304 MW in FY2020 and 25,199 MW in 2025 and 33,708 MW in 2030 based on 7% GDP growth rate.

The maximum power station in Bangladesh run via natural gas, some of them are run by HFO (Heavy fuel oil). Mainly Diesel oil and Furnace oil are used for thermal power plant.

Transmission and distribution lines

As per Grid Code of Bangladesh, allowable range for frequency variation is 49.0 to 51.0 Hz. Power plants typically produce 50 cycle/second (Hertz) alternating-current (AC) electricity with Terminal voltage of different generators are 11 KV, 11.5 KV and 15.75 KV. The transmission and distribution network include sub-stations, lines and distribution transformers. At the power plant, the 3-phase voltage is stepped up to a higher voltage for transmission on cables strung on cross-country towers. High voltage transmission is used so that smaller, more economical wire sizes can be

Figure 1.3 Cross Country Tower

employed to carry the lower current and to reduce losses. Sub-stations, containing step-down transformers, reduce the voltage for distribution to industrial users. The voltage is further reduced for commercial facilities. Electricity must be generated, as and when it is needed since electricity can not be stored virtually in the system here is no difference between a transmission line and a distribution line except for the voltage level and power handling capability. Transmission lines are usually capable of transmitting large quantities of electric energy over great distances. They operate at high voltages.

Distribution lines carry limited quantities of power over shorter distances. High voltage (HV) and extra high voltage (EHV) transmission is the next stage from power plant to transport A.C. power over long distances at voltages like; 400kV, 230 kV and 132 kV. These are called as the primary grid system. Where transmission is over 1000KM, high voltage direct current transmission (HVDC) is also favoured to minimize the losses.

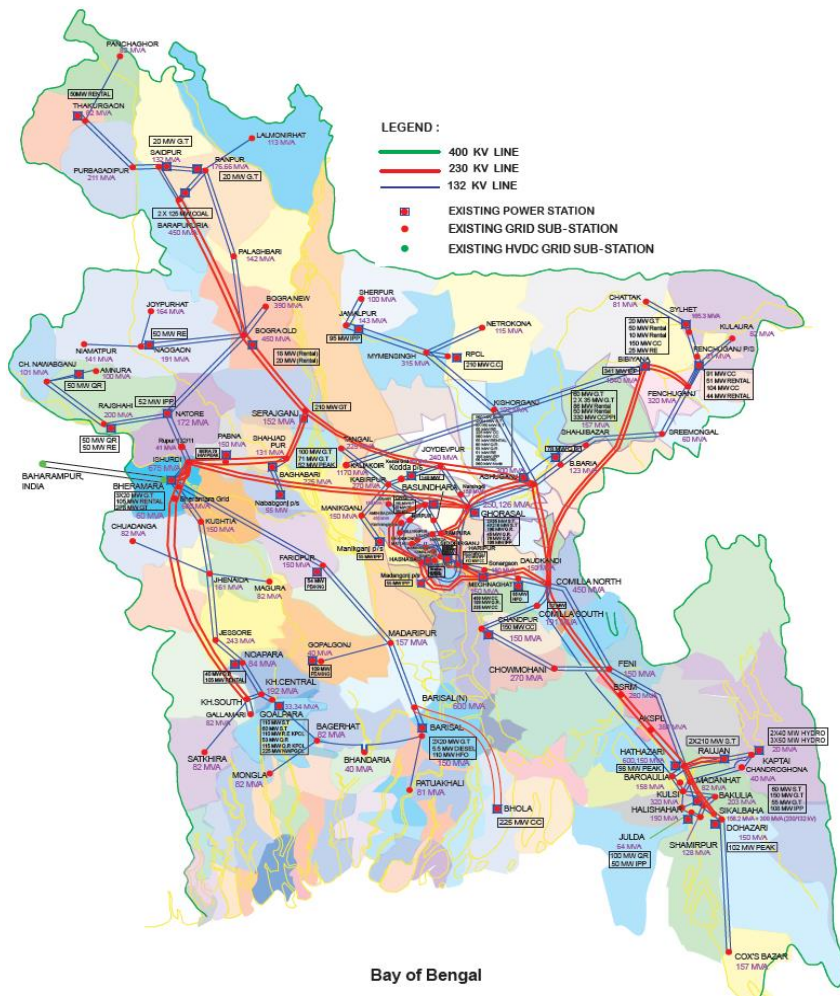
Sub-transmission network at 230 kV, 132kV constitutes the next link towards the end user.

High voltage transmission network that transmits the power to grid substation transformers to be stepped down at 33 kV, 11 kV and 0.4 kV for delivery to the consumers of various categories.

Distribution at 11kV/6.6kV/3.3kV constitutes the last link to the consumer, who is connected directly or through transformers depending upon the drawl level of service.

Voltage drop in the line is in relation to the resistance and reactance of line, length and the current drawn. For the same quantity of power handled, lower the voltage, higher the current drawn and higher the voltage drop. The current drawn is inversely proportional to the voltage level for the same quantity of power handled.

The power loss in line is proportional to resistance and square of current. (i.e. $P_{\text{Loss}} = I^2 R$). Higher voltage transmission and distribution thus would help to minimize line voltage drop in the ratio of voltages, and the line power loss in the ratio of square of voltages. For instance, if distribution of power is raised from 11 kV to 33 kV, the voltage drop would be lower by a factor $1/3$ and the line loss would be lower by a factor $(1/3)^2$ i.e., $1/9$. Lower voltage transmission and distribution also calls for larger quantity of conductor on account of current handling capacity needed.



Primary Grid System (as on June 2017)

Cascade Efficiency

Map not to scale

The primary function of transmission and distribution equipment is to transfer power economically and reliably from one location to another. Conductors in the form of wires and cables strung on towers and poles carry the high-voltage, AC electric current. A large number of copper or aluminum conductors are used to form the transmission path. The resistance of the long-distance transmission conductors is to be minimized. Energy loss in transmission lines is wasted in the form of I^2R losses.

Capacitors are used to correct power factor by causing the current to lead the voltage. When the AC currents are kept in phase with the voltage, operating efficiency of the system is maintained at a high level.

Circuit-interrupting devices are switches, relays, circuit breakers, and fuses. Each of these devices is designed to carry and interrupt certain levels of current. Making and breaking the current carrying conductors in the transmission path with a minimum of

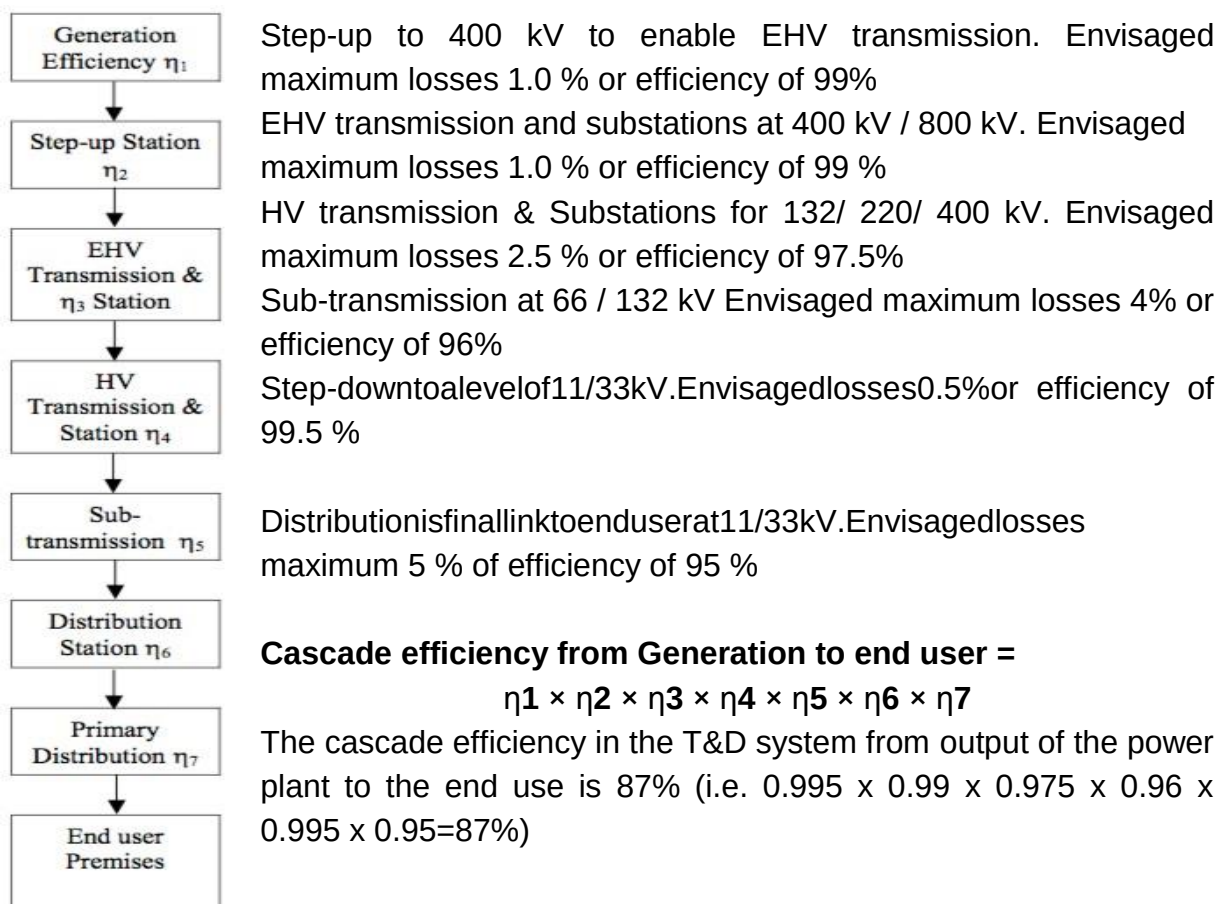
arcing is one of the most important characteristics of this device. Relays sense abnormal voltages, currents, and frequency and operate to protect the system.

Transformers are placed at strategic locations throughout the system to minimize power losses in the T&D system. They are used to change the voltage level from low-to-high in step-up transformers and from high-to-low in step-down units. Since the power loss of a transmission line is based on I^2R , losses can be reduced to are as on able value by stepping up the source voltage to a high value to proportionally reduce the source current.

The power source to end user energy efficiency link is a key factor which influences the energy input at the source of supply, consider the electricity flow from generation to the user in terms of cascade energy efficiency.

A typical cascade efficiency profile from Generation to 11 – 33 kV user industry is illustrated below:

Weighted efficiency for various mix of power generation sources viz. (Combined Cycle, Reciprocating Engine, Steam turbine and Gas Turbine) ranges 40-45 % w.r.t. size plant, vintage of plant and capacity utilization.



Industrial End User

At the industrial end user premises again the plant network elements like transformers at receiving sub-station, switch gear, lines and cables, load-break switches, capacitors cause losses which affect the input received energy.

A typical plant single line diagram of electrical distribution system is shown in Figure1.5

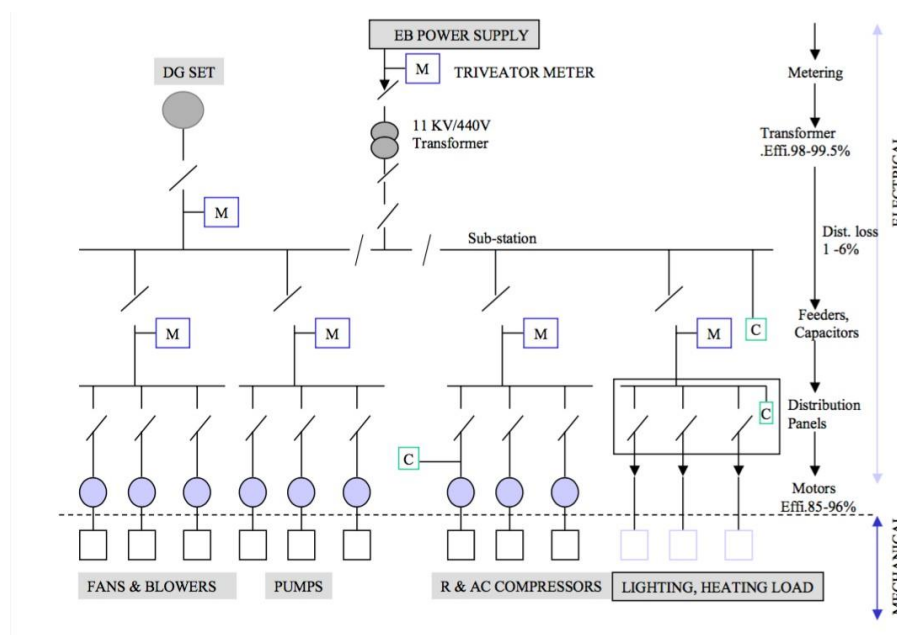


Figure 1.5: Electrical Distribution System – Single Line Diagram

The likely network elements that are encountered at industry–upto the motor, i.e., pre-motor system can include.

- Outdoor circuit breakers with typical full load losses % of 0.002 – 0.015%
- Receiving transformers with typical operating efficiency of 99 % or above.
- Medium voltage switch gear 5.15kV where maximum full load losses can be between 0.005 to 0.02%
- Load break switches where maximum of full load losses can be between 0.003–0.025 %.
- Current limiting reactors can have a maximum full load losses ranging from 0.09% to 0.3 %.
- Medium voltage starters can have a maximum full load losses of 0.02 % to 0.15 %.
- Lines and cables can have a maximum loss ranging for 1 % to 6 % depending upon lengths, voltage levels, power factor, condition of network in plant

- Motor control centers can have a full load losses range from 0.01% to 0.4 %.
 - Low voltage switchgear can have a full load loss ranging from 0.13 % to 0.34 %.
- Thus, as per the links available in the in-plant distribution network, the cascade efficiency of pre-motor system can be computed, as a product of efficiencies of the actual links in cascade.
- When problems like low voltage at motor terminals are encountered, this pre-motor system needs to be looked into, for improvement opportunities like;
- Relocating transformers close to load centers.
 - Increasing cable / line size addition of parallel cable, and minimizing jumpers / loose connections and optimizing line lengths etc.
 - Tap changing as needed at the transformers.
 - Capacitor relocation close to load centers or motor terminals, as discussed later.
 - Adopting best practices like infrared thermograph of distribution network, for identifying hotspots, which indicate potential are as of break-down/overloading etc., for attention / maintenance.

ONE Unit saved = TWO Units Generated

After power generation at the plant, it is transmitted and distributed over a wide network. The standard technical losses are around 9.5% in Bangladesh (Efficiency=90.5%). But overall T & D (Transmission and Distribution Loss) losses range from 9 –17%. All these may not constitute technical losses, since un-metered and pilferage are also accounted in this loss.

When the power reaches the industry, it is received by the transformer. The energy efficiency of the transformer is generally very high. Next it goes to the motor through internal plant distribution network. A typical distribution network efficiency including transformer is 95% and motor efficiency is about 90%. Another 30% (Efficiency=70%) is lost in the mechanical system which includes coupling / drive train, a driven equipment such as pump and flow control valves/throttling etc. Thus the overall energy efficiency becomes 50%. ($0.90 \times 0.95 \times 0.9 \times 0.70 = 0.54$, i.e 54% efficiency)

Hence one unit saved in the end user is equivalent to two units generated in the power plant. ($1 \text{ Unit} / 0.5 \text{ Eff} = 2 \text{ Units}$)

1.2. Electricity billing

The electricity billing by utilities for medium & large industries and enterprises (Category - F to Category – H) is often done on two-part tariff structure, i.e. one part for capacity (or demand) drawn and the second part for actual energy drawn during the billing cycle. Capacity or demand is in kW. There active energy (i.e.) kVARH

drawn by the customer / service is also recorded and billed for in some utilities, because this would affect the load on the utility. Accordingly, utility charges for maximum demand, active energy and reactive power drawn as reflected by the power factor in their billing structure. In addition, other fixed and variable expenses are also levied.

The tariff structure generally includes the following components:

a) *Maximum demand Charges*

These relate to maximum demand registered during month / billing period and corresponding rate of utility.

b) *Energy Charges*

These relate to energy (kilo watt hours) consumed during month /billing period and corresponding rates, often levied in slabs of use rates. Some utilities now charge on the basis of apparent energy (kVAh), which is a vector sum of kWh and kVARh.

c) *Power factor* penalty or bonus rates, as levied by most utilities, are to contain reactive power drawl from grid.

d) *Fuel cost* adjustment charges as levied by some utilities are to adjust the increasing fuel expenses over a base reference value.

e) *Electricity duty charges* levied w.r.t units consumed.

f) *Meter rentals*

g) *Lighting and fan power consumption* is often at higher rates, levied sometimes on slab basis or on actual metering basis.

h) *Interruptible and adjustable rates* like night tariff concessions and time of use rates are also prevalent in tariff concessions and time of use rates are also prevalent in tariff structure provisions of some utilities.

“Analysis of utility bill data and trending of the same helps energy manager to identify ways for electricity bill reduction through available provisions in tariff framework, apart from budgeting”.

The utility employs a tri vector meter of electromagnetic or the state of the art static electronic tri vector meter, for billing purposes. As apparent, active and reactive energy are vectorial in nature, the monitoring meter is called Tri vector meter. The minimum outputs from the electromagnetic meters are:

- Maximum demand registered during the month, which is measured in preset time intervals (say of 30 minute duration) and this is reset at the end of every billing cycle.
- Maximum demand (MD) in kW shall be registered using the technique of cumulating on integration period controlled by built-in process and the MD shall

be continuously recorded and the highest shall be indicated. (Integration period: thirty minutes)

- Active energy in KWH during billing cycle
- Average PF for billing period.
- Reactive energy in KVARH during billing cycle and
- Apparent energy in KVAH during billing cycle

It is important to note that while maximum demand is recorded, it is not the instantaneous demand drawn, as is often understood, but the time integrated demand over the predefined recording cycle.

As example, in an industry, if the drawl over a recording cycle of 30 minutes is:

- 2500 KW for 4 minutes
- 3600 KW for 12 minutes
- 4100 KW for 6 minutes
- 3800 KW for 8 minutes

The MD recorder will be computing MD as:

$$\frac{(2500 \times 4) + (3600 \times 12) + (4100 \times 6) + (3800 \times 8)}{30} = 3606.7 \text{ kW}$$

The month's maximum demand will be the highest among such demand values recorded over the month. The meter registers only if the value exceeds the previous maximum demand value and thus, even if, average maximum demand is low, the industry/facility has to pay for the maximum demand charges for the highest value registered during the month, even if it occurs for just one recording cycle duration i.e., 30 minutes during whole of the month (1440 such intervals in a month).

The LCD electronic tri-vector meters have some excellent provisions that can help the utility as well as the industry. These provisions include:

- Substantial memory for logging and recording all relevant events
- High accuracy of 0.2 class
- Amenability to time of use tariffs
- Tamper detection /recording
- Measurement of harmonics and Total Harmonic Distortion (THD)
- Long service life due to absence of moving parts
- Amenability for remote data access/downloads

Analysis and trending of purchased electricity for the past 12 months in a year and cost components can help the industry to identify key areas such as a voiding power factor penalty, contract demand reduction and availing time of the tariff advantages

etc. for bill reduction within the utility tariff available framework.

Compiling monthly electricity use data, including all sources like; cogeneration, captive diesel power generation; doing cost comparison by source, linking power consumption to production by specific power consumption assessment, would serve as a powerful information tool for energy manager / auditor to optimize electricity costs for the industry or facility.

1.3. Electrical load management and maximum demand control

Need for Electrical load management

1. In a macro perspective, the growth in the electricity use and diversity of end use segments in time of use has led to shortfalls in capacity to meet demand. As capacity addition is costly and only a long time prospect, better load management at user end helps to minimize peak demands on the utility infrastructure as well as better utilization of plant capacities.
2. The utilities use power tariff structure to influence end user in better load management through measures like time of use tariffs, penalties on exceeding allowed maximum demand, night tariff concessions etc. Load management is a powerful means of efficiency improvement both for end user as well as utility.
3. As the demand charges constitute a considerable portion of the electricity bill, from user angle too there is a need for integrated load management to effectively control the maximum demand.

Step By Step Approach for Maximum Demand Control

1. Load Curve Generation

Presenting the load demand of a consumer against time of the day is known as a 'load curve'. If it is plotted for the 24 hours of a single day, it is known as an 'hourly load curve' and if daily demands plotted over a month, it is called daily load curves. These types of curves are useful in predicting patterns of drawl, peaks and valleys and energy use trend in a section or in an industry or in a distribution network as the case may be.

The load factor can also be defined as the ratio of the energy consumed during a given period to the energy, which would have been used if the maximum demand had been maintained throughout that period.

Load Factor = (Energy Consumed in 24 Hours) / (Maximum Load Recorded × 24 Hours).

2. Rescheduling of Loads

Rescheduling of large electric loads and equipment operations, in different shifts can be planned and implemented to minimize the simultaneous maximum demand. For this purpose, it is advisable to prepare an operation flow chart and a process chart. Analyzing these charts and with an integrated approach, it would be possible to reschedule the operations and running equipment in such away as to reduce the maximum demand and improve the load factor.

3. Staggering of Motor loads

When running of motors of large capacities are involved, it is advisable to stagger the running of these motors with a suitable planning (as the process may permit) so as to minimize the simultaneous maximum demand (depending on the conditions of load) offered by these motors.

4. Storage of Products/in process material/ process utilities like refrigeration

It is possible to reduce the maximum demand by building up storage capacity of products/ materials, water, chilled water / hot water using electricity during off peak periods. Off peak hour operations also help to save energy due to favorable conditions such as lower ambient temperature etc.

Example: Ice bank system is used in milk & dairy industry. Ice is made in lean period and used in peak load period and thus maximum demand is reduced.

Shedding of Non-Essential Loads

When the maximum demand tends to reach preset limit, shedding some of non-essential loads temporarily can help to reduce it. It is possible to install direct demand monitoring systems, which will switch off non-essential loads when a preset demand is reached. Simple systems give an alarm, and the loads are shed manually. Sophisticated microprocessor controlled systems are also available, which provide a wide variety of control options like:

- Accurate prediction of demand
- Graphical display of present load, available load, demand limit
- Visual and audible alarm
- Automatic load shedding in a predetermined sequence
- Automatic restoration of load
- Recording and metering

5. Operation of Captive Generation, Diesel Generation Sets and Gas Engines

When Diesel/Gas generation sets are used to supplement the power supplied by the electric utilities, it is advisable to connect the Diesel or Gas sets for durations when demand reaches the peak value. This would reduce the load demand to a considerable extent and minimize the demand charges.

6. Reactive Power Compensation

The maximum demand can also be reduced at the plant level by using capacitor banks and maintaining the optimum power factor. Capacitor banks are available with microprocessor based control systems. These systems switch on and off the capacitor banks to maintain the desired Power factor of system and optimize maximum demand thereby.

1.4. Power factor improvement and benefits

Power factor Basics

In all industrial electrical distribution systems, the pre dominant loads are resistive and inductive. Resistive loads are incandescent lighting and resistance heating. In case of pure resistive loads, the voltage (V), current (I), resistance (R) relations are linearly related, i.e.

$$V = I \times R \text{ and } kW = V \times I$$

Inductive loads are A.C. Motors, induction furnaces, transformers and ballast-type lighting. Inductive loads require two kinds of power: (1) active (or working) power to perform the work and (2) reactive power to create and maintain electro-magnetic fields. The vector sum of the active power and reactive power make up the total (or apparent) power used. This is the power generated by the Utilities (Distribution companies) for the user to perform a given amount of work.

- Active power is measured in KW (Kilo Watts)
- Reactive power is measured in KVAR (Kilo Volt-Amperes Reactive)
- Total Power is measured in KVA (Kilo Volts-Amperes)

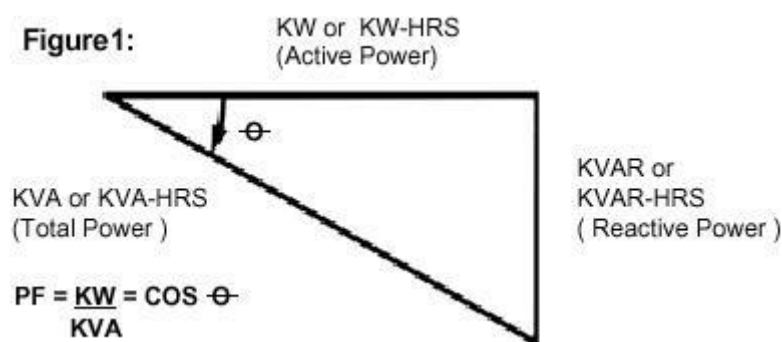


Figure 1.6: Power factor

The active power (shaft power required or true power required) in kW and the reactive power required (kVAr) are 90° apart vectorically in a pure inductive circuit i.e., reactive power kVAR lagging the active kW. The vector sum of the two is called the apparent power or kVA, as illustrated above and the kVA reflects the actual electrical load on distribution system.

The ratio of kW to kVA is called the power factor which is always less than or equal to unity. Theoretically, when electric utilities supply power, if all loads have unity power factor, maximum power can be transferred for the same distribution system capacity. However, as the loads are inductive in nature with the power factor ranging from 0.2 to 0.9, the electrical distribution network is stressed for capacity at low power factors.

Improving Power Factor

The solution to improve the power factor is to add power factor correction capacitors to the plant power distribution system. They act as reactive power generators, and provide the needed reactive power to accomplish KW of work. This reduces the amount of reactive power and thus total power generated by the Utilities (Distribution companies)

Example:

A chemical industry had installed a 1500KVA transformer. The initial demand of the plant was 1160KVA with power factor of 0.70. The % loading of transformer was about 78% ($1160/1500=77.3\%$). To improve the power factor and thereby avoiding the penalty, the unit had added about 410KVAR in motor load end. This improved the power factor to 89%, and reduced the required KVA to 913, which is the vector sum of KW and KVAR.

After improvement the plant had avoided penalty and the 1500KVA transformer now loaded only to 60% of capacity. This will allow the addition of more loads in the future to be supplied by the transformer.

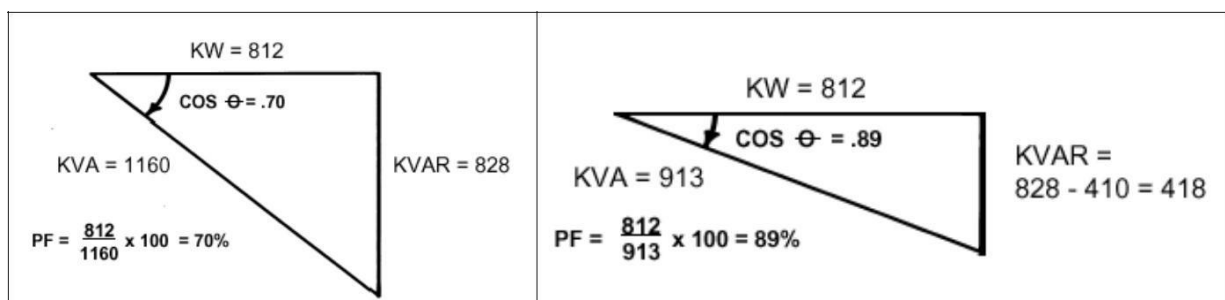


Figure 1.7a: Power factor before and after Improvement

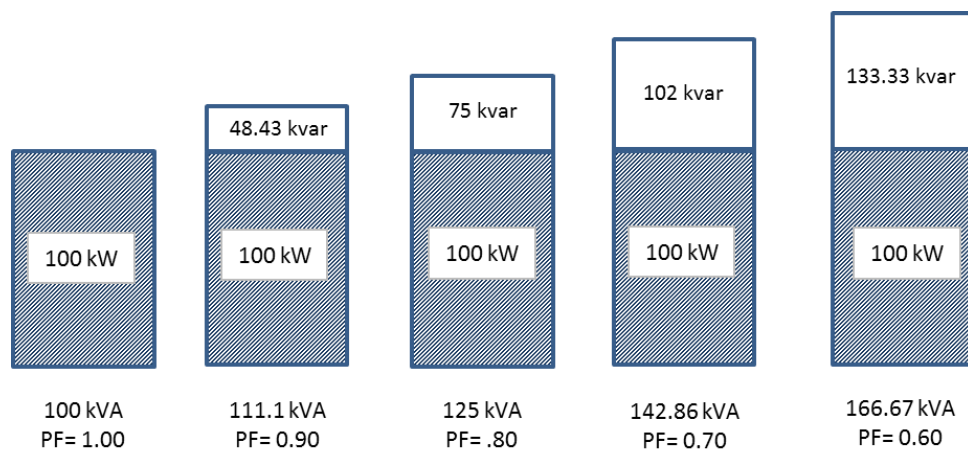


Figure 1.7b: Increase in the apparent and reactive powers as a function of the load power factor, holding the real power of the load constant

The advantages of improvement by capacitor addition

- Reactive component of the network is reduced and also the total current in the system from the source end.
- I^2R power losses are reduced in the system because of reduction in current.
- Voltage level at the load end is increased.
- KVA loading on the source generators as also on the transformers and lines up to the capacitors reduces giving capacity relief. A high power factor can help in utilizing the full capacity of the electrical system.

Cost benefits of PF improvement

While costs of PF improvement are in terms of investment needs for capacitor addition the benefits to be quantified for feasibility analysis are:

- Reduced KVA (Maximum demand) charges in utility bill
- Reduced distribution losses (KWH) within the plant network
- Better voltage at motor terminals and improved performance of motors
- A high power factor eliminates penalty charges imposed when operating with a low power factor
- Investment on system facilities such as transformers, cables, switchgears etc. for delivering load is reduced

Selection, Location and Sizing of Capacitor

The figures given in table 1 are the multiplication factors which are to be multiplied with the input power (kW) to give the kVAr of capacitance required to improve present power factor to a new desired power factor.

Table 1.1: Multiplication factors for selection of capacitors

Original P.F.	Desired P.F.				
	1.0	0.95	0.90	0.85	0.80

0.55	1.518	1.189	1.034	0.899	0.763
0.60	1.333	1.004	0.849	0.714	0.583
0.65	1.169	0.840	0.685	0.549	0.419
0.70	1.020	0.691	0.536	0.400	0.270
0.75	0.882	0.553	0.398	0.262	0.132
0.80	0.750	0.421	0.266	0.130	
0.85	0.484	0.291	0.136		
0.90	0.328	0.155			
0.95	0.620				

Having known the existing power factor, the multiplication factor may be calculated for raising the power factor from the present value to the desired value.

Example

If power factor of 30 kW load is to be improved from 0.80 to 0.95, then

Size of the capacitor = kW × multiplication factor

30×0.421

12.63 (or) 13 kVAr

In case of induction motors of different ratings and speeds, in order to improve their power factor to 0.95 and above, the rating of the capacitor (in kVAr) for direct connection to induction motor can be referred to in the chapter on electric motors.

Direct relation can also be used for capacitor sizing

$$\text{KVAR Rating} = \text{KW} [\tan \phi_1 - \tan \phi_2]$$

where, KVAR rating is the size of the capacitor needed, KW is the average power drawn, $\tan \phi_1$ is the trigonometric ratio for the present power factor, and $\tan \phi_2$ is the trigonometric ratio for the desired PF.

$$\phi_1 = \text{Existing } (\cos^{-1} \text{PF}_1) \text{ and } \phi_2 = \text{Improved } (\cos^{-1} \text{PF}_2)$$

Location of Capacitors

Location of capacitors is an important factor to be considered. For the benefit of electricity boards, connection of capacitors on H.T. side is good enough. Although the cost of H.T. capacitor per kVAr is low, the cost of the associated switchgear is quite high.

Alternatively, the capacitors can be connected on L.T. side of the main substation. The capacitors may be placed at load centers viz., directly with motors or group of motors at motor control centers. Correction of PF at the motors has number of advantages, as the induction motors are the main source of reactive currents in every industrial plant. The advantages include the absence of additional switchgear;

no separate control of capacitor is required in switching on and off operations and reduced effect of motor inrush currents.

From energy efficiency point of view, capacitor location at receiving substation only helps the utility in loss reduction. Locating capacitors at user end motors will help to reduce loss reduction within the plants distribution network as well and directly benefit the user by reduced demand cost. Reduction in the distribution loss in KWH when tail end power factor is raised from PF1 to a new power factor PF2, will be proportional to $[1 - (PF_1 / PF_2)^2]$

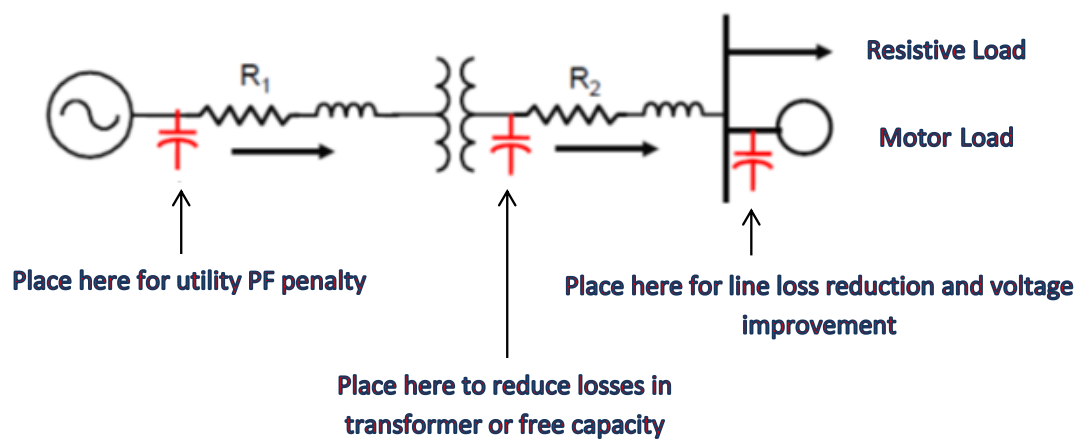


Figure 1.8: Effect of Location

Capacitors for other loads

The other types of load requiring capacitor application include induction furnaces, induction heaters, arc welding transformers etc. The capacitors are normally supplied with control gear for the application of induction furnaces and induction heating furnaces. The P.F of arc furnaces experiences a wide variation over melting cycle as it changes from 0.7 at starting to 0.9 at the end of the cycle.

Power factor for arc welders and resistance's welders is corrected by connecting capacitors across the primary winding of the transformers, as the normal PF would be in the range of 0.35. There commended capacitor ratings for various sizes of welding transformers are given in table below.

Welding Transformer Rating kVA	Capacitor Rating kVAR
Single Phase	
9	4
12	6
18	8
24	12
30	18
Three Phase	

57	16.5
95	30
128	45
160	60

Performance assessment of power factor capacitors

Voltage effects: Ideally capacitor voltage rating is to match the supply voltage. If the supply voltage is lower, the reactive KVAR produced will be the ratio V_1^2/V_2^2 where V_1 is the actual supply voltage, V_2 is the rated voltage.

On the other hand, if the supply voltage exceeds rated voltage, the life of the capacitor is adversely affected.

kVAR Added	Phase Voltage	Phase Current	Total (kW)	Total (kVA)	Power Factor
0	269	121	69	96	0.72
15	268	109	69	84	0.8
30	270	100	70	80	0.87
45	271	92	70	74	0.94
60	272	88	70	71	0.98
75	273	87	70	70	0.99
90	274	89	70	73	0.95 (1.05)
105	276	95	70	79	0.89 (1.11)

Table 1.2: Effect of addition of kVAR capacitor

Material of capacitors: Power factor capacitors are available in various types by dielectric material used as; paper/poly propylene etc. The watt loss per kVAR as well as life vary with respect to the choice of the dielectric material and hence is a factor to be considered while selection.

Connections: Shunt capacity or connections are adopted for almost all industry/end user applications, while series capacitors are adopted for voltage boosting in distribution networks.

Operational performance of capacitors: This can be made by monitoring capacitor charging current vis- a- vis the rated charging current. Capacity of fused elements can be replenished as per requirements. Portable analyzers can be used for measuring kVAR delivered as well as charging current.

Some checks that need to be adopted in use of capacitors are:

- Nameplates can be misleading with respect to ratings. It is good to check by charging currents.
- Capacitors boxes may contain only insulated compound and insulated terminals

with no capacitor elements inside.

- iii. Capacitors for single phase motor starting and those used for lighting circuits for voltage boost, are not power factor capacitor units and these cannot stand power system conditions.

1.5. Transformers

A transformer can accept energy at one voltage and deliver it at another voltage. This permits electrical energy to be generated at relatively low voltages and transmitted at high voltages and low currents, thus reducing line losses.

Transformers consist of two or more coils that are electrically insulated, but magnetically linked. The primary coil is connected to the power source and the secondary coil connects to the load. The turn's ratio is the ratio between the number of turns on the primary to the turns on the secondary.

The secondary voltage is equal to the primary voltage times the turn's ratio. Ampere-turns are calculated by multiplying the current in the coil times the number of turns. Primary ampere-turns are equal to secondary ampere-turns. Voltage regulation of a transformer is the percent increase in voltage from full load to no load.

Types of Transformers

Transformers are classified as two categories as given below:

Power transformers: It is used in transmission network of higher voltages, deployed for step-up and step down transformer application. (400 kV, 200 kV, 110kV, 66kV, 33kV)

Distribution transformers: It is used for lower voltage distribution networks as a means to end user connectivity. (11.kV, 6.6kV, 3.3kV, 440V, 230V)

Rating of transformer

Rating of the transformer is calculated based on the connected load and applying the diversity factor on the connected load, applicable to the particular industry and arrive at the KVA rating of the Transformer. Diversity factor is defined as the ratio of overall maximum demand of the plant to the sum of individual maximum demand of various equipment. Diversity factor varies from industry to industry and depends on various factors such as individual loads, load factor and future expansion needs of the plant. Diversity factor will always be less than one.

Location of transformer

Location of the transformer is very important as far as distribution loss is concerned. Transformer receives HT voltage from the grid and steps it down to the required voltage. Transformers should be placed close to the load centre, considering other features like optimization needs for centralized control, operational flexibility etc. This will bring down the distribution loss in cables.

Transformer Losses and Efficiency

The efficiency varies anywhere between 96 to 99 percent. The efficiency of the transformers not only depends on the design but also on the effective operating load. Transformer losses consist of two parts.

No-load loss (also called core loss) is the power consumed to sustain the magnetic field in the transformer's steel core. Core losses are caused by two factors: hysteresis and eddy current losses. Hysteresis loss is that energy lost by reversing the magnetic field in the core as the magnetizing AC rises and falls and reverses direction. Eddy current loss is a result of induced currents circulating in the core. Core loss occurs whenever the transformer is energized; core loss does not vary with load.

Load loss (also called copper loss) is associated with full-load current flow in the transformer windings. Copper loss is power lost in the primary and secondary windings of a transformer due to the ohmic resistance of the windings. Copper loss varies with the square of the load current. ($P = I^2 R$).

For a given transformer, the manufacturer can supply values for no-load loss, $P_{NO-LOAD}$, and load loss, P_{LOAD} . The total transformer loss, P_{TOTAL} , at any load level can then be calculated from:

$$P_{TOTAL} = P_{NO-LOAD} + (\% \text{ Load}/100)^2 \times P_{LOAD}$$

Where transformer loading is known, the actual transformer's loss at given load can be computed as:

$$\text{No load loss} + \left(\frac{\text{KVA Load}}{\text{Rated KVA}} \right)^2 \text{ full load loss}$$

Table 1.3: Typical Transformer Loss for Distribution Transformers(DT's) above 100kVA

KVA Rating	Voltage Rating	No load loss(W)	Load Loss(W)	Impedance%
160		425	3000	5
200		570	3300	5
250		620	3700	5

315	11000/433	800	4600	5
500		1100	6500	5
630		1200	7500	5
1000		1800	11000	5
1600		2400	15500	5
2000	33000/433	3000	20000	6
630		1450	7500	5
1000		2200	11500	5
1600		3000	16000	6.25
2000		3500	21000	6.25

Voltage fluctuation control

A control of voltage in a transformer is important due to frequent changes in supply voltage level. Whenever the supply voltage is less than the optimal value, there is a chance of nuisance tripping of voltage sensitive devices. The voltage regulation in transformers is done by altering the voltage transformation ratio with the help of tapping. There are two methods of tap changing facility available.

Off-circuit tap changer

It is a device fitted in the transformer, which is used to vary the voltage transformation ratio. Here the voltage levels can be varied only after isolating the primary voltage of the transformer.

On load tap changer (OLTC)

The voltage levels can be varied without isolating the connected load to the transformer. To minimise the magnetization losses and to reduce the nuisance tripping of the plant, the main transformer (the transformer that receives supply from the grid) should be provided with On Load Tap Changing facility at design stage. The downstream distribution transformers can be provided with off-circuit tap changer.

The On-load gear can be put in auto mode or manually depending on the requirement. OLTC can be arranged for transformers of size 250kVA onwards. However, the necessity of OLTC below 1000 kVA can be considered after calculating the cost economics.

Parallel operation of transformers

The design of Power Control Centre (PCC) and Motor Control Centre (MCC) of any new plant should have the provision of operating two or more transformers in parallel. Additional switch gears and bus couplers should be provided at design stage.

Whenever two transformers are operating in parallel, both should be technically

identical in all aspects and more importantly with same impedance level. This will minimise the circulating current between transformers.

Where the load is fluctuating in nature, it is preferable to have more than one transformer running in parallel, so that the load can be optimized by sharing the load between transformers. The transformers can be operated close to the maximum efficiency range by this operation.

Energy Efficient Transformers

Most energy loss in dry-type transformers occurs through heat or vibration from the core. The new high-efficiency transformers minimize these losses. The conventional transformer is made up of a silicon alloyed iron (grain oriented) core. The iron loss of any transformer depends on the type of core used in the transformer. The latest technology is to use for the amorphous core. Amorphous material has great advantage in reducing No load loss.

Amorphous core material (AM) offers both reduced hysteresis loss and eddy current loss because this material has a random grain and magnetic domain structure which results in high permeability giving a narrow hysteresis curve compared to conventional core material. Eddy current losses are reduced by the high resistivity of the amorphous material, and the reduced thickness of the film (thickness is approximately 0.03 mm, which is about 1/10 comparing with silicon steel). Amorphous core transformers offer a 70 to 80% reduction in no-load losses compared to transformers using conventional core material.

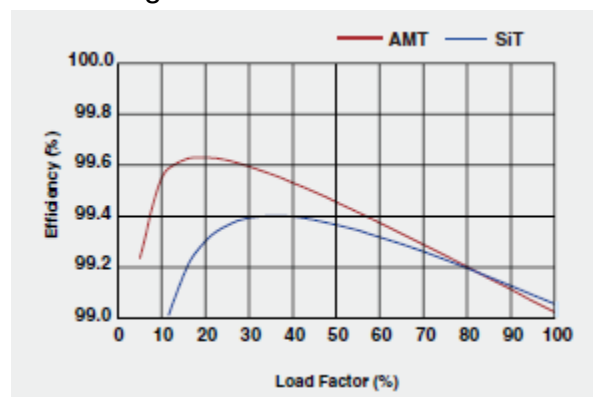


Figure 1.9: Comparison of Conventional and Amorphous Core Transformers

Example: Transformer loss calculation

An engineering industry has installed three numbers of 1000KVA transformers for an electrical load of 1500KVA. The No-load loss and the full load loss of the transformers were collected from the transformer certificates as 2.8KW and 11.88KW respectively. Estimate the total loss when 3 transformers in parallel

operation and also 2 transformers parallel operation. The transformer losses can also be obtained from manufacturers test certificate which are available in the plant.

a) Total loss when Two transformers in parallel operation:

No load loss = $2 \times 2.8 = 5.6$

Load Loss = $2 \times (750/1000)^2 \times 11.88$

Total Loss = $5.6 + 13.36 = 18.96$

b) Total loss when Three transformers in parallel operation: No load loss = $3 \times 2.8 = 8.4 \text{ kW}$

Load loss = $3 \times (500/1000)^2 \times 11.88 = 8.91 \text{ kW}$

Total loss = 17.31 kW

Savings by operating 3 transformers in parallel

= $18.96 - 17.31 = 1.65 \text{ kWh}$

= $1.65 \text{ kWh} \times 24 \text{ Hrs} \times 365 \text{ days} = 14454 \text{ kWh /year}$

1.6. System distribution losses

In an electrical system often the constant no load losses and the variable load losses are to be assessed alongside, over long reference duration, towards energy loss estimation.

Identifying and calculating the sum of the individual contributing loss components is a challenging one, requiring extensive experience and knowledge of all the factors impacting the operating efficiencies of each of these components.

For example the cable losses in any industrial plant will be of the order of 2 to 4 percent. Note that all of these are current dependent, and can be readily mitigated by any technique that reduces facility current load.

In system distribution loss optimization, the various options available include:

- Relocating transformers and sub-stations near to load centers
- Re-routing and re-conducting such feeders and lines where the losses/voltage drops are higher.
- Power factor improvement by incorporating capacitors at load end.
- Optimum loading of transformers in the system.
- Opting for lower resistance All Aluminum Alloy Conductors (AAAC) in place of conventional Aluminum Cored Steel Reinforced (ACSR) lines
- Minimizing losses due to weak links in distribution networks such as jumpers, loose contacts, old brittle conductors.
- Distribution loss assessment and optimization studies today are feasible on account of accurate metering developments on the one hand and availability of

powerful computer based load flow analysis packages on the other.

- Using full infrared thermography system, each electrical panel can be scanned to identify points of high system heat. Called “hotspots,” these high heat points result from connections become looser corroded overtime. The resulting increase in resistance at that’s pot in the system can add wattage losses to the electrical energy consumption. These hot spots also create safety risks and risks to abrupt system failure. Fixing them is often as simple as de-energizing that point in the system, and then using a wrench to tighten a bolt.

As far as electricity distribution utilities are concerned, involving large network and complex connectivity features, there exist well proven computer based application packages which can be used for network load flow analysis. The analysis outputs can help a utility engineer to assess the extent of transmission and distribution losses, to identify sections for improvement where voltage drops are high, to identify avenues for loss reduction such as ideal location of sub-stations, feeder augmentation, etc.

1.7. Harmonics and its Effects

In any alternating current network, flow of current depends upon the voltage applied and the impedance (resistance to AC) provided by elements like resistances, reactance of inductive and capacitive nature. As the value of impedance in above devices is constant, they are called linear whereby the voltage and current relation is of linear nature.

Example for Linear loads

Linear loads occur when the impedance is constant; then the current is proportional to the voltage (A straight – line graph, as shown in Figure–1.10). Simple loads, composed of one of the elements shown in Figure–1.10, do not produce harmonics.

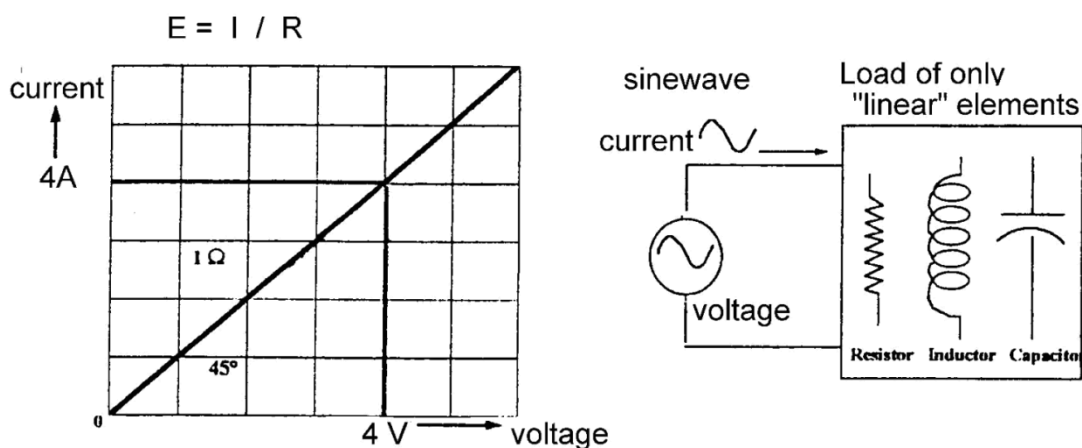


Figure 1.10: Linearloads

However in real life situation, various devices liked diodes, silicon controlled rectifiers, thyristors, voltage & current controllers, induction & arc furnaces are also deployed for various requirements and due to their varying impedance characteristic, these Non-Linear devices cause distortion in voltage and current waveforms which is of increasing concern in recent times.

Example for Non-Linear loads

Non-linear loads occur when the impedance is not constant; then the current is not proportional to the voltage (as shown in Figure 1.11. Combinations of the components shown in Figure 1.11 normally create non-linear loads and harmonics.

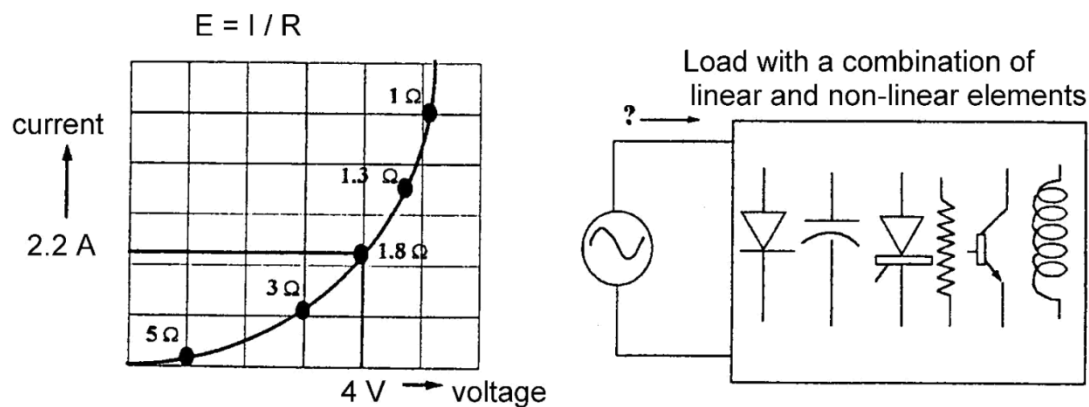


Figure 1.11: Non-Linear loads

Harmonics occurs as spikes at intervals which are multiples of the mains (supply) frequency and these distort the pure sine wave form of the supply voltage & current. Thus harmonics are multiples of the fundamental frequency of an electrical power system. If for example, the fundamental frequency is 50Hz, then the 5th harmonic is five times that frequency, or 250 Hz. Likewise, the 7th harmonic is seven times the fundamental or 350Hz, and so on for higher order harmonics.

The magnitude and order of harmonics is governed by the nature of the device being used and the impact is expressed as Total Harmonic Distortion (THD). Harmonics can be expressed in terms of current or voltage

In terms of voltage it is expressed as a percentage of fundamental voltage by the expression

$$\%THD = \sqrt{\sum_{n=2}^{n=\infty} \frac{V_n^2}{V_1^2}} * 100$$

where V_1 is the fundamental frequency voltage and V_n is n^{th} harmonic voltage component.

In terms of current it is expressed as below

A 5th harmonic current is simply a current flow in at 250Hz on a 50Hz system. The 5th harmonic current flowing through the system impedance creates a 5th harmonic voltage. The following is the formula for calculating the THD for current:

$$= \frac{\sqrt{(I_5^2 + I_7^2)}}{I_1}$$

I_1 = current at 50 Hz = 250 Amps, I_5 = current at 250 Hz = 50 Amps I_7 = current at 350 Hz = 35 Amps

If I_1 = 250 Amps, I_5 = 50 Amps and I_7 = 35 Amps

Then...

$$I_{THD} = \frac{\sqrt{(50^2 + 35^2)}}{250} \times 100 = 24\%$$

When harmonic currents flow in a power system, they are known as poor “power quality”. Other causes of poor power quality include transients such as voltage spikes, surges, sags, and ringing. Because they repeat every cycle, harmonics are regarded as a steady-state cause of poor power quality.

The harmonic assessment can be carried out at site by using a load analyzer. The wave form is sampled and analyzed across various harmonic frequencies, i.e. multiples of the mains frequency for assessing THD. Load analyzers are available in market, which can measure THD up to 63rd harmonic.

Causes and Effects of Harmonics in electrical systems

Devices that draw non-sinusoidal currents when a sinusoidal voltage is applied create harmonics. Frequently these are devices that convert AC to DC. Listed below are some of these devices.

Electronic Switching Power Converters

- Computers, Uninterruptible power supplies (UPS), Solid-state rectifiers
- Electronic process control equipment, PLC's, etc.
- Electronic lighting ballasts, including light dimmer
- Reduced voltage motor controllers

Arcing Devices

- Discharge lighting, e.g. Fluorescent, Sodium and Mercury vapor
- Arc furnaces, Welding equipment, Electrical traction system

Ferromagnetic Devices

- Transformers operating near saturation level
- Magnetic ballasts (Saturated Iron core)
- Induction heating equipment, Chokes, Motors

Appliances

- TV sets, air conditioners, washing machines, microwave ovens
- Fax machines, photocopiers, printers

These devices use power electronics like diodes and thyristors which are a growing percentage of the load in industrial power systems. Normally each load would manifest a specific harmonic spectrum. Many problems can arise from harmonic currents in a power system. Some problems are easy to detect. Higher RMS current and voltage in the system are caused by harmonic currents, which can result in any of the problems listed below.

Effects of Harmonics on Network

The effects of harmonics on distribution network include:

- Metering errors in electromagnetic type meters.
- Overloading and overheating of motors due to increased iron losses & overheating of conductors.
- Overloading of neutral conductor especially in low voltage distribution network and High neutral currents
- Malfunctioning of control equipment and protection relays due to false signals.
- Blown Fuses (no apparent fault)
- Misfiring of AC and DC Drives
- Tripped Circuit Breakers Voltage distortion
- High neutral to ground voltages Increased system losses (heat)
- Rotating and electronic equipment failures
- Capacitor bank over-load and failures
- Reduced power factor

Source	Typical Harmonics
6 Pulse Drive/Rectifier	5,7,11,13,17,19...
12 Pulse Drive/Rectifier	11,13,23,25...
18 Pulse Drive	17,19,35,37...
Switch-Mode Power Supply	3,5,7,9,11,13...
Fluorescent Lights	3,5,7,9,11,13...
Arcing Devices	2,3,4,5,7...
Transformer Energization	2,3,4

Generally, the magnitude decreases as harmonic order increases.

$$H = NP \pm 1$$

h = order of harmonics, n = an integer 1, 2, 3, ..., p = number of pulses per cycle
For a three phase bridge rectifier, since the number of pulses $p = 6$ per line frequency cycle,
the characteristic or dominant harmonics are: $h = n \cdot 6 \pm 1 = 5, 7, 11, 13, 17, 19, 23, 25, 35,$

Harmonic Filters

Harmonic filters consist of a capacitor bank and reactor in series are designed and adopted for suppressing harmonics, by providing low impedance path for harmonic component. The Harmonic filters connected suitably near the equipment generating harmonics help to reduce THD to acceptable limits. In present context where no Electro Magnetic Compatibility regulations exist, an application of Harmonic filters is very relevant for industries having diesel power generation sets and co-generation units. Energy managers / auditors can address the issue of harmonics from the point of view of energy efficiency and power quality assurance.

The Harmonic Mitigation solutions currently in use in the industry broadly fall into the following categories:

1. Passive Harmonic Filter (PHF)
2. Advance Active Filters (AAF)
3. Active Front End based VFDs (AFE)

Passive Harmonic Filter (PHF)

It is the most common method for the cancellation of harmonic current in the distributed system. These filters are basically designed on principle either single tuned/double tuned or band pass filter technology. Passive filters (Figure 1.20) offer very low impedance in the network at the tuned frequency to divert all the harmonic current at the tuned frequency.

Advance Active Filters (AAF)

It is connected parallel with the distribution system. Distribution system consists of a wide percentage of harmonics produced by non- linear loads. Active filters (Figure 1.21) compensate current harmonics by injecting equal magnitude but opposite phase harmonic compensating current.

Active Front End based VFDs (AFE)

It is used in VFDs has the major advantage of mitigation of harmonics without using external filter, to maintain unity power factor at the point of common coupling,

Bidirectional power flow makes recovery of energy to the mains by saving it, Clean power to the grid which in turn does not affect the other loads connected to it, maintaining the DC voltage irrespective of the supply variations.

Harmonics Limits:

The permissible harmonic limit for different current (I_{sc} / I_L) as per IEEE standard is given in Table 1.4 and for different bus voltage are given in Table 1.5

Current Distortion Limits for General Distribution System's end-User limits (120 Volts To 69,000 Volts)

Table 1.4 Maximum Harmonic Current Distortion in % of I_L						
Individual Harmonic Order (Odd Harmonics)						
I_{sc}/I_L	<11	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h$	TDD
$< 20^*$	4.0	2.0	1.5	0.6	0.3	5.0
$20 < 50$	7.0	3.5	2.5	1.0	0.5	8.0
$50 < 100$	10.0	4.5	4.0	1.5	0.7	12.0
$100 < 1000$	12.0	5.5	5.0	2.0	1.0	15.0
> 1000	15.0	7.0	6.0	2.5	1.4	20.0
Even harmonics are limited to 25% of the odd current harmonic limits above.						
Current distortions that result in a direct current offset, e.g. half wave converters are not allowed.						
*All power generation equipment is limited to these values of current distortion, regardless of actual I_{sc}/I_L .						
Where, I_{sc} = Maximum short circuit current at PCC. And I_L = Maximum Demand Load Current (fundamental frequency component) at PCC. TDD = Total demand distortion (RSS), harmonic current distortion in % of maximum demand load current (15 or 30 min demand).						

Table 1.5 Total Harmonic Distribution for Different Voltage Levels in %		
Bus Voltage at PCC	Individual Voltage Distortion (%)	Total Voltage Distortion THD (%)
69 kV and below	3.0	5.0
69.001 kV Thru 161 kV	1.5	2.5
161 kV and above	1.0	1.5

Note:

High voltage systems can have up to 2.0% THD where the cause is an HVDC terminal that will attenuate by the time it is tapped for a user.

Two very important points must be made in reference to the above.

1. The customer is responsible for maintaining current distortion to within acceptable levels, while the utility is responsible for limiting voltage distortion.
2. The limits are only applicable at the point of common coupling (PCC) between the utility and the customer. The PCC, while not explicitly defined, is usually regarded as the point at which the utility equipment ownership meets the customer's or the metering point.

Therefore, the above limits cannot be meaningfully applied to distribution panels or individual equipment within a plant. The entire plant must be considered complying with these limits.

1.8. A Glossary of Basic Electrical Terms

V	Symbolizes volts or the electromotive force or electric pressure. Symbolizes the electric current flowing in the circuit in amperes.
I	Symbolizes the electric current flowing in the circuit in amperes.
P	Power in watts or kilowatts, indicates the real working component of the energy put in.
KVA	Indicates kilovolt amperes or the apparent power that determines the heating effect on the AC equipment and systems. All elements of the power systems must be sized to accommodate this burden.
KVAR	Kilovolt amperes reactive, or the 'Phantom Component' that vectorally combines with real power, to determine KVA on electric systems.
PF	Power factor or the ratio of real power (KW) to apparent power (KVA) percentage or as a decimal value.
Φ	Phase angle on the alternating current system, or the measure of the vector displacement between true power and apparent power, power factor expressed as the decimal value is the cosine of ϕ
kWh	Kilowatt-hours are the unit of electrical energy. kWh is obtained by integrating power, expressed in KW with time. For example, a power of 2KW appliance for 15 minutes (1/4 hour) indicates an energy consumption of $2 \times 1/4 = 0.5$ kWh.

Power	$\sqrt{3} \times V \times I \times PF$ for 3 phase systems, where V = Line voltage, I = line current • In delta connected electrical system, V line = V phase, I lines = $\sqrt{3}$ I phase • In star connected electrical system, V line = $\sqrt{3}$ V phase, I lines = I phase and $V \times I \times PF$ for single phase systems
KVA	$\sqrt{3} \times V \times I$ for 3 phase systems and $V \times I$ for single-phase systems.
Load factor	Load factor is the ratio of the average demand (KVA or KW) to the peak demand for a power system. High load factor leads to better utilization of installed capacity.
Demand Factor	Demand factor is the ratio of maximum demand to the connected load.
Peak Demand or Peak Load	The highest demand on an electric utility system is called peak load or Peak Demand. Demand varies with time every day and also from season to season. As electricity cannot be stored easily, utilities have to provide the generating capacity to meet peak demand even it lasts for a short duration.
Connected Load	Connected load is the summation of nameplate ratings (kW or kVA) of the electrical equipment installed in a consumer's premises
Load Management	Load management is a set of techniques for control of power supply and demand to increase the system load factor. Electric utilities as well as consumers can reduce the peak (maximum demand) by load shifting or load shedding (power cuts)

1.9. Analysis of Electrical Power Systems

System Problem	Common Causes	Possible Effects	Solutions
Voltage imbalances among the three phases	Improper transformer tap settings, single-phase loads not balanced among phases, poor connections, bad conductors, transformer grounds or faults.	Motor vibration, premature motor failure A 5% imbalance causes a 40% increase in motor losses.	Balance loads among phases.
Voltage deviations from rated voltages (too low or high)	Improper transformer settings, Incorrect selection of motors.	Over-voltages in motors reduce efficiency, power factor and equipment life Increased temperature	Correct transformer settings, motor ratings and motor input voltages
Poor connections in distribution or at connected loads.	Loose bus bar connections, loose cable connections, corroded connections, poor crimps, loose or worn contactors	Produces heat, causes failure at connection site, leads to voltage drops and voltage imbalances	Use Infra-Red camera to locate hot-spots and correct.

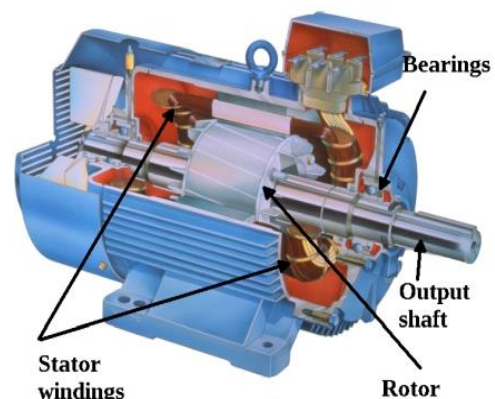
Undersized conductors.	Facilities expanding beyond original designs, poor power factors	Voltage drop and energy waste.	Reduce the load by conservation load scheduling.
Insulation leakage	Degradation over time due to extreme temperatures, abrasion, moisture, chemicals	May leak to ground or to another phase. Variable energy waste.	Replace conductors, insulators
Low Power Factor	Inductive loads such as motors, transformers, and lighting ballasts Non-linear loads, such as most electronic loads.	Reduces current-carrying capacity of wiring, voltage regulation effectiveness, and equipment life.	Add capacitors to counter act reactive loads.
Harmonics (non-sinusoidal voltage and/or current wave forms)	Office-electronics, UPSs, variable frequency drives, high intensity discharge lighting and electronic and core-coil ballasts.	Over-heating of neutral conductors, motors, transformers, switch gear. Voltage drop, low power	Take care with equipments election and isolate sensitive electronics from noisy circuits.

An analysis of an electrical power system may uncover energy waste, fire hazards, and equipment failure. Facility / Energy managers increasingly find that reliability-centered maintenance can save money, energy, and downtime.

ELECTRICAL MOTORS

1.10. INTRODUCTION

Electric motors convert electrical power into mechanical power by the interaction between the magnetic fields set up in the stator and rotor windings within a motor. In industrial applications, electric motor driven systems are used for various applications such as pumping, compressed air, fans, conveyors etc.



All industrial electric motors can be broadly classified as Induction Motors, Direct Current Motors or Synchronous Motors. All motor types have the same four operating components: Stator (stationary windings), Rotor (rotating windings), Bearings, and Frame (enclosure). All motors convert electrical energy in to mechanical energy by the interaction between the magnetic fields set up in the stator and rotor windings.

1.11. MOTOR TYPES

2.2.1 Induction Motors

Induction motors are the most commonly used in industrial applications. The induction motor is the most popular type of ac motor because of its simplicity and ease of operation. An induction motor does not have a separate field circuit; instead, it depends on transformer action to induce voltages and currents in its field circuit. In fact, an induction motor is basically a rotating transformer. Its equivalent circuit is similar to that of a transformer, except for the effects of varying speed. There are two types of induction motor rotors, cage rotors and wound rotors. Cage rotors consist of a series of parallel bars all around the rotor, shorted together at each end. Wound rotors are complete three-phase rotor windings, with the phases brought out of the rotor through slip rings and brushes. Wound rotors are more expensive and require more maintenance than cage rotors, so they are very rarely used (except sometimes for induction generators).

Figure 2.1: Non-Linear loads

In induction motors, the induced magnetic field of the stator winding induces a current in the rotor. In induction machines, rotor currents are induced in the rotor windings by a combination of the time-variation of the stator currents and the motion of the rotor relative to the stator. If a 3-phase supply is fed to the stator windings of a 3-phase motor, a magnetic flux of constant magnitude, rotating at synchronous speed is set up. At this point, the rotor is stationary. The rotating magnetic flux passes through the air gap between the stator & rotor and sweeps past the stationary rotor conductors. This rotating flux, as it sweeps, cuts the rotor conductors, thus causing an e.m.f to be induced in the rotor conductors. As per the Faraday's law of electromagnetic induction, it is this relative motion between the rotating magnetic flux and the stationary rotor conductors, which induces an e.m.f on the rotor conductors. Since the rotor conductors are shorted and form a closed circuit, the induced e.m.f produces a rotor current whose direction is given by Lenz's Law, is such as to oppose the cause producing it. In this case, the cause which produces the rotor current is the relative motion between the rotating magnetic flux and the stationary rotor conductors. Thus to reduce the relative speed, the rotor starts to rotate in the same direction as that of the rotating flux on the stator windings, trying to catch it up. The frequency of the induced e.m.f is same as the supply frequency. An induction motor normally operates at a speed near synchronous speed, but it can never operate at exactly n_{sync} .

Slip-ring motor

The slip-ring motor or wound-rotor motor is a variation of the squirrel cage induction motor. While the stator is the same as that of the squirrel cage motor, the rotor of a

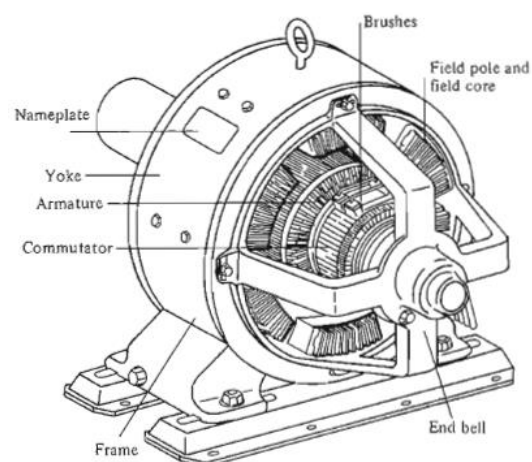
slip-ring motor is wound with wire coils. A slip ring induction motor is an asynchronous motor, as the rotor never runs in synchronous speed with the stator poles. The ends of the windings are connected to slip rings so that resistors or other circuitry can be inserted in series with the rotor coils through carbon brushes that slide on the slip-rings allowing an electrical connection with the rotating coils. This basically is the difference in construction between a squirrel cage and slip-ring motors. These are helpful in adding external resistors and contactors. The slip necessary to generate the maximum torque (pull-out torque) is directly proportional to the rotor resistance. In the slip-ring motor, the effective rotor resistance is increased by adding external resistance through the slip rings. Thus, it is possible to get higher slip and hence, the pull-out torque at a lower speed. A particularly high resistance can result in the pull-out torque occurring at almost zero speed, providing a very high pull-out torque at a low starting current. As the motor accelerates, the value of the resistance can be reduced, altering the motor characteristic to suit the load requirement. Once the motor reaches the base speed, external resistors are removed from the rotor. This means that now the motor is working as the standard induction motor.

This motor type is ideal for very high inertia loads, where it is required to generate the pull-out torque at almost zero speed and accelerate to full speed in the minimum time with minimum current draw.

Modifying the speed torque curve by altering the rotor resistors, the speed at which the motor will drive a particular load can be altered. At full load the speed can be reduced effectively to about 50% of the motor synchronous speed, particularly when driving variable torque/variable speed loads, such as printing presses, compressors, conveyer belts, hoists and elevators. Reducing the speed below 50%, results in very low efficiency due to higher power dissipation in the rotor resistances. This type of motor is used in applications for driving variable torque/ variable speed loads.

2.2.2 Direct-Current Motors

Direct-Current motors, as the name implies, use direct, i.e. unidirectional, current. Used in special applications, they only represent small percentage of motors used in industry, e.g. where high torque starting or where smooth acceleration over a broad speed range is required. Before the widespread use of power electronic rectifier-inverters, dc motors were unexcelled in speed control



applications.

The working of DC motor is based on the principle that when a current-carrying conductor is placed in a magnetic field, it experiences a mechanical force. The direction of mechanical force is given by Fleming's Left-hand Rule. There is no basic difference in the construction of a DC generator and a DC motor. In fact, the same D.C machine can be used interchangeably as a generator or as a motor.

There are five major types of dc motors in general use:

1. The separately excited dc motor
2. The shunt dc motor
3. The permanent-magnet dc motor
4. The series dc motor
5. The compounded dc motor

2.2.3 Synchronous Motors

In synchronous machines, rotor-winding currents are supplied directly from the stationary frame through a rotating contact. AC power is fed to the stator of the synchronous motor. The rotor is fed by dc from a separate source. The rotor magnetic field locks onto the stator rotating magnetic field and rotates at the same speed. The speed of the rotor is a function of the supply frequency and the number of magnetic poles in the stator. While induction motors with a slip, i.e., rpm is less than the synchronous speed, the synchronous motor rotate with no slip, i.e., the rpm is same as the synchronous speed governed by supply frequency and number of poles. The basic principle of synchronous motor operation is that the rotor "chases" the rotating stator magnetic field around in a circle, never quite catching up with it. The slip energy is provided for by the D.C. excitation power.

1.12. MOTOR CHARACTERISTICS

2.3.1 Motor Speed

The speed of a motor is the number of revolutions in a given time frame, typically revolutions per minute (RPM). The speed of an AC motor depends on the frequency of the input power and the number of poles for which the motor is wound. The synchronous speed in RPM is given by the following equation, where the frequency is in hertz or cycles per second:

$$\text{Synchronous Speed (RPM)} = \frac{120 * \text{Frequency}}{\text{No. of Poles}}$$

Motors have synchronous speeds like 3000 / 1500 / 1000 / 750 / 600 / 500 / 375 rpm

corresponding to no. of poles (always even) being 2, 4, 6, 8, 10, 12, 16 and given the mains frequency of 50 cycles / sec.

The actual speed with which the motor operates, will be less than the synchronous speed. The difference between synchronous and full load speed is called slip and is measured in percent. It is calculated using this equation:

$$\text{Slip (\%)} = \frac{\text{Synchronous Speed} - \text{Full Load Speed}}{\text{Synchronous Speed}} * 100$$

As per relation stated above, the speed of an AC motor is determined by the number of motor poles and by the input frequency. It can also be seen that theoretically speed of an AC motor can be varied infinitely by changing the frequency. For practical limits to speed variation, manufacturer's guidelines should be referred to. With the addition of a Variable Frequency Drive (VFD), the speed of the motor can be decreased as well as increased.

2.3.2 Volts/Hz Relationship

It has been seen that by changing the frequency, one can change the speed of the motor. However, frequency is not the only parameter that must be changed. Notice in the motor model below that the impedance of a motor will change with frequency since the impedance of an inductor equals to $2\pi fL$. At low frequencies, this impedance approaches zero making the circuit appear to be a short circuit.

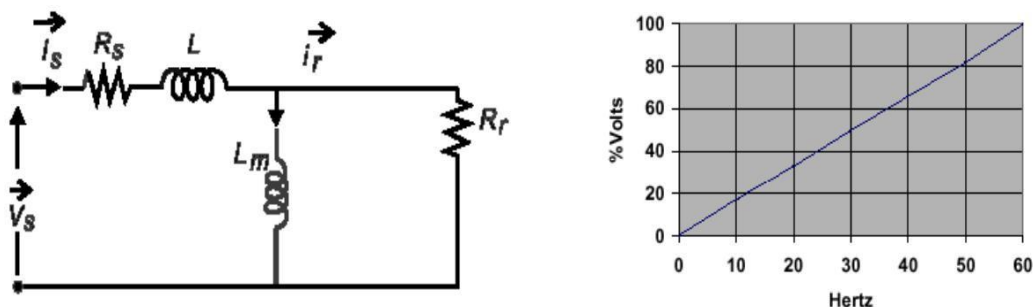


Figure 2.4: Volts/Hz Relationship

To maintain a constant flux in the motor, the voltage to the motor must also be changed. This ratio is constant over most of the entire speed range. By keeping the ratio constant, a fixed speed induction motor can be made to run at variable speed and provide constant torque as required by driven machine. At low speeds, due to the motor having inherent resistance in the windings, the ratio must be altered to provide enough magnetizing flux to spin the motor. The VFD allows this relationship to be altered by changing the voltage boost parameter.

2.3.3 Power Factor

The power factor of the motor is given as:

$$\text{Power Factor} = \cos \phi = \text{kW/kVA}$$

As the load on the motor comes down, the magnitude of the **active current** reduces. However, there is no corresponding reduction in the **magnetizing current**, with the result that the motor power factor reduces, with a reduction in applied load. Induction motors, especially those operating below their rated capacity, are the main reason for low power factor in electric systems.

Figure 2.5: Efficiency at different load

2.3.4 Motor Efficiency Parameters

Two important attributes relating to efficiency of electricity use by A.C. Induction motors are efficiency (η), defined as the ratio of the mechanical energy delivered at the rotating shaft to the electrical energy input at its terminals, and power factor (PF), defined as the ratio of the real power (kW) to apparent power (kVA) drawn by the motor. Motors, like other inductive loads, are characterized by power factors less than one. As a result, the total current draw needed to deliver the same real power is higher than for a load characterized by a higher PF. An important effect of operating with a PF less than one is that resistance losses in wiring upstream of the motor will be higher, since these are proportional to the square of the current. Thus, both a high value for η and a PF close to unity are desired for efficient overall operation in a plant.

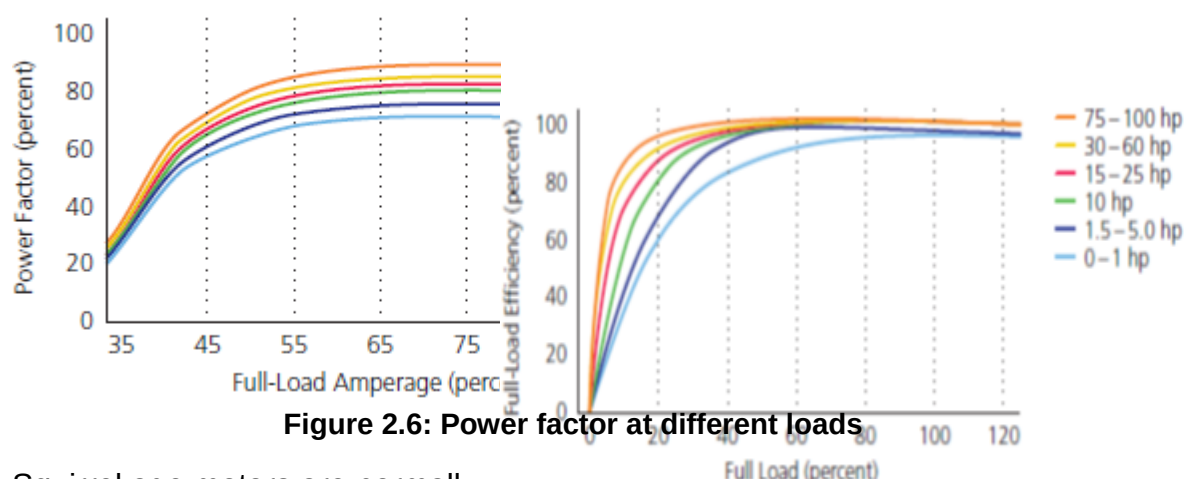


Figure 2.6: Power factor at different loads

Squirrel cage motors are normally more efficient than slip-ring motors, and higher-speed motors are normally more efficient than lower-speed motors. Efficiency is also a function of motor temperature. Totally-enclosed, fan-cooled (TEFC) motors are more efficient than screen-protected drip-proof (SPDP) motors. Also, as with most equipment, motor efficiency

increases with the rated capacity.

The efficiency of a motor is determined by intrinsic losses that can be reduced only by changes in motor design. Intrinsic losses are of two types—fixed, i.e., independent of motor load, and variable, i.e., dependent on load. Fixed losses consist of magnetic core losses and friction and windage losses. Magnetic core losses (sometimes called iron losses) consist of eddy current and hysteresis losses in the stator. They vary with the core material and geometry and within put voltage. Friction and windage losses are caused by friction in the bearing soft he motor and aero dynamic losses associated with the ventilation fan and other rotating parts. Variable losses consist of resistance losses in the stat or and in the rotor and miscellaneous stray losses. Resistance to current flow in the stator and rotor result in heat generation that is proportional to the resistance of the material and the square of the current (I^2R). Stray losses arise from a variety of sources and are difficult to either measure directly or to calculate, but are generally proportional to the square of the rotor current.

Part-load performance characteristics of a motor also depend on its design. For operating loads in the range of 50 – 100 percent of rated load, the reductions in η decreases significantly, and PF continues to fall. Both η and PF fall to very low levels at low loads.

1.13. MOTORS SELECTION

The primary technical consideration defining the motor choice for any particular application is the torque required by the load. Especially important is the relationship between the maximum torque generated by the motor (break-down torque) and the torque requirements for start-up (locked rotor torque) and during acceleration periods. Other load characteristics, e.g., constant versus variable torque requirements or constant versus variable speed also are considered in the selection process.

The duty/ load cycle determines the thermal loading on the motor. One consideration with totally enclosed fan cooled (TEFC) motors is that the cooling may be insufficient when the motor is operated at speeds blow its rated value.

Several additional selection criteria are also typically considered. Ambient operating conditions affect motor choice: special motor designs are available for corrosive or dusty atmospheres, high temperatures, restricted physical space etc.

Anticipated switching frequency is an important consideration: an estimate of the frequency of switching (usually dictated by the process), whether automatic or manually controlled, can help in selecting the appropriate motor for the duty cycle.

The demand a motor will place on the balance of the plant electrical system is another consideration: if the load variations are large, for example as are sult of frequent starts and stops of large components like compressors, the resulting large voltage drops could be detrimental to other equipment.

There are still other considerations that can influence the motor selection. Reliability is of prime importance. In many cases, however, designers and process engineers seeking reliability will grossly over size equipment, leading to sub-optimal energy performance. Good knowledge of process parameters and a better understanding of the plant power system can aid in reducing over sizing with no loss of reliability. Inventory is another consideration.

Many large industries use standard equipment, which can be easily serviced or replaced, thereby reducing the stock of spare parts that must be maintained and minimizing shut-downtime. This practice affects the choice of motors that might provide better energy performance in specific applications. Shorter lead times for securing individual motors from suppliers would help reduce the need for this practice. Price is another issue. Many users are first-cost sensitive, leading to the purchase of less expensive motors that may be more costly on a lifecycle basis because of lower efficiency. For example, energy efficient motors or other specially designed motors typically save within a few years an amount of money equal to several times the incremental cost for an energy efficient motor, over a standard-efficiency motor.

2.4.1 Field Tests for Determining Efficiency

No Load Test:

The motor is run at rated voltage and frequency without any shaft load. Input power, current frequency and voltage are noted. The no load P.F. is quite low and hence low PF wattmeter is required. From the input power, stator I^2R losses under no load are subtracted to give the sum of friction, wind age and core losses. To separate core and F&W losses, testis repeated at variable voltages. It is worthwhile plotting no-load input kW versus Voltage; the intercept is F& W kW loss component.

Stator and Rotor I^2R Losses:

The stator winding resistance is directly measured by a bridge or volt amp method.

The resistance must be corrected to the operating temperature. For modern motors, the operating temperature is likely to be in the range of 100°C to 120°C and necessary correction should be made. Correction to 75°C may be inaccurate. The correction factor is given as follows:

$$\frac{R_2}{R_1} = \frac{235 - t_2}{235 + t_1}$$

The rotor resistance can be determined from locked rotor test at reduced frequency, but rotor I^2R losses are measured from measurement of rotor slip.

Rotor I^2R losses = Slip × (Stator Input – Stator I^2R Losses – Core Loss)

Accurate measurement of slip is possible by stroboscope or non-contact type tachometer. Slip also must be corrected to operating temperature.

Stray Load Losses:

These losses are difficult to measure with any accuracy. IEEE Standard 112 gives a complicated method, which is rarely used on shop floor. IS and IEC standards take a fixed value as 0.5 % of output. It must be remarked that actual value of stray losses is likely to be more. IEEE – 112 specifies values from 0.9 % to 1.8%.

Motor Rating	Stray Losses
1 – 125HP	1.8 %
125 – 500HP	1.5 %
501 – 2499HP	1.2 %
2500 and above	0.9 %

Points for Users:

It must be clear that accurate determination of efficiency is very difficult. The same motor tested by different methods and by same methods by different manufacturers can give a difference of 2%. In view of this, for selecting high efficiency motors, the following can be done:

- When purchasing large number of small motors or a large motor, ask for a detailed test certificate. If possible, try to remain present during the tests.
- See that efficiency values are specified without any tolerance
- Check the actual input current and kW, if replacement is done
- For new motors, keep a record of no load input current and power
- Use values of efficiency for comparison and for confirming; rely on measured inputs for all calculations.

Estimation of efficiency in the field can be done as follows:

- Measure stator resistance and correct to operating temperature. From rated current value, I^2R losses are calculated.

- From rated speed and output, rotor I^2R losses are calculated
- From no load test, core and F & W losses are determined.

The method is illustrated by the following example:

Example:

Motor Specifications

Rated power	=	34 kW/45 HP
Voltage	=	415 Volt
Current	=	57 Amps
Speed	=	1475 rpm
Insulation class	=	F
Frame	=	LD 200L
Connection	=	Delta

No load test Data

Voltage, V	=	415 Volts
Current, I	=	16.1 Amps
Frequency, F	=	50Hz
Stator phase resistance at 30°C	=	0.264 Ohms
No load power, P_{nl}	=	1063.74 Watts

- Calculate iron plus friction and windage losses
- Calculate stator resistance at 120°C
$$R_2 = R_1 * \frac{235 + t_2}{235t_1}$$
- Calculate stator copper losses at operating temperature of resistance at 120°C
- Calculate full load slip (s) and rotor input assuming rotor losses are slip times rotor input.
- Determine the motor input assuming that stray losses are 0.5% of the motor rated power
- Calculate motor full load efficiency and full load power factor

Solution

- Iron plus friction and windage loss, $P_i = f_w P_{nl} = 1063.74$ Watts
Stator Copper loss, $P_{st-30^\circ C} = 3 \times (16.2/\sqrt{3})^2 \times 0.264 = 68.43$ Watts

$$P_i + f_w = P_{in} - P_{st} - P_{cu} = 1063.74 - 68.43 = 995.3$$

b) Stator Resistance at 120°C,

$$R_{120^\circ C} = 0.264 \times (120 + 235 / 30 + 235) = 0.354 \text{ ohms}$$

c) Stator copper losses at full load,

$$P_{st} - P_{cu-120^\circ C} = 3 \times (57 / \sqrt{3})^2 \times 0.354 = 1150.1 \text{ Watts}$$

d) Full load slip

$$S = (1500 - 1475) / 1500 = 0.0167$$

$$\text{Rotor input, } P_r = P_{\text{output}} (1 - S) = 34000 / (1 - 0.0167) = 34577.4 \text{ Watts}$$

e) Motor full load input power, P_{input}

$$= P_r + P_{st} - P_{cu-120^\circ C} + P_i + f_w + P_{\text{stray}} = 34577.4 + 1150.1 + 995.3 + (0.005 \times 34000) = 36892.8 \text{ Watts}$$

f) Motor efficiency at full load Efficiency

$$= P_{\text{out}} / P_{\text{input}} \times 100 = 34000 / 36892.8 \times 100 = 92.2\%$$

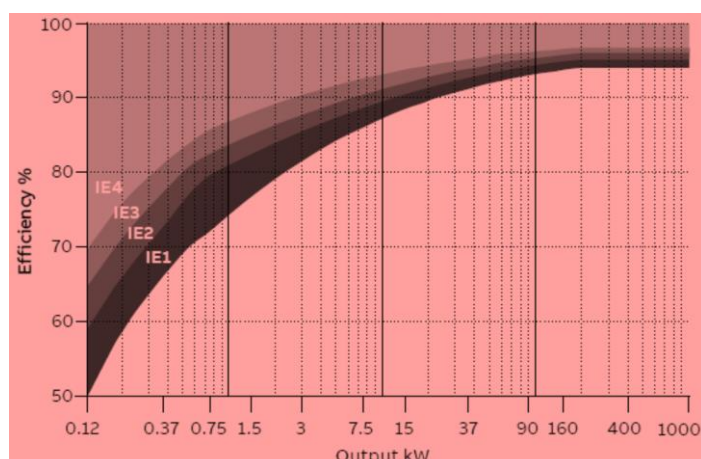
$$\text{Full Load PF} = P_{\text{input}} / \sqrt{3} \times V \times I = 36892.8 / 3 \times 415 \times 7 = 0.9$$

Comments:

- The measurement of stray load losses is very difficult and not practical even on test beds.
- The actual value of stray loss of motors up to 200HP is likely to be 1% to 3% compared to 0.5 % assumed by standards.
- The value of full load slip taken from the name plate data is not accurate. Actual measurement under full load conditions will give better results.
- The friction and windage losses really are part of the shaft output; however, in the above calculation, it is not added to the rated shaft output, before calculating the rotor input power. The error however is minor.
- When a motor is rewound, there is a fair chance that the resistance per phase would increase due to winding material quality and the losses would be higher. It would be interesting to assess the effect of a nominal 10 % increase in resistance per phase.

1.14. ENERGY-EFFICIENT MOTORS

Energy-efficient motors are the ones in which, design improvements are incorporated specifically to increase operating efficiency over motors of standard design. Design improvements focus on reducing intrinsic motor losses. Improvements include the use of lower-loss steel a longer core (to increase active material), thicker



wires (to reduce resistance), thinner laminations,

smaller air gap between stator and rotor, copper instead of aluminum bars in the rotor, superior bearings and a smaller fan, etc. energy-efficient motors now available operate with efficiencies that are typically 3 to 4 percentage points higher than standard motors. As per the standard IEC 60034-30-1, energy-efficient motors are designed to operate without loss in efficiency at loads between 75 % and 100 % of rated capacity. This may result in major benefits in varying load applications. The power factor is about the same or may be higher than for standard motors. Furthermore, energy- efficient motors have lower operating temperatures and noise levels, greater ability to accelerate higher-inertia loads, and are less affected by supply voltage fluctuations.

Measures adopted for energy efficiency address each loss specifically as under:

2.5.1 Stator and Rotor I^2R Losses

These losses are major losses and typically account for 55% to 60% of the total losses. I^2R losses are heating losses resulting from current passing through stator and rotor conductors. I^2R losses are the function of a conductor resistance, the square of current. Resistance of conductor is a function of conductor material, length and cross sectional area. The suitable selection of copper conductor size will reduce the resistance. Reducing the motor current is most readily accomplished by decreasing the magnetizing component of current. This involves lowering the operating flux density and possible shortening of air gap. Rotor I^2R losses are a function of the rotor conductors (usually Aluminium) and the rotor slip. Utilisation of copper conductors will reduce the winding resistance. Motor operation closer to synchronous speed will also reduce rotor I^2R losses.

2.5.2 Core Losses

Core losses are those found in the stator-rotor magnetic steel and are due to hysteresis effect and eddy current effect during 50 Hz magnetization of the core material. These losses are independent of load and account for 20 – 25 % of the total losses.

The hysteresis losses which are a function of flux density, are reduced by utilizing low-loss grade of silicon steel laminations. The reduction of flux density is achieved by suitable increase in the core length of stator and rotor. Eddy current losses are generated by circulating current within the core steel laminations. These are reduced by using thinner laminations.

2.5.3 Friction and Windage Losses

Friction and Wind age losses results from be a ring friction, wind age and circulating air through the motor and account for 8–12%oftotallosses. These losses are independent of load. The reduction in heat generated by stator and rotor losses permits the use of smaller fan. The wind age losses also reduce with the diameter of fan leading to reduction in wind age losses.

2.5.4 Stray Load-Losses

These losses vary according to square of the load current and are caused by leakage flux induced by load currents in the laminations and account for 4 to 5% of total losses. These losses are reduced by careful selection of slot numbers, tooth/slot geometry and air gap.

As a result of the modifications to improve performance, the costs of energy-efficient motors are higher than those of standard motors. The higher cost will often be paid back rapidly in saved operating costs, particularly in new applications or end-of-life motor replacements. In cases where existing motors have not reached the end of their useful life, the economics will be less clearly positive.

Energy efficient motors cover a wide range of ratings and the full load efficiencies are higher by 3 to 7 %. The mounting dimensions are also maintained as per BDS 1196:1988 to enable easy replacement.

Because the favourable economics of energy -efficient motors are based on savings in operating costs, there may be certain cases which are generally economically ill-suited to energy-efficient motors. These include highly intermittent duty or special torque applications such as hoists and cranes, traction drives, punch presses, machine tools, and centrifuges. In addition, energy efficient designs of multi-speed motors are generally not available. Furthermore, most energy-efficient motors produced today are designed only for continuous duty cycle operation.

Given the tendency of over sizing on the one hand and ground realities like; voltage, frequency variations, efficacy of rewinding in case of a burnout, on the other hand, benefits of EEM's can be achieved only by careful selection, implementation, operation and maintenance efforts of energy managers.

Energy Efficient Motors	
Power Loss Area	Efficiency Improvement
1. Iron	Use of thinner gauge, lower loss core steel reduces eddy current losses. Longer core adds more steel to the design, which reduces losses due to lower operating flux densities.
2. Stator $I^2 R$	Use of more copper and larger conductors increases cross sectional area

	of stator windings. This lowers resistance (R) of the windings and reduces losses due to current flow (I).
3. Rotor $I^2 R$	Use of larger rotor conductor bars increases size of cross section, lowering conductor resistance (R) and losses due to current flow (I).
4. Friction & Windage	Use of low loss fan design reduces losses due to air movement.
5. Stray Load Loss	Use of optimized design and strict quality control procedures minimizes stray load losses.

1.15. FACTORS AFFECTING ENERGY EFFICIENCY & MINIMISING MOTOR LOSSES IN OPERATION

2.6.1 Power Supply Quality

Motor performance is affected considerably by the quality of input power that is the actual volts and frequency available at motor terminals vis-à-vis rated values as well as voltage and frequency variations and voltage unbalance across the three phases. Motors in Bangladesh must comply with standards set by the BANGLADESH STANDARDS AND TESTING INSTITUTION (BSTI) for tolerance to variations in input power quality. The BSTI standards specify that a motor should be capable of delivering its rated output with a voltage variation and frequency variation. Voltage fluctuations can have detrimental impacts on motor performance. The general effects of voltage and frequency variation on motor performance are presented in following figure 2.8:

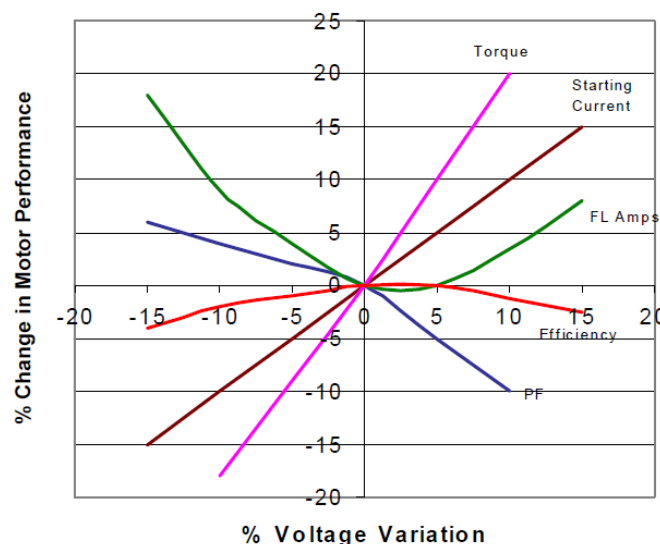


Figure 2.8: Effect of Voltage Variation on Induction Motors

Effect of Frequency Variation

Motors built in accordance to NEMA standards are designed to operate successfully at rated load and at rated voltage with a variation in the frequency of up to 5% above or below the rated frequency. The information in the following table is based on voltage being held constant.

Freq.	Starting and Max. Torque	Synchronous Speed	% Slip	Full Load Speed	Full Load Eff	Full Load PF	Full Load Current	Locked Rotor Current	Temp. Rise @ Full Load	Max. Overload Capacity	Magnetic Noise (No load)
105%	Decrease 10%	Increase 11%	Practically No Change	Increase 5%	Slight Increase	Slight Increase	Decrease Slightly	Decrease 5-6%	Decrease Slightly	Decrease Slightly	Decrease Slightly
95%	Increase 11%	Decrease 10%	Practically No Change	Decrease 5%	Slight Decrease	Slight Decrease	Increase Slightly	Increase 5-6%	Increase Slightly	Increase Slightly	Increase Slightly

Effect of Voltage Variation

Induction motors are normally designed to give satisfactory performance on a line voltage of up to 10% above or 10% below the rated value per NEMA standards

Voltage	Starting and Max. Torque	Synchronous Speed	% Slip	Full Load Speed	Full Load Eff	Full Load PF	Full Load Current	Locked Rotor Current	Temp. Rise @ Full Load	Max. Overload Capacity	Magnetic Noise (No load)
110%	Increase 21%	No change	Decrease 17%	Increase 1%	Increase 0-1 point	Decrease 2-8 points	Decrease 0-7%	Increase 10-14%	Decrease 4-6OC	Increase 21%	Increase slightly
90%	Decrease 21%	No change	Increase 23%	Decrease 1%	Decrease 1-3 points	Increase 1-3 points	Increase 10-12%	Decrease 10-12%	Increase 4-8OC	Decrease 19%	Decrease slightly

The options available for an energy manager to ensure near to rated voltage at motor terminals include:

- Load end power factor improvement by providing matching PF capacitors.
- Minimizing line / cable voltage drops from sub-station to motor terminals.
- Transformers tap changing as required in case of consistent and continuous low voltage situations.

Voltage unbalance, the condition where the voltages in the three phases are not equal, can be still more detrimental to motor performance and motor life. Unbalance typically occurs as a result of supplying single-phase loads disproportionately from one of the phases. It can also result from the use of different sizes of cables in the distribution system.

Table 2.1: Example of the Effect of Voltage Unbalance on Motor Performance

Unbalance in current (%)	Percent unbalance in voltage*		
	0.30 0.4	2.30 17.7	5.40 40.0
Increased temperature rise(⁰ C)	0	30	40

Percent unbalance in voltage is defined as $100 (V_{\max} - V_{\text{avg}}) / V_{\text{avg}}$, Where $V_{\max}$ and V_{avg} are the largest and the average of the three phase voltages, respectively.

The NEMA (National Electrical Manufacturers Association of USA) standard definition of voltage unbalance is given by the following equation:

$$\text{Voltage unbalance} = \frac{\text{Maximum deviation from mean of } V_{ab}, V_{bc}, V_{ca}}{\text{Mean of } (V_{ab}, V_{bc}, V_{ca})}$$

For example, if the line voltages are $V_{ab} = 410$, $V_{bc} = 417$, and $V_{ca} = 408$

$$\% \text{ Voltage unbalance} = (417 - 411.7 / 411.667) \times 100 = 1.29 \%$$

Where,

$$\text{Mean} = (410 + 417 + 408) / 3 = 411.7$$

Hence the voltage unbalance is 1.29%.

Common Causes of Voltage Unbalance

It is recommended that the voltage unbalance at the motor terminals not exceed 1%, anything above this will lead to de rating of the motor. The common causes of voltage unbalance are

Some of the more common causes of unbalanced voltages are:

- ✚ Unbalanced incoming utility supply
- ✚ Unequal transformer tap settings
- ✚ Large single phase distribution transformer on the system
- ✚ Open phase on the primary of a 3 phase transformer on the distribution system
- ✚ Faults or grounds in the power transformer
- ✚ Open delta connected transformer banks
- ✚ A blown fuse on a 3 phase bank of power factor improvement capacitors
- ✚ Unequal impedance in conductors of power supply wiring
- ✚ Unbalanced distribution of single phase loads such as lighting
- ✚ Heavy reactive single phase loads such as welders

Voltage unbalance is probably the leading power factor problem that results in motor overheating and premature motor failure.

Voltage unbalance causes extremely high current imbalance. The magnitude of current imbalance may be 6 to 10 times as large as the voltage imbalance. A motor will run hotter when operating on a power supply with voltage unbalance. The additional temperature rise is estimated with the following equation

$$\text{Additional temperature rise} = 2 \times (\% \text{ Voltage unbalance})^2$$

For example, if the voltage unbalance is 2% for a motor operating at 100 °C, the additional temperature rise will be 80°C. The winding insulation life is reduced by one half for each 10 °C increase in operating temperature.

The options that an Energy Manager can exercise to minimize voltage unbalance include:

- Balancing any single phase loads equally among all the three phases
- Segregating any single phase loads which disturb the load balance and feed them from a separate line / transformer.

2.6.2 Motor Loading

2.6.2.1 Measuring Load

Knowing the load on the motor over its typical operating cycle is critical to understanding the potential for improving motor use efficiency. Under-loading and variable loading can produce inefficient motor operation. However, it is normally quite difficult to ascertain the load on the motor, as it requires measuring input power, current, voltage, frequency and motor speed under both load and no-load conditions. Measurement of the stat or resistance is also required. It is generally

inadequate to measure only the current drawn under load, as this can give misleading results. The no-load measurements provide the basis for estimating fixed losses, which, together with the measurements under load, permit motor efficiency to be estimated (IEEE,1984). Proper instrumentation is critical to making accurate measurements.

2.6.2.2 Reducing Under-loading

Probably the most pervasive practice contributing to sub-optimal motor efficiency is that of under-loading. Under-loading results in lower efficiency and power factor, and higher than necessary first cost for the motor and related control equipment. Under-loading is common for several reasons. Original equipment manufacturers tend to use a large safety factor in motors they select. Under-loading of the motor may also occur from under-utilization of the equipment. For example, machine tool equipment manufacturers provide for a motor rated for the full capacity load of the equipment ex. depth of cut in a machine. The user may need this full capacity rarely, resulting in under-loaded operation most of the time. Another common reason for under-loading is selection of a larger motor to enable the output to be maintained at the desired level even when input voltages are abnormally low. Finally, under-loading also results from selecting a large motor for an application requiring high starting torque where a special motor, designed for high torque, would have been suitable.

A careful evaluation of the load would determine the capacity of the motor that should be selected. Another aspect to consider is the incremental gain in efficiency achievable by changing the motor. Larger motors have inherently higher rated efficiencies than smaller motors. Therefore, the placement of motors operating at 60–70% of capacity or higher is generally not recommended. However, there are no rigid rules governing motor selection; the savings potential needs to be evaluated on a case-to-case basis. When downsizing, it may be preferable to select an energy-efficient motor, the efficiency of which may be higher than that of a standard motor of higher capacity.

For motors which consistently operate at loads below 50% of rated capacity, an inexpensive and effective measure might be to operate in star mode. A change from the standard delta operation to star operation involves re-configuring the wiring of the three phases of power input at the terminal box.

Operating in the star mode leads to a voltage reduction by a factor of ' $\sqrt{3}$ '. Motor output falls to one-third of the value in the delta mode, but performance characteristics as a function of load remain unchanged. Thus, full-load operation in star mode gives higher efficiency and power factor than partial load operation in the

delta mode. However, motor operation in the star mode is possible only for applications where the torque-to-speed requirement is lower at reduced load.

For applications with high initial torque and low running torque needs, Delta-Star starters are also available in market, which help in load following de-rating of electric motors after initial start-up.

2.6.2.3 Sizing to Variable Load

Industrial motors frequently operate under varying load conditions due to process requirements. A common practice in cases where such variable-loads are found is to select a motor based on the highest anticipated load. In many instances, an alternative approach is typically less costly, more efficient, and provides equally satisfactory operation. With this approach, the optimum rating for the motor is selected on the basis of the load duration curve for the particular application. Thus, rather than selecting a motor of high rating that would operate at full capacity for only a short period, a motor would be selected with a rating slightly lower than the peak anticipated load and would operate at overload for a short period of time. Since operating within the thermal capacity of the motor insulation is of greatest concern in a motor operating at higher than its rated load, the motor rating is selected as that which would result in the same temperature rise under continuous full-load operation as the weighted average temperature rise over the actual operating cycle. Under extreme load changes, e.g. frequent starts / stops, or high inertial loads, this method of calculating the motor rating is unsuitable since it would underestimate the heating that would occur.

Where loads vary substantially with time, in addition to proper motorizing, the control strategy employed can have a significant impact on motor electricity use. Traditionally, mechanical means (e.g. throttle valves in piping systems) have been used when lower output is required. More efficient speed control mechanisms include multi-speed motors, eddy-current couplings, fluid couplings, and solid-state electronic variable speed drives.

2.6.3 Power Factor Correction

As noted earlier, induction motors are characterized by power factors less than unity, leading to lower overall efficiency (and higher overall operating cost) associated with a plant's electrical system. Capacitors connected in parallel (shunted) with the motor are typically used to improve the power factor. The impacts of PF correction include reduced kVA demand (and hence reduced utility demand charges), reduced I^2R losses in cables up stream of the capacitor (and hence

reduced energy charges), reduced voltage drop in the cables (leading to improved voltage regulation), and an increase in the overall efficiency of the plant electrical system.

The size of capacitor required for a particular motor depends upon the no-load reactive kVA (kVAR) drawn by the motor, which can be determined only from no-load testing of the motor. In general, the capacitor is then selected to not exceed 90% of the no-load kVAR of the motor. (Higher capacities could result in over-voltages and motor burn-outs). Alternatively, typical power factors of standard motors can provide the basis for conservative estimates of capacitor ratings to use for different size motors.

Table 2.2: Capacitor ratings for power factor correction by direct connection to induction motors

Motor Rating(HP)	Capacitor rating (kVAR) for Motor Speed					
	3000	1500	1000	750	600	500
5	2	2	2	3	3	3
7.5	2	2	3	3	4	4
10	3	3	4	5	5	6
15	3	4	5	7	7	7
20	5	6	7	8	9	10
25	6	7	8	9	9	12
30	7	8	9	10	10	15
40	9	10	12	15	16	20
50	10	12	15	18	20	22
60	12	14	15	20	22	25
75	15	16	20	22	25	30
100	20	22	25	26	32	35
125	25	26	30	32	35	40
150	30	32	35	40	45	50
200	40	45	45	50	55	60
250	45	50	50	60	65	70

Since a reduction in line current, and associated energy efficiency gains, are reflected backwards from the point of application of the capacitor, the maximum improvement in overall system efficiency is achieved when the capacitor is connected across the motor terminals, as compared to somewhere further upstream in the plant's electrical system. However, economies of scale associated with the cost of capacitors and the labor required to install them will place an economic limit on the lowest desirable capacitor size.

Energy managers can, by a motor load survey, arrive at capacitor ratings, locations and cost benefits. One factor to be considered “operating hours” of motor.

2.6.4 Maintenance

Inadequate maintenance of motors can significantly increase losses and lead to unreliable operation. For example, improper lubrication can cause increased friction in both the motor and associated drive transmission equipment. Resistance losses in the motor, which rise with temperature, would increase. Providing adequate ventilation and keeping motor cooling ducts clean can help dissipate heat to reduce excessive losses. The life of the insulation in the motor would also be longer: for every 10⁰C increase in motor operating temperature over the recommended peak, the time before rewinding would be needed is estimated to be halved.

A check list of good maintenance practices to help insure proper motor operation would include:

- Inspecting motors regularly for wear in bearings and housings (to reduce frictional losses) and for dirt/dust in motor ventilating ducts (to ensure proper heat dissipation).
- Checking load conditions to ensure that the motor is not over or under loaded. A change in motor load from the last test indicates a change in the driven load, the cause of which should be understood.
- Lubricating appropriately. Manufacturers generally give recommendations for how and when to lubricate their motors. Inadequate lubrication can cause problems, as noted above. Over-lubrication can also create problems, e.g. excess oil or grease from the motor bearings can enter the motor and saturate the motor insulation, causing premature failure or creating a fire risk.
- Checking periodically for proper alignment of the motor and the driven equipment. Improper alignment can cause shafts and bearings to wear quickly, resulting in damage to both the motor and the driven equipment.
- Ensuring that supply wiring and terminal box are properly sized and installed. Inspect regularly the connections at the motor and starter to be sure that they are clean and tight.

2.6.5 Age

Most motor cores are manufactured from silicon steel or de-carbonized cold-rolled steel, the electrical properties of which do not change measurably with age.

However, poor maintenance (inadequate lubrication of bearings, insufficient cleaning of air cooling passages, etc.) can cause a deterioration in motor efficiency overtime. Ambient conditions can also have a detrimental effect on motor performance. For example, excessively high temperatures, high dust loading, corrosive atmosphere, and humidity can impair insulation properties; mechanical stresses due to load cycling can lead to mis-alignment. However, with adequate care, motor performance can be maintained.

2.6.6 Rewinding Effects on Energy Efficiency

It is common practice in industry to rewind burnt-out motors. The population of rewound motors in some industries exceeds 50% of the total population. Careful rewinding can sometimes maintain motor efficiency at previous levels, but in most cases, losses in efficiency result. Rewinding can affect a number of factors that contribute to determining motor efficiency: winding and slot design, winding material, insulation performance, and operating temperature. For example, a common problem occurs when heat is applied to strip old windings: the insulation between laminations can be damaged, thereby increasing eddy current losses. A change in the air gap may affect power factor and output torque.

However, if proper measures are taken, motor efficiency can be maintained, and in some cases increased, after rewinding. Efficiency can be improved by changing the winding design, though the power factor could be affected in the process. Using wires of greater cross section, slot size permitting, would reduce stat or losses thereby increasing efficiency. However, it is generally recommended that the original design of the motor be preserved during the rewind, unless there are specific, load-related reasons for redesign.

The Impact of rewinding on motor efficiency and power factor can be easily assessed if the no-load losses of a motor are known before and after rewinding. Maintaining documentation of no-load losses and no-load speed from the time of purchase of each motor can facilitate assessing this impact.

Monitoring Format for Rewound Motors

Section	Equipment Code	Motor Code	Motor Type		No Load Current				Starter Resistance/phase		No load loss	
			Sq.Cage	Slip Ring	New Motor		After Rewinding		New	Rewound	New	Rewound
					A	V	A	V			Watts	Watts

2.6.7 Speed Control of AC Induction Motors

Traditionally, DC motors have been employed when variable speed capability was desired. By controlling the armature (rotor) voltage and field current of a separately-excited DC motor, a wide range of output speeds can be obtained. DC motors are available in a wide range of sizes, but their use is generally restricted to a few low speed, low-to-medium power applications like machine tools and rolling mills because of problems with mechanical commutation at large sizes. Also, they are restricted for use only in clean, non-hazardous areas because of the risk of sparking at the brushes. DC motors are also expensive relative to AC motors.

Because of the limitations of DC systems, AC motors are increasingly the focus for variable speed applications. Both AC synchronous and induction motors are suitable for variable speed control. Induction motors are generally more popular, because of their ruggedness and lower maintenance requirements. AC induction motors are inexpensive (half or less of the cost of a DC motor) and also provide a high power to weight ratio (about twice that of a DC motor).

An induction motor is an asynchronous motor, the speed of which can be varied by changing the supply frequency. The speed can also be varied through anumber of other means, including varying the input voltage, varying the resistance of the rotor circuit, using multi-speed windings, using mechanical means such as gears and pulleys or static voltage and frequency converters. The control strategy to be adopted in any particular case will depend on a number of factors including investment cost, load reliability and any special control requirements. Thus, for any particular application, a detailed review of the load characteristics, historical data on process flows, the features required of the speed control system, the electricity tariffs and the investment costs would be a prerequisite to the selection of a speed control system.

The characteristics of the load are particularly important. Load refers essentially to the torque output and corresponding speed required. Loads can be broadly classified as constant torque, variable torque and constant power. Constant torque loads are those for which the output power requirement may vary with the speed of operation but the torque does not vary. Conveyors, rotary kilns, and constant-displacement pumps are typical examples of constant torque loads. Variable torque loads are those for which the torque required varies with the speed of operation. Centrifugal pump and fans are typical examples of variable torque loads (torque varies as the square of the speed). Constant power loads are those for which the torque requirements typically change inversely with speed. Machine tools are

atypical example of a constant power load.

The largest potential for electricity savings with variable speed drives is generally in variable torque applications, for example centrifugal pumps and fans, where the power requirement changes as the cube of speed. Constant torque loads are also suitable for VSD application.

Quantifying the magnitude and temporal variation of the load in any specific case is difficult without adequate instrumentation and an effective monitoring system. For example, for pumping application, measured data on variations in flow, pressure, temperature, head, voltage, current and power would be required along with matched data on production, product mix or grade (if applicable), power supply interruptions, changes due to seasonal variations (if applicable), planned or unplanned shut downs, and effect of start-up on process energy requirements. Extensive data of this form typically are not available. However, in many applications, equipment is over sized due to the safety margins applied at each stage of the system design, in which cases a simpler analysis based on fewer or not significant savings are possible.

2.6.7.1 Electro-Mechanical Speed Control Systems

Electro-mechanical speed control mechanisms include purely mechanical systems, multi-speed motors, eddy-current drives, and fluid couplings. The characteristics of these are summarized in the table below.

i. Gears, pulleys, etc.

A variety of purely mechanical systems are available for motor speed control, including variable pulley sheaves, gears, chains, and friction drives. These systems provide limited speed variation and do not lend themselves to automatic control, but are suitable for applications which require operation at a few fixed speeds and adjustment at infrequent intervals.

ii. Multi-speed motors

Motors can be wound such that two speeds, in the ratio of 2:1, can be obtained. Motors can also be wound with two separate windings, each giving 2 operating speeds, for a total of four speeds. Multi-speed motors can be designed for applications involving constant torque, variable torque, or for constant output power. Multi-speed motors are suitable for applications which require limited speed control (two or three fixed speeds instead of continuously variable speed), in which cases they tend to be very economical.

Table 2.3: Electro Mechanical Speed Control alternatives for AC Induction Motors

VSD Type (Power, Speed Range)	Advantages	Disadvantages
ELECTRO-MECHANICAL CONTROL METHODS		
Gears, Pulleys, etc.		
Variable Pulley Sheaves	Low Cost	Low power savings; high maintenance costs
Gears	Low Cost	Low power savings; high maintenance costs
Chains	Low Cost	Low power savings; high maintenance costs
Friction Drives	Low Cost	Low power savings; high maintenance costs
Multispeed Motors	Operational at 2 or 4 Fixed Speeds	Stepped speed control; lower efficiency than single-speed motors
Eddy-current Drives >0kW, 10:1	Simple; relatively low cost; step less speed control	Needs low efficiency at below 50% rated speed
Fluid Coupling Drives >0 kW, 5: 1	Simple; relatively low cost; stepless speed control	Low efficiency at below 50% rated speed

iii. Eddy-current drives

This method employs a needy-current clutch to vary the output speed. The clutch consists of a primary member coupled to the shaft of the motor and a freely revolving secondary member coupled to the load shaft. The secondary member is separately excited using a DC field winding. The motor starts with the load at rest and a DC excitation is provided to the secondary member which induces eddy-currents in the primary member. The interaction of the fluxes produced by the two currents gives rise to a torque at the load shaft. By varying the DC excitation the output speed can be varied to match the load requirements. The major disadvantage of this system is relatively poor efficiency, particularly at low speeds.

iv. Fluid-coupling drives

Power can be transmitted through a fluid either by hydro-static, hydro-kinetic, hydro-viscous, or hydro-dynamic forces. In most commercial fluid coupling drives, normally a light mineral oil, which in turn transmits the energy to the load.

Construction

Fluid couplings work on the hydrodynamic principle. It consists of a pump-generally known

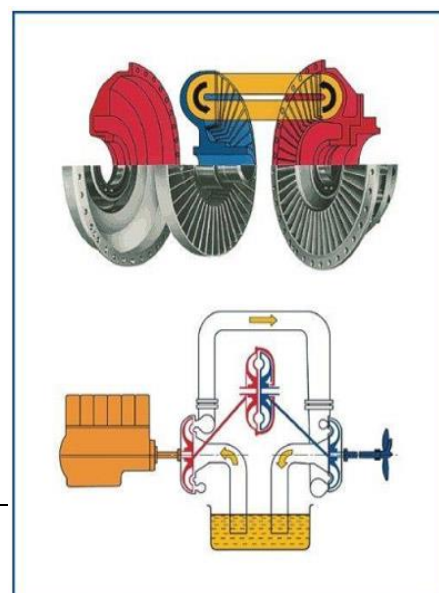


Figure 2.9: Fluid Coupling

as impeller and a turbine generally known as rotor, both enclosed suitably in a casing. The impeller and the rotor are bowl-shaped and have large number of radial vanes. They face each other with an air gap. The impeller is suitably connected to the prime mover while the rotor has a shaft bolted to it. This shaft is further connected to the driven machine through a suitable arrangement. Oil is filled in the fluid coupling from the filling plug provided on its body. A fusible plug is provided on the fluid coupling which blows off and drains out oil from the coupling in case of sustained overloading.

Operating Principle

There is no mechanical inter-connection between the impeller and the rotor and the power is transmitted by virtue of the fluid filled in the coupling. When the impeller is rotated by the prime mover, the fluid flows out radially and then axially under the action of centrifugal force. It then crosses the air gap to the runner and is directed towards the bowl axis and back to the impeller. To enable the fluid to flow from impeller to rotor it is essential that there is difference in head between the two and thus it is essential that there is difference in RPM known as slip between the two. Slip is an important and inherent characteristic of a fluid coupling resulting in several desired advantages. As the slip increases, more and more fluid can be transferred. However when the rotor is at a standstill, maximum fluid is transmitted from impeller to rotor and maximum torque is transmitted from the coupling. This maximum torque is the limiting torque. The fluid coupling also acts as a torque limiter.

Characteristics

Fluid coupling has a centrifugal characteristic during starting thus enabling no-load start-up of prime mover, which is of great importance. This feature also provides inherent overload protection. The slipping characteristic of fluid coupling provides a wide range of choice of power transmission characteristics. By varying the quantity of oil filled in the fluid coupling, the normal torque transmitting capacity can be varied. The maximum torque or limiting torque of the fluid coupling can also be set to a pre-determined safe value by adjusting the oil filling. The fluid coupling has the same characteristics in both directions of rotation.

The losses in this system are circulation and slip losses. Circulation losses are a constant percentage of the rated capacity of the unit—typically 1.5%. Slip losses are the product of torque output and slip speed (motor speed minus load speed). If the slip speed increases significantly, a higher motor rating, or a motor designed for high slip may have to be selected.

v. Variable Pitch Drives Description

This method of speed control uses the mechanical means of belts and variable pitch

sheaves or pulleys to change speed. The power source is a standard induction motor. Often these units are enclosed and have a gear reducer built in for reduced speed ranges. The horse power range is generally limited from 5 to 50HP with not much available outside of that range.

Variable Pitch Features

First cost–These systems are among the lowest cost methods of achieving variable speed.

Simplicity–The principle of operation is well known and easy to understand. Also the construction is simple.

Variable Pitch Disadvantages

Control–Remote control is not an inherent feature. Since the drive uses mechanical means to vary the speed, electrical control signals must be adapted to existing mechanical controls.

Belt wear–The stress of variable speed operation requires periodic checks and replacement of the belts.

High inertia loads – This condition may cause problems. It may require over sizing the drive or custom motors. Special shutdown and start up procedures may be required to prevent overloading the motor.

Sheave Wear–running at a constant speed for extended periods of time may cause grooving in the sheaves. This degrades speed control and decreases belt life.

Motor Speed Control Systems

Multi-speed motors

Motors can be wound such that two speeds, in the ratio of 2:1, can be obtained. Motors can also be wound with two separate windings, each giving 2 operating speeds, for a total of four speeds. Multi-speed motors can be designed for applications involving constant torque, variable torque, or for constant output power. Multi-speed motors are suitable for applications, which require limited speed control (two or four fixed speeds instead of continuously variable speed), in which cases they tend to be very economical. They have lower efficiency than single-speed motors

Direct Current Drives (DC)

The DC drive technology is the oldest form of electrical speed control. The drive system consists of a DC motor and a controller. The motor is constructed with armature and field windings. Both of these windings require a DC excitation for

motor operation. Usually the field winding is excited with a constant level voltage from the controller.

Then, applying a DC voltage from the controller to the armature of the motor will operate the motor. The armature connections are made through a brush and commutator assembly. The speed of the motor is directly proportional to the applied voltage.

The controller is a phase controlled bridge rectifier with logic circuits to control the DC voltage delivered to the motor armature. Speed control is achieved by regulating the armature voltage to the motor. Often a tachogenerator is included to achieve good speed regulation. The tachogenerator would be mounted on the motor and produces a speed feedback signal that is used within the controller.

Wound Rotor AC Motor Drives (Slip Ring Induction Motors)

Wound rotor motor drives use a specially constructed motor to accomplish speed control. The motor rotor is constructed with windings which are brought out of the motor through slip rings on the motor shaft. These windings are connected to a controller which places variable resistors in series with the windings. The torque performance of the motor can be controlled using these variable resistors. Wound rotor motors are most common in the range of 300 HP and above.

Slip Power Recovery Systems

Slip power recovery is a more efficient alternative speed control mechanism for use with slip-ring motors. In essence, a slip power recovery system varies the rotor voltage to control speed, but instead of dissipating power through resistors, the excess power is collected from the slip rings and returned as mechanical power to the shaft or as electrical power back to the supply line. Because of the relatively sophisticated equipment needed, slip power recovery tends to be economical only in relatively high power applications and where the motor speed range is 1:5 or less.

Application of Variable Speed Drives (VSD)

Although there are many methods of varying the speeds of the driven equipment such as hydraulic coupling, gear box, variable pulley etc., the most possible method is one of varying the motor speed itself by varying the frequency and voltage by a variable frequency drive.

Concept of Variable Frequency Drive

The speed of an induction motor is proportional to the frequency of the AC voltage

applied to it, as well as the number of poles in the motor stator. This is expressed by the equation:

$$\text{RPM} = (f \times 120) / p$$

Where f is the frequency in Hz, and p is the number of poles in any multiple of 2.

Therefore, if the frequency applied to the motor is changed, the motor speed changes in direct proportion to the frequency change. The control of frequency applied to the motor is the job given to the VSD.

The VSD's basic principle of operation is to convert the electrical system frequency and voltage to the frequency and voltage required to drive a motor at a speed other than its rated speed. The two most basic functions of a VSD are to provide power conversion from one frequency to another, and to enable control of the output frequency.

Need for VFD

Earlier motors tended to be over designed to drive a specific load over its entire range. This resulted in a highly inefficient driving system, as a significant part of the input power was not doing any useful work. Most of the time, the generated motor torque was more than the required load torque.

In many applications, the input power is a function of the speed like fan, blower, pump and so on. In these types of loads, the torque is proportional to the square of the speed and the power is proportional to the cube of speed. Variable speed, depending upon the load requirement, provides significant energy saving. A reduction of 20% in the operating speed of the motor from its rated speed will result in an almost 50% reduction in the input power to the motor. This is not possible in a system where the motor is directly connected to the supply line. In many flow control applications, a mechanical throttling device is used to limit the flow. Although this is an effective means of control, it wastes energy because of the high losses and reduces the life of the motor valve due to generated heat.

Principles of VFD's

The VFD is a system made up of active/passive power electronics devices (IGBT, MOSFET, etc.), a high speed central controlling unit and optional sensing devices, depending upon the application requirement. A typical modern-age

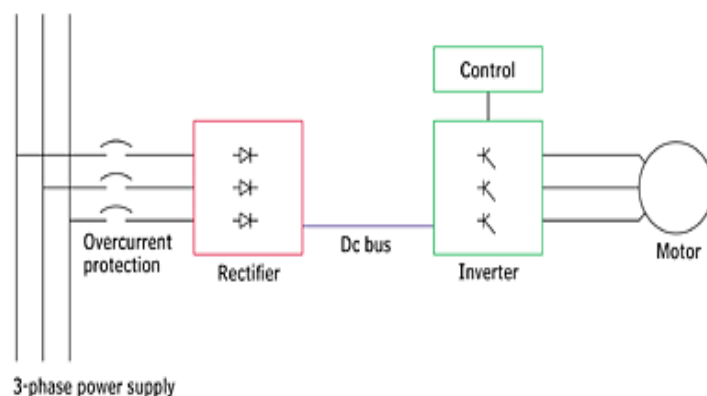


Figure: 2.10 Components of a Variable Speed Drive

intelligent VFD for the three phase induction motor is shown in Figure 2.10.

The basic function of the VFD is to act as a variable frequency generator in order to vary speed of the motor as per the user setting. The rectifier and the filter convert the AC input to DC with negligible ripple. The inverter, under the control of the microcontroller, synthesizes the DC into three-phase variable voltage, variable frequency AC.

The base speed of the motor is proportional to supply frequency and is inversely proportional to the number of stator poles. The number of poles cannot be changed once the motor is constructed. So, by changing the supply frequency, the motor speed can be changed. But when the supply frequency is reduced, the equivalent impedance of electric circuit reduces. This results in higher current drawn by the motor and a higher flux. If the supply voltage is not reduced, the magnetic field may reach the saturation level. Therefore, in order to keep the magnetic flux within working range, both the supply voltage and the frequency are changed in a constant ratio. Since the torque produced by the motor is proportional to the magnetic field in the air gap, the torque remains more or less constant throughout the operating range.

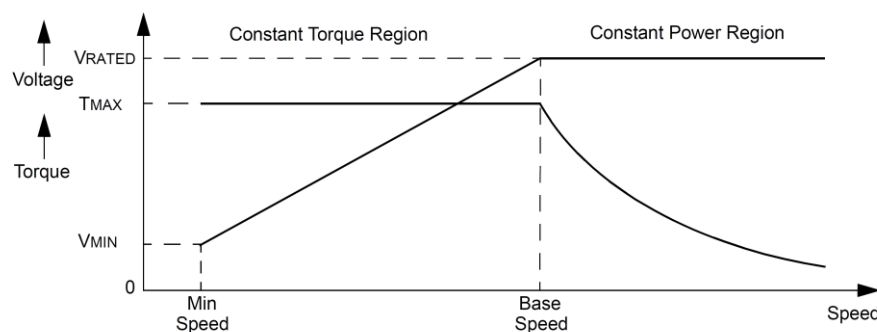


Figure 2.11: V/f Control

As seen in Figure 2.11, the voltage and the frequency are varied at a constant ratio up to the base speed. The flux and the torque remain almost constant up to the base speed. Beyond the base speed, the supply voltage cannot be increased. Increasing the frequency beyond the base speed results in the field weakening and the torque reduces. Above the base speed, the torque governing factors become more nonlinear as the friction and wind age losses increase significantly. Due to this, the torque curve becomes nonlinear. Based on the motor type, the field weakening can go up to twice the base speed. This control is the most popular in industries and is popularly known as the constant V/f control.

By selecting the proper V/f ratio for a motor, the starting current can be kept well

under control. This avoids any sag in the supply line, as well as heating of the motor. The VFD also provides over current protection. This feature is very useful while controlling the motor with higher inertia. Since almost constant rated torque is available over the entire operating range, the speed range of the motor becomes wider. User can set the speed as per the load requirement, thereby achieving higher energy efficiency (especially with the load where power is proportional to the cube speed). Continuous operation over almost the entire range is smooth, except at very low speed. This restriction comes mainly due to the inherent losses in the motor, like frictional, wind age, iron, etc. These losses are almost constant over the entire speed. Therefore, to start the motor, sufficient power must be supplied to overcome these losses and the minimum torque has to be developed to overcome the load inertia.

A single VFD has the capability to control multiple motors. The VFD is adaptable to almost any operating condition.

VFD Selection

The size of the VFD depends mainly on driven load type and characteristics. This will determine the drive capacity in terms of full load current (FLC) and power delivered (kW).

Driven Load Types and Characteristics

Mechanical load, which is the load on the motor shaft, can be of two types- Constant Torque (CT) or Variable Torque (VT). There is a basic difference between the two loads with respect to load torque variation at different speeds.

A CT load implies that the load torque seen at motor shaft is independent of motor speed.

This means that the load torque remains approximately the same at all speeds. Examples of CT loads include material handling conveyers, reciprocating & screw compressors and certain types of blowers such as roots blower.

A VT load implies that the load torque seen at the motor shaft is dependent upon the motor speed.

Examples of VT loads include centrifugal fans & pumps and centrifugal compressors.

The graphs (Figures 2.12 & 2.13) below describe the torque requirements at various speeds.

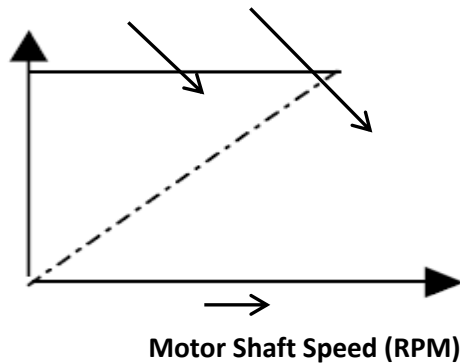


Figure 2.12 A CT load characteristic

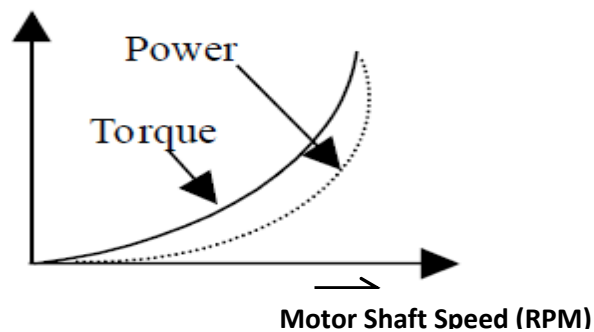


Figure 2.13 A VT load characteristic

Variable Frequency Drives: Precautions

- **Ensure that the power voltage** supplied to VFDs is stable with inplusorminus10% to prevent tripping faults.
- **Motors operating at low speeds** can suffer from reduced cooling. For maximum protection on motors to be run at low speeds, install thermal sensors that inter lock with the VFD control circuit. Standard motor protection responds only to over-current.
- **Speed control wiring**, which is often 4 mA to 20 m A or 0 VDC to 5 VDC, should be separated from other wiring to avoid erratic behavior. Parallel runs of 115V and 24 V control wiring may cause problems.
- **Precautions** for specifying, installing and operating VFDs are numerous. Improper installation and start-up accounts for 50 % of VFD failures
- **Use the VFD start-up sheet** to guide the initialization check prior to energizing the VFD for the first time.
- **Corrosive environments**, humidity above 95%, ambient air temperatures exceeding 40⁰C (104⁰F), and conditions where condensation occurs may damage VFDs.
- **If a VFD is started** when the load is already spinning, the VFD will try to pull the motor down to a low, soft-start frequency. This can result in high current and a trip unless special VFDs are used.
- **Switching from grid power** to emergency power while the VFD is running is not possible with most types of VFDS. If power switching is anticipated, include this capacity in the specification.
- **If electrical disconnects** are located between the VFD and motor, interlock the run- permissive circuit to the disconnect.
- **If a motor always operates at rated load**, aVFD will increase power use, due to electrical losses in the VFD.

2.6.8 Harmonics

A key concern with VSD operation is the generation of harmonics-multiples of the fundamental frequency (50Hz) which result in an on-sinusoidal high for in verters with only a few pulses per second as compared to more complex ones that produce a 12-step (or higher) voltage waveform or that employ pulse width modulation.

Harmonics increase motor losses, and can adversely affect the operation of sensitive auxiliary equipment. Then on-sinusoidal supply results in harmonic currents in the stator which increases the total current draw. In addition, the rotor resistance (or more precisely impedance) increases significantly at harmonic frequencies, leading to less efficient operation. Also, stray load losses can increase significantly at harmonic frequencies. Overall motor losses increase by about 20% with a six-step voltage wave form compared to operation with a sinusoidal supply. In some cases the motor may have to be de rated as a result of the losses. Alternatively, additional circuitry and switching devices can be employed to minimize losses.

Motor instability, characterized by hunting of the rotor (a phenomenon where the rotor accelerates or decelerates about a stable speed), may occur for certain critical frequency ranges and loading conditions. Motors are inherently unstable at low frequencies. Instability can also occur due to the interaction between the motor and the converter. This is especially true of motors of low rating, which have low inertia. Instabilities can be reduced by changing the machine parameters (e.g., motor impedance) or by employing closed loop feedback systems. The VSD supplier should be consulted to ascertain the impact of inverters on motor performance.

Harmonics can also contribute to low power factor. Shunt capacitors that might be used to compensate for low power factor also generate harmonics. If parallel resonance occurs between the shunt capacitor and VSD (at frequency determined by the capacitance and system inductance), the voltage wave form may undergo significant distortion causing motor overheating, capacitor failure or mis-operation of the control. To avoid resonance, reactive filters can be designed for the VSD. Filters are designed to eliminate resonance at the fifth and seventh frequency harmonics which are the most harmful⁷. Low level distortions may still be present, but these do not pose a serious problem.

2.6.9 Other operating concerns

Steep voltage transients, e.g. caused by switching of shunt capacitors or transient system faults, can affect VSD operation. Isolation transformers or special VSD inverter designs can be used to prevent such transients from tripping or otherwise

affecting VSD operation. A power supply with unstable voltage and frequency also hampers regenerative braking, thus eroding efficiency.

When a totally-enclosed fan-cooled motor is controlled to operate at very low speed, some de rating may be required if the cooling is inadequate.

In cases where some of the operating time is at close to rated load, system efficiency might be increased by using a bypass arrangement to avoid the losses in the VSD. The VSD would be engaged at lower loads, when the VSD-related reductions in power would more than off-set in efficiencies of the VSD. Such a bypass arrangement would also provide for greater reliability in case of a VSD failure.

2.6.10 Transmission Efficiency

Power transmission equipment linking motors to driven machines including shafts, belts, chains, and gears should be properly selected, installed and maintained. When possible, use flat belts in place of V-belts. Helical gears are more efficient than worm gears; use worm gears only with motors under 10hp. As far as possible it is better to have a direct drive thus avoiding losses in motor power transmission to the driven machine.

Power transmission Efficiency margin from V belt drive flat belt drive 5 to 6 % and from Worm gearbox to Helical Gearbox 8 to 10 %

2.6.11 Soft Starters

A soft starter is another form of reduced voltage starter for A.C. induction motors which facilities gradual acceleration of motor and consequent elimination of shocks during starting (soft start). The starting current with a soft starter is only 1.5 to 2 times the full load current as against 5–7 times in the case of other conventional starters. Because of this cable sizes, contact or sand motors can be sized lower during the initial selection. The soft starter is similar to a primary resistance or primary reactance starter in that it is in series with the supply to the motor. The current into the starter equals the current out. The soft starter employs solid state devices to control the current flow and therefore the voltage applied to the motor.

Working of Soft Starter / Energy Saver

- i. The soft-start motor starter combines the advantages of reduced voltage starting and reduced energy consumption, in one compact economical package. Because they are solid state, burnout of starter parts are eliminated. The reduced voltage starter gracefully increases motor voltage from the set

minimum voltage to full voltage allowing the motor to smoothly and gradually accelerate to full speed, when it is set on soft-start mode.

- ii. The soft starter offers a ramp input voltages source to a motor which can be programmable, and this factor is the essence of soft starting as against conventional step voltage starter or D.O.L. starter.

Advantages:

- Nanosecond response on account of micro-electronics involved.
- Reduced power consumption and hence reduced energy bills, at part loads. Power factor improvement on a continuous basis
- Reduction in maximum demand
- Reduced peak motor current during starting
- Reduced motor temperature, increased motor life and decreased maintenance needs
- When using a generator, the power generated can be used to operate more equipment, since the starting and running currents of motors are lower, when motors are fitted with energy-saver-soft-starters.

Typical Applications

Plastic injection moulding machines, Machine tools / motor generator welding sets, chemical process equipments, unloading type air compressors, punch presses, center less grinding and polishing machines, blowers, wherever the motor load is varying continuously.

1.16. CASE STUDIES

CASE STUDY- 1

Based on study of humidification plants in a Rayon industry, it was established that the air flow demand in supply air and return air varies as per season and the supply and return fans rated 16 kW, 12 kW respectively were running at constant load. Towards energy efficiency improvement, the drives were converted variable frequency drives. The part load effects are summarized as follows:

Supply Frequency C/S	Supply Air Fan		Return Air Fan	
	KW Drawn	% Drop in	KW Drawn	% Drop in
50	16.4	Capacity Ref.	12	Capacity Ref.
45	12.0	10.0	8.7	10.0

40	8.4	20.0	6.1	20.0
35	5.6	30.0	4.1	30.0
30	3.5	40.0	2.6	40.0

As the flow requirements vary, the following schedule was adopted with power savings indicated alongside.

Months	Recommended Frequency	Average %kW Savings
October, Nov, Dec, Jan	35	51
Feb, March, Sept.	40	35
April, August, July	45	18
May, June	50	-

Covering all 10fans, with 142kW consumption among five sets of supply air & return air fans, the savings achieved were 3 77223kWh worth BDT.13.16lakhs/yea against an investment of BDT12.5lakhs @BDT1.25lakh/ drive yielding a simple payback period of less than one year.

CASE STUDY-2

Refrigeration plant study in a chemical complex indicated part load operation of reciprocating compressor drives with un loader mechanism, as illustrated below:

Item Reference	Brine Unit	Chilled Water Unit
Motor input kW	53	74.1
Rpm	750	780
Op. hours / day	14.5	9.0
% ON time	58	38
Power consumption/day (kWh)	768.5	666.9

The Compressor speed can be increased or decreased with a change in the drive pulley or the driven pulley or in some cases, both pulleys. By pulley diameter modification, the machines were de-rated to match required capacity. A higher sized reciprocating compressor operating with higher unloading percentage was downsized by reducing the motor (drive) pulley size from 12" to 7.5" in case of Brine unit and 12" to 6" in case of Chilled water unit .

Despite increased use hours due to de rating effects, the specific power consumption reduced as the evaporator and condenser became oversized for the de-rated condition, and the energy consumption reduced as well as follows:

Item Reference	Brine Unit	Chilled Water Unit
Motor input kW	32.3	35.6
Speed Rpm	480	409.5
Op. hours / day	18.0	14.0
Average energy consumption/day (kWh)	581.4	498.4

The energy savings of 355.6kWh/day by the simple modifications, are a significant 25%. The interesting part of the exercise was that the investment is nominated, and the pay back is in order of days. Most cases, where load-unload cycling of reciprocating machine takes place for capacity control, pulley diameter modification offers a simple, cheap solution to de rate the machine capacity with energy savings potential of significant order.

2. COMPRESSED AIRSYSTEMS

2.1. INTRODUCTION

Air compressors account for a significant amount electricity used in industrial sector. Air compressors are used in a variety of industries to supply process requirements, operate pneumatic tools and equipment, and for instrumentation. The generation efficiency is only about 10% as shown in the figure 3.1 and balance 90% of energy of the power of the prime mover being converted to unusable heat energy and to a lesser extent lost in form of friction, misuse and noise. Further considering the distribution efficiency, the overall efficiency can be as low as 6.5% when pressure drops, leaks, and part-load control losses are considered.

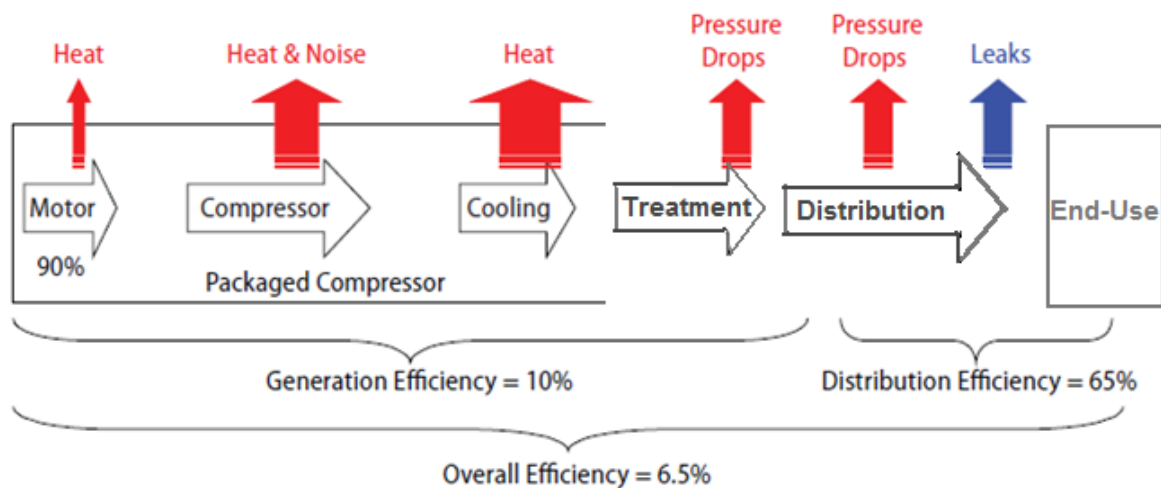


Figure 3.1: Efficiency of Compressed Air System

2.2. COMPRESSOR TYPES

Compressors are broadly classified as dynamic and positive displacement types.

Dynamic compressors are centrifugal compressors and are further classified as radial and axial flow types. Positive displacement compressors are further classified as reciprocating and rotary compressors, under which there are further sub-classifications.

Dynamic compressors increase the fluid's velocity, which is then converted to increased pressure at the outlet. Positive displacement compressors increase the pressure of the gas by reducing the volume. The flow and pressure requirements of a given application determine the suitability of a particular type of compressor.

2.3. POSITIVE DISPLACEMENT COMPRESSORS

3.3.1 Reciprocating Compressors

In industry, reciprocating compressors are the most widely used type for both air and refrigerant compression. They are characterized by a flow output that remains nearly constant over a range of discharge pressures. Also, the capacity is directly proportional to the speed. The output, however, is a pulsating one. Reciprocating compressors are available in many configurations, the four most widely used of which are horizontal, vertical, horizontal balance-opposed and tandem. Vertical type reciprocating compressors are used in the capacity range of 50–150 cfm. Horizontal balance opposed compressors are used in the capacity range of 200–5000 cfm in multi-stage design and up to 10,000 cfm in single stage designs. In

refrigeration cycles, reciprocating compressors are best suited for applications requiring up to 150 tone of refrigeration.

Reciprocating compressors are available in variety of types, such as single or multiple cylinder, single or multi stage, lubricated and non-lubricated, and water or air cooled. Non-lubricated compressors are especially useful for providing instrument air and for processes, which require oil free discharge. However non-lubricated machines have marginally higher specific power consumption (kW/cfm) as compared to lubricated models. In the case of lubricated machines, oil has to be separated from the discharge. Single cylinder machines are generally air-cooled while multi-cylinder machines are water cooled, though multi-stage air cooled models are available for machines up to 100 kW. Two stage machines are used for high pressures and are characterized by lower discharge temperature (140 – 160°C) compared to single-stage machines (205 – 240°C). In some cases, multi-stage machines may have a lower specific power consumption compared to single stage machines operating over the same total pressure differential. Multi-stage machines generally have higher investment costs, particularly for applications with high discharge pressure (up to 7 bar) and low capacities (less than 25cfm). Multi staging has other benefits, however, including a reduced pressure differential across cylinders, which reduces the load and stress on valves and piston rings.

3.3.2 Rotary Compressors

Rotary compressors have rotors in place of pistons and give a continuous, pulsation free discharge. They operate at high speed and generally provide higher throughput than reciprocating compressors. They are directly coupled to the prime mover and require lower starting torque as compared to reciprocating machines. Also they do not require specialized foundations, operate with limited vibration, and have a lower number of parts - which means less failure rate. Among rotary machines, the lobe compressor (also known as a Roots blower) and screw compressors are among the most widely used. The lobe compressor is essentially a low pressure blower and is limited to a discharge pressure of 1bar in single-stage design and up to 2.2 bar in two stage design. Screw compressors are high speed, high capacity machines and are available in both dry and oil injected types with single or twin screw compressors deliver oil-free air and are available in sizes upto 20,000cfm and pressure upto 15 bar, and in the size range of 100 – 1000cfm in lubricated designs upto 10 bar discharge pressure. They cannot operate at discharge pressures below 3.5 bar. In the case of oil injected (lubricated) rotary screw compressors, oil has to be separated from the discharged air (gas). In refrigeration systems, screw compressors are preferable for intermediate temperatures (10 to 50°C).

Other types of rotary compressors such as rotary vane and liquid-ring compressors are also available. Rotary vane compressors are small in size and have a pulsation-free output. The two common types of rotary vane compressors are oil-flooded with non-metallic blades and water-cooled with steel blades. Both designs have many of the advantages of the oil injected screw compressor and are generally designed as multi-stage machines. Single-stage designs are available for discharge pressures upto 7 bar. Liquid ring compressors operate on the same principle as rotary vane compressors. They have comparatively high power consumption and are generally designed for discharge pressures up to 5.5 bar.

2.4. CENTRIFUGAL COMPRESSORS

Centrifugal compressors have appreciably different characteristics as compared to reciprocating machines. A small change in compression ratio produces a marked change in compressor output and efficiency. They operate on the same principle as centrifugal pumps. Centrifugal machines are less efficient than reciprocating machines, but are better suited for applications requiring very high capacities, typically above 12,000cfm in the case of air(gas) compression, and for high capacity (150–5800 tons), low temperature (10–100°C) refrigeration applications. Centrifugal machines are low in initial cost and compact in size for large capacity requirements (a single - stage centrifugal machine may provide the same capacity as a multi-stage reciprocating compressor). Machines with either radial or axial flow impellers are available. Axial compressors have characteristics similar to positive displacement compressors. Also, they are suitable for higher compression ratios and are 5–10 % more efficient than radial compressors. Axial compressors typically are multi-stage machines while radial machines are usually single-stage designs.

Table 3.1: General Selection Criteria for Compressors

Type of Compressor	Capacity (m ³ /h)		Pressure(bar)	
	From	To	From	To
Roots power compressor single stage	100	30000	0.1	1
Reciprocating				
- Single / Two stage	100	12000	0.8	12
- Multi stage	100	12000	12.0	700
Screw				
- Single stage	100	2400	0.8	13
- Two stage	100	2200	0.8	24
Centrifugal	600	300000	0.1	450

Comparison of Different Compressors

The power consumption of various compressors depends on the operating pressure, free air delivery and efficiency etc. The variations in power consumption during unloading/part load operation are more significant and depend on the type of compressor and method of capacity control. The relative efficiencies and part load power consumption of different compressors are given in Table 3.2

Table 3.2 Comparison of Different Compressors				
Item	Reciprocating	Rotary vane	Rotary Screw	Centrifugal
Efficiency at full load	High	Medium-high	High	High
Efficiency at part load	High due to staging	Poor: below 60% of full load	Poor: below 60% of full load	Poor: below 60% of full load
Efficiency at no load (power as % of full load)	High (10-25%)	Medium (30-40%)	High-poor (25-60%)	High-medium (20-30%)

In case of reciprocating machines, the unload power consumption is in the order of 25% of full load power. While in screw compressors, the unload power consumption is marginally higher compared to reciprocating machines.

It is preferable to use screw compressors for constant air requirement. If screw compressors have to be installed for fluctuating loads, it is desirable to have screw compressor with variable speed drive to further optimize unload power consumption.

Some of the plants have adopted the strategy of operating screw compressor at full load for meeting the base-load requirement and reciprocating compressor for fluctuating load to optimize on unload power consumption.

2.5. SYSTEM COMPONENTS

Compressed air systems, depending on the requirement, consist of a number of components compressors filters, air dryers, inter-coolers, after coolers, oil separators, valves, nozzles, and piping.

- **Intake Air Filters:** Prevent dust and atmospheric impurities from entering compressor. Dust causes sticking valves, scored cylinders, excessive wear etc.
- **Inter-stage Coolers:** Reduce the temperature of the air(gas) before it enters the next stage to reduce the work of compression and increase efficiency. They can be water-or air-cooled.
- **After Coolers:** Reduce the temperature of the discharge air, and thereby reduce the moisture carrying capacity of air.
- **Air-dryers:** Air dryers are used to remove moisture, as air for instrument and

pneumatic equipment needs to be relatively free of any moisture. The moisture is removed by using adsorbents or refrigerant dryers, or state of the art heatless dryers.

- **Moisture Traps:** Air traps are used for removal of moisture in the compressed air distribution lines. They resemble steam traps where in the air is trapped and moisture is removed.
- **Receivers:** Depending on the system requirements, one or more air receivers are generally provided to reduce output pulsations and pressure variations.

2.6. COMPRESSOR PERFORMANCE

Capacity of a Compressor: Free Air Delivery (FAD)

Free air, as defined by CAGI (Compressed Air & Gas Institute) is air at ATMOSPHERIC conditions at any specific location. Because the barometer and temperature may vary at different localities and at different times, it follows that this term does not mean air under standard conditions.

Measured in CFM (Cubic feet per minute) this is the amount of compressed air converted back to the actual inlet (free air) conditions before it was compressed. In other words, the volume of air, which is drawn in from the atmosphere by the compressor, then compressed and delivered at a specific pressure.

Compressor Efficiency Definitions

Compressor efficiency is often expressed as either an adiabatic or is other mechanical efficiency. These are computed as the is other mechanical power respectively, divided by the actual power consumption. The calculation of is other mechanical power excludes that needed to overcome friction and generally gives an efficiency that is lower than an adiabatic efficiency. This is an important consideration when selecting compressors based on reported values of efficiency. Manufacturers generally provide the adiabatic (theoretical) horse power required for compression. The actual power intake would be slightly higher because of mechanical losses.

For practical purposes, the most effective guide in comparing compressor efficiencies is the specific power consumption for different compressors that would provide identical duty.

Isothermal Efficiency

The Iso-thermal efficiency of a multi-stage air compressor can be calculated as a ratio of the theoretical kW required for a duty conditions and the actual kW input measured. This efficiency would reflect the combined efficiency of the compressor and the drive motor and the method can be adopted to assess the performance for

identifying margins with respect to rated values, merit rating of compressors, maintenance planning, etc.

$$\text{Theoretical kW} = \left(\frac{NK}{K-1} \right) \left(Q \frac{P_s}{0.612} \right) \left[\left(\frac{P_d}{P_s} \right)^{\frac{K-1}{NK}} - 1 \right]$$

N = No. of stages

K = Ratio of specific heats (1.35 for air)

P_s = suction pressure in kg/cm²

P_d = Discharge pressure in kg/cm²

Q = Actual air flow (m³/min.) Actual kW = $\sqrt{3} V I \times \text{PF}$ as measured

$$\text{Efficiency of compressor and motor combination} = \frac{100 \times \text{Theoretical kW}}{\text{Actual kW}}$$

It is also a done thing, to compute and add-up stage wise work of compression (theoretical kW) in case the performance of intercoolers is not optimal.

Volumetric Efficiency

$$\text{Volumetric efficiency} = \frac{\text{Free air delivered (m}^3/\text{min)}}{\text{Compressor displacement (m}^3/\text{min)}} \times 100$$

$$\text{Compressor Displacement} = \frac{\pi}{4} \times D^2 \times L \times S \times \chi \times n$$

D	=	Cylinder bore, metre
L	=	Cylinder stroke, metre
S	=	Compressor speed rpm
χ	=	1 for single acting and 2 for double acting cylinders
n	=	No. of cylinders

2.7. EFFICIENT COMPRESSOR OPERATION

3.7.1 Reciprocating Compressors

The capacity of reciprocating compressors can be controlled by throttling suction or

discharge pressure, by using the cylinder expansion (clearance) volume, by passing gas externally, using cylinder run-loaders, or by speed control. External by pass involves feeding some of the output back to the suction (the gas may have to be cooled before being fed back to the compressor). Though this method can provide 0 – 100 % capacity control, it does not result in any significant power reduction at reduced flow. However, at very low capacities, gas bypass is generally the only solutions inciter methods may result in unstable operation. Throttling in another alternative, but saves relatively little energy. The most common and more efficient method is to employ automatic or manual cylinder un-loaders or to use clearance pockets in the cylinder. Reduction in power consumption is proportional to capacity control. The most efficient method of controlling capacity, however, is to vary the speed of the prime movers since capacity is directly proportional to the speed.

The performance of reciprocating compressors varies based on the altitude, inlet air (gas) temperature, discharge pressure, the effectiveness of inter stage cooling and operational speed. Increase in altitude, with the result ant reduction in pressure, increases the compression ratio leading to higher discharge temperature and reduced efficiency. However, for a given compressors ratio, the specific power requirement, which varies directly with the suction pressure, decreases with an increase in altitude. The effect of altitude on multi- staged compressors is slight.

The discharge pressure should be kept at the minimum required for the process or for operation of pneumatic equipment for a number of reasons, including minimizing power consumption. Also, compressor capacity varies inversely with discharge pressure. Another disadvantage of higher discharge pressures is the increased loading on compressor piston rods and their subsequent failure. Lower pressure also results in lower leakage losses. In general, when compressing gas starting at ambient temperature and pressure through a pressure ratio exceeding 4, multistage compression with inter cooling should be considered to maintain the temperature of the compressed gas.

Multi-stage compressors are usually provided with inter coolers to reduce the temperature of the air (gas) discharged between stages. Ideally, the intake temperature a teach stage should be the same as that at the first stage (referred to a perfect cooling) so that the volume of air to be compressed does not increase. The provision of well- designed inter cooling systems reduces power consumption. However, use of very cold water can result in condensation which may result in water can result in condensation which may result in water entering the cylinder, thereby reducing valve life, accelerating wear and scoring of piston, piston rings and cylinder. Condensation can also occur when the relative humidity of inlet air is high and the compressor cylinder temperature is lower than inlet air temperature (for

example, as a result of higher than required flow of cooling water). The condensed water may also wash away the oil film on the cylinder and cause rust which will result in a abrasion during compressor operation and significantly reduce efficiency. At the other extreme, if cooling is insufficient, the discharge temperature increases. High temperature operation reduces oil viscosity and the oil film thickness can be reduced.

The location of the compressor should be considered during the selection process. Locations with high moisture or high temperature can cause operational trouble and increase power consumption. Cooling should be adequate in such cases. When locating the suction inside buildings, care should be taken to ensure adequate clearance between the suction and the walls to reduce pulsation and vibrations.

3.7.2 Centrifugal Compressors

Manufacturers specify discharge pressure and power requirement as a function of the inlet volumetric flow rate. These performance curves are valid at only the given inlet conditions. Therefore, to optimize process efficiency and to predict performance at different process and inlet conditions, performance curves which provide the polytropic head and polytropic efficiency as a function of the inlet volume flow is useful for such analysis. The manufacturer should be consulted in such cases.

The major limitation of a centrifugal compressor is that it operates at peak efficiency at design point only and any deviation from the operating point is detrimental to its performance. When selecting centrifugal compressors, close attention should be paid during system design to ensure that at high pressure, with the consequent reduction in flow, the surge point is not reached. Surge point is the point on the performance curve where a further decrease in flow (typically in the region of 50 - 70 % of rated capacity) causes instability, resulting in a pulsating flow, which may lead to overheating, failure of bearings due to thrust reversals, or excessive vibration. Bypass valves are commonly used to prevent surging.

Using variable inlet-guide vanes, throttling of suction pressure or throttling of discharge pressure can control the output of centrifugal compressors. However, since centrifugal compressors follow the same affinity laws as centrifugal pumps another efficient way to match compressor output to meet varying load requirements is through speed control.

3.7.3 Screw Compressors

The capacity of screw compressors is normally controlled by a hydraulically

operated slide valve, which by passes gas without compression. However, speed control is the most efficient means of capacity control. Unlike reciprocating and centrifugal compressors, screw compressors develop full pressure regard less of speed. Also, they are more stable at low capacity (upto10%load)–unlike centrifugal compressors which surge at capacities lower than about 50% of the rated value. The volume handled and the power consumption are directly proportional to speed. Therefore, variable speed drives can be used to efficiently control capacity. Part load power consumption of screw compressors is generally higher than that for reciprocating and centrifugal compressors. Additionally, the discharge pressure of the screw compressor should be closely matched to discharge line pressure to avoid over or under compression that result in higher power consumptions. Therefore, when considering screw compressors, the volume ratio should be properly specified.

2.8. ENERGY EFFICIENCY PRACTICES IN COMPRESSED AIRSYSTEMS

3.8.1 Location of Compressors

Location of air compressors and the quality of air drawn by the compressors will have a significant bearing on the amount of energy consumed. Compressor performance as a breathing machine improves with cool, clean, dry air at intake.

Cool air intake

Every 4°C rise in inlet air temperature results in a higher energy consumption by 1% to achieve equivalent output. Hence, cool air intake leads to a more efficient compression.

Table 3.3: Effect of Intake Air temperature on Power Consumption

Inlet Temperature(°C)	Relative Air Delivery (%)	Power Saved (%)
10.0	102.0	+1.4
15.5	100.0	Nil
21.1	98.1	- 1.3
26.6	96.3	- 2.5
32.2	94.1	- 4.0
37.7	92.8	- 5.0
43.3	91.2	- 5.8

It is preferable to draw cold ambient air, as the temperature of air inside the compressor room will be a few degrees higher than the ambient temperature. A sheltered inlet, protected from rain on a north wall is desirable. While extending air intake to the outside of building, care should be taken to minimize excess pressure

drop in the suction line, by selecting a bigger diameter duct with minimum number of bends.

3.8.2 Dust Free Air Intake

Dust in the suction air causes excessive wear of moving parts and results in malfunctioning of the valves due to abrasion. Suitable air filters should be provided at the suction side. Air filters should have high dust separation capacity, low pressure drops and robust design to avoid frequent cleaning and replacement.

Table 3.4: Effect of Pressure Drop across Air Inlet Filter on Power consumption

Pressure Drop Across air filter	Increase in Power Consumption (%)
0	0
200	1.6
400	3.2
600	4.7
800	7

Air filters should be selected based on the compressor type and installed as close to the compressor as possible. For every 25mbar pressure lost at the inlet due to choked filters, the compressor performance is reduced by about 2percent. Hence, it is advisable to clean inlet air filters at regular intervals to avoid high-pressure drops. Manometers or differential pressure gauges across filters may be provided for monitoring pressure drops so as to plan filter-cleaning schedules.

Table 3.5: Comparison of Inlet Air Filters

Type	Filter Action Efficiency, %	Particle Size, Microns	Pressure Drop when Clean, inches of Water Column	Comments
Dry	100 99 98	10 5 3	3 to8	Recommended for non-lubricated compressors in a high dust environment
Dry type with Silencer	100 99	10 5	5 7	Same as above
Oil wetted (viscous impingement)	95 85	20 10	0.25 to 2.0	Not recommended for dusty areas or for non-lubricated

Oil bath	98 90	10 3	2 6 to10	Same as above. Recommended for rotary vane compressors in normal service

3.8.3 Dry Air Intake

% Relative Humidity	Kg of water vapour compressed per hour for every 1000 m ³ /min. of air at 30°C
50	27.6
80	45
100	68.22

Table 3.6: Moisture Levels at Various Humidity Levels

Atmospheric air always contains some amount of water vapour, depending on the relative humidity, being high in foggy or rainy weather. The moisture level will also be high if air is drawn from a damp area, cooling tower exhaust and air conditioner warm outlet air.

It is desirable to draw in air with a lower lative humidity, as otherwise, energy is consumed to compress the water vapour in the air and again to condense and drain the moisture from inter and after coolers. The moisture-carrying capacity of air increases with arise in temperature and decreases with increase in pressure.

3.8.4 Pre-Cooled Air Intake

By cooling the air entering the compressor, the efficiency of the compressor can be improved. This cooling, usually to25⁰C is achieved by refrigeration, if the chilled water is available at cheap cost. As the temperature of air is reduced, its volume decreases and a greater mass of air is available for the given compressor. Therefore, due to pre-cooling either more air is delivered for a given power input or the power input is reduced for a required volumetric flow rate. Using pre-cooled dry air can save about 20– 30 % of compressor power requirement. Also, the moisture present inlet air is condensed out giving dry air for compression and saving energy which would otherwise be used for compressing water vapour.

After-coolers and dryers are also eliminated as the pre-cooler performs their functions. This represents another capital cost saving as well as an additional energy saving device. However the economics of cooling the air using chilled water must be viable considering the cost of chilled water available and energy savings in

the compressor due the reduced in take air temperature.

3.8.5 Elevation

The altitude of a place has a direct impact on the volumetric efficiency of the compressor. The effect of altitude on volumetric efficiency is given below:

Table 3.7: Effect of Altitude on Volumetric Efficiency

Altitude Meters	Barometric Pressure	Percentage Relative Volumetric Efficiency Compared with Sea Level	
	Mbar	At 4 bar	At 7 bar
Sea level	1013	100	100
500	945	98.7	97.7
1000	894	97	95.2
1500	840	95.5	92.7
2000	789	93.9	90
2500	737	92.1	87

It is evident that compressors located at higher altitudes consume more power to achieve a particular delivery pressure than those at sea level, as the compression ratio is higher.

3.8.6 Cooling Water Circuit

Most of the industrial compressors are water-cooled, where in the heat of compression is removed by circulating cold water to cylinder heads, inter-coolers and after-coolers. The resultant warm water is cooled in a cooling tower and circulated back to compressors. The effect of cooling tower performance, total dissolved solids (TDS) in cooling water, pumps and fans on compressor performance is discussed below:

- **Cooling Tower Performance**

The main purpose of a cooling tower is to reduce the inlet warm water temperature to near the wet bulb temperature of ambient air. Cooling towers are generally designed to have an approach temperature of 2 to 5°C depending upon the type of cooling tower. In practice, because of microbial growth, scale formation, corrosion and improper maintenance, the intimate contact between air and water is disturbed, resulting in high temperature outlet water which will affect compressor inter cooler effectiveness and compressor performance. Proper maintenance of cooling tower is very important to achieve the desired approach temperature.

- **Effect of air wet bulb temperature on cooling tower performance**

The cooling tower performance is affected by atmospheric conditions—particularly by the wet bulb temperature of inlet air. In a given location, the wet bulb temperature changes throughout the year, reaching its peak value only occasionally. It would, therefore, be uneconomical to operate the tower designed on the basis of the maximum wet bulb temperature. A compromise between peak and average conditions has to be adopted. While designing or selecting a cooling tower, “5 %” wet bulb temperature is used which is, the wet bulb temperature not exceeded more than 5% of the total number of hours during summer months. This is estimated from the study of local meteorological data.

- **Cooling Tower Pump**

Cooling water is supplied to compressors through centrifugal pumps at a particular pressure and flow rate. Any change in water flow rate or pressure will affect the compressor performance. High efficiency pumps and motors have to be selected, as they run continuously. Inter connecting pipelines, inter-coolers, and after-coolers have to be selected or designed for minimum pressure drop. Generally pumps in a central compressor house are over-designed for safety reasons, and are capable of catering to more than one compressor. During lean seasons and night shift, only one or two compressors are in operation but cooling water is circulated through even in idle compressors. To avoid this waste of water supply, idle compressors should be closed or a water pressures witch fixed in the water line so that compressor can be tripped off whenever the cooling water pressure falls below a pre-set value.

- **Cooling Tower fans**

Cooling tower fans are provided to facilitate more air through put thus increasing cooling tower efficacy. A malfunction off an will result in less air to water ratio, change in air distribution pattern etc., which will affect the cooling tower performance. Hence, proper fan maintenance and fan energy management has to be adopted for lower energy consumption.

- Once the cooling water temperature approaches set temperature, the cooling tower fan can be switched off or operated intermittently by providing a interlock between water outlet temperature and fan operation.
- If two speed motors are used the cooling tower fan power requirement can be reduced substantially, whenever the ambient wet bulb temperature decreases.
- Automatic variable pitch propeller type fans and inverter type devices can be incorporated to permit variable fan speeds. These can track the cooling load for a constant outlet water temperature.
- Heavy fan blades made up of metals can be replaced with light weight, and aerodynamically designed blades such as FRP to reduce the initial torque

required and the power consumption.

- Speed control of cooling tower fans by fluid-coupling drives can decrease–power consumption in motors.

Cooling Water TDS

In most of the installations, raw water with high TDS is used for compressor cooling. Because of inadequate attention to water quality, the TDS levels may shoot up to unacceptable levels, due to water loss through evaporation, drift and other entertainment losses. This leads to increase of scaling in cylinder heads, inter-coolers and after-coolers, which reduces heat exchanger efficacy and compressor capacity. The scaling in compressor and inter connecting pipe lines not only reduce its effectiveness but also increases pressures drop and thus, water pumping power.

Table 3.8: Effect of Scaling on Pressure Drop and Inner Pipe Diameter

Scaling Thickness (mm)	Inside Diameter Reduced		Pressure Drop
	From (mm)	To (mm)	
0.4	64	63.2	6
0.8	64	62.4	14
1.2	64	61.6	21
4.7	64	54.6	134

Use of treated water or purging apportion of cooling water periodically can maintain TDS levels within acceptable limits. It is better to maintain the water pH by addition of chemicals, and avoid microbial growth by addition of fungicides and algacides.

3.8.7 Efficacy of Inter and After Coolers

Inter-coolers are provided between successive stage sofa multi-stage compressor to cool the air, reduce its specific volume and condense out excess water. This reduces the power requirement in consecutive stages. Ideally, the temperature of the inlet air at each stage of a multi-stage machine should be the same as it was at the first stage. This is referred to as “perfect cooling”. But in actual practice, because of fouled heat exchangers, due to scaling of dissolved solids in cooling water, the inlet air temperatures at subsequent stages are higher than the normal levels resulting in higher power consumption, as a larger volume is handled for the same duty.

Table 3.9: Effect of Inter-stage Cooling on Specific Power Consumption of a Reciprocating Compressor

Details	Imperfect Cooling	Perfect Cooling	Chilled Water Cooling
1 Stage inlet temperature ⁰ C	21.1	21.1	21.1
2 Stage inlet temperature ⁰ C	26.6	21.1	15.5

Capacity(m ³ /min)	15.5	15.6	15.7
Shaft Power (kW)	76.3	75.3	74.2
Specific energy consumption kW (m ³ /min)	4.9	4.8	4.7
Percent Change	+ 2.1	-	- 2.1

It can be seen from the table 3.9 that an increase of 5.5⁰C in the inlet to the second stage results in a 2% increase in the specific energy consumption. Use of cold water reduces power consumption. However, use of very cold water could result in condensation of moisture in the air leading to cylinder damage. An after-cooler is located after the final stage of the compressor to reduce air temperature and water content, as far as possible, before air enters the receiver. As time passes, dissolved solids in the cooling water coat the after-coolers, thereby reducing the heat transfer effectiveness. So, fouled after- coolers, allow warm, humid air in to the receiver, which causes more condensation in air receivers and distribution lines, which in consequence, leads to increased corrosion. Periodic cleaning of both heat exchangers and cylinder heads are therefore necessary.

Table 3.10: Table: Cooling Water Requirement

Compressor Type	Minimum quantity of Cooling Water required for 2.85 m ³ /min. FAD at 7 bar (lpm)
Single-stage	3.8
Two-stage	7.6
Single-stage with after-	15.1
Two-stage with after- cooler	18.9

Inter-cooler and after-cooler efficacy also depends upon the quantity of cooling water circulated through the heat exchanger.

3.8.8 Pressure Settings

- **Reducing Delivery Pressure:**

The power consumed by a compressor depends on its operating pressure and rated capacity. They should not be operated above their optimum operating pressures as this not only wastes energy, but also leads to excessive wear, leading to further energy wastage. The volumetric efficiency of a compressor is also less at higher delivery pressures. The possibility of down setting the delivery pressure should be explored by careful study of pressure requirements of various equipment, and the pressure drop in the line between the compressed air generation and utilization points. The pressure switches must be adjusted such that the compressor cut-in and cuts-off at optimum levels.

Table 3.11: Table: Power Reduction through Pressure Reduction

Pressure Reduction		Power Reduction (%)		
From(bar)	To (bar)	Single-stage Water-cooled	Two-stage Water-cooled	Two-stage Air-cooled
6.8	6.1	4	4	2.6
6.8	5.5	9	11	6.5

A reduction in the delivery pressure of a compressor would reduce the power consumption. This has been practically achieved, as discussed in the relevant case study.

- **Compressor modulation by Optimum Pressure Settings**

Very often in an industry, different types, capacities and makes of compressors are connected to a common distribution network. In such situations, proper selection of a right combination of compressors and optimal modulation of different compressors can conserve energy. Where more than one compressor feeds a common header, compressors have to be operated in such a way that the cost of compressed air generation is minimal.

If all compressors are similar, the pressure setting can be adjusted such that only one compressor handles the load variation, whereas the others operate more or less at full load.

If compressors are of different sizes, the pressure switch should be set such that only the smallest compressor is allowed to modulate. If different types are operated together, for example, both reciprocating and screw compressors, the reciprocating compressor must be allowed to modulate, while keeping the screw compressor at full load always as its part load operation consumes more power. In general, the compressor with lower no-load power consumption must be modulated. Compressors can be graded according to their specific energy consumption, at different pressures and energy efficient ones must be made to meet most of the demand.

Table 3.12: Expected Specific Power Consumption of Reciprocating Compressors (based on motor input)

Pressure bar	No. of Stages	Specific Power kW/170 CMH
1	1	6.29
2	1	9.64
3	1	13.04
4	2	14.57

7	2	18.34
8	2	19.16
10	2	21.74
15	2	26.22

- **Mains air pressure reduction**

It is often necessary to reduce the mains pressure when supply groups of plants or complete workshops. This requires a pressure reducing valve of large capacity and good flow characteristics. In these circumstances, a pressure reducing station may be used.

If the low pressure air requirement is considerable, it is advisable to generate low pressure and high pressure air separately, and feed to the respective sections instead of reducing the pressure through pressure reducing valves, which invariably waste energy.

- **Minimum pressure drop in air lines**

The air mains and their associated branches, hoses, couplings and other accessories offer considerable opportunities for energy conservation.

Table 3.13: Energy Wastage due to Smaller Pipe Diameter

Pipe Nominal Bore (mm)	Pressure drop (bar) per 100meters	Equivalent power losses (kW)
40	1.80	9.5
50	0.65	3.4
65	0.22	1.2
80	0.04	0.2
100	0.02	0.1

Excess pressure drop due to inadequate pipe sizing, choked filter elements, improperly sized couplings and hoses represent energy wastage. The above table illustrates the energy wastage, if the pipes are of smaller diameter.

- **Equivalent lengths of fittings**

When long runs of distribution mains are involved, the pressure drops maybe higher than acceptable levels; in such cases it is desirable to check for actual pressure drops.

Table 3.14: Resistance of Pipe Fittings in Equivalent Lengths (in metres)

Type of Fitting	Nominal Pipe Size in mm									
	15	20	25	32	40	50	65	80	100	125
Gate Valve	0.11	0.14	0.18	0.27	0.32	0.40	0.49	0.64	0.91	1.20
Runof standard	0.12	0.18	0.24	0.38	0.40	0.52	0.67	0.85	1.20	1.52
Tee 900long bend	0.15	0.18	0.24	0.38	0.46	0.61	0.76	0.91	1.20	1.52
Elbow	0.26	0.37	0.49	0.67	0.76	1.07	1.37	1.83	2.44	3.20
Return bend	0.46	0.61	0.76	1.07	1.20	1.68	1.98	2.60	3.66	4.88
Through side	0.52	0.70	0.91	1.37	1.58	2.14	2.74	3.66	4.88	6.40
Outlet of tee globe valve	0.76	1.07	1.37	1.98	2.44	3.36	3.96	5.18	7.32	9.45

3.8.9 Blowers in place of Compressed Air System

Since the compressed air system is already available, facilities engineers may be tempted to use compressed air to provide air for low pressure requirements such as agitating plating tanks or pneumatic conveying. Using a blower that is designed for lower pressure operation will cost only a fraction of compressed air generation cost.

3.8.10 Capacity Control of Compressors

In many installations, the use of air is intermittent. Therefore, some means of controlling the output of the compressor is necessary. This is achieved by regulation of pressure, volume, temperature or some other factors. The type of capacity control employed has a direct impact on the compressor power consumption. Some control schemes commonly used are discussed below:

- **On / Off Control**

Automatic start and stop control, as its name implies, starts or stops the compressor by means of a pressure activated switch as the air demand varies. This is a very efficient method in controlling the capacity of compressor, where the motor idle-running losses are eliminated, as it completely switches off the motor when the set pressure is reached. This is suitable for small compressors (less than 10 kW).

- **Load and Unload**

This is a two-step control where compressor is loaded when there is air demand

and unloaded when there is no air demand. During unload, the reciprocating compressor motor runs without air compression, thereby consuming only 20-30% of the full load power. In screw compressors, the unloading is achieved by closing the inlet valve. The idling power is about 40 to 50 % of the full load power depending configuration, operation and maintenance practices. While in screw compressors, the unload power consumption is marginally higher compared to reciprocating machines.

- **Multi-step Control**

Motor-driven reciprocating compressors above 75 kW are usually equipped with a multi-step control. In this type of control, unloading is accomplished in a series of steps, varying from full load down to no-load. A relevant case study has been appended for this opportunity.

Table 3.15: Power Consumption of Reciprocating Compressor at Various Loads

Load %	Power Consumption as % of full load Power
100	100
75	76-77
50	52-53
25	27-29
0	10-12

Five-step control (0%, 25%, 50%, 75% & 100%) is accomplished by means of clearance pockets. In some cases, a movable cylinder head is provided for variable clearance in the cylinder.

- **Throttling Control**

This kind of control is achieved using an inlet valve or a variable-displacement slide valve and is suitable for screw compressors where the capacity can be varied from 40 to 100%. The variable displacement method reduces the volume of air delivered by venting air from a variable portion of the helical screw length to the inlet side of the compressor. The variable displacement method is more efficient than the inlet valve.

The output of centrifugal compressors can be controlled using variable inlet guide vanes to throttle discharge pressure. However, another efficient way to match compress or output to meet varying load requirements is by speed control.

Table 3.16: Typical part load gas compression: Power input for speed and vane control of centrifugal compressors

System Volume	Flow % Speed Control	Power Input (%) Vane

111	120	-
100	100	100
80	76	81
60	59	64
40	55	50
20	51	46
0	47	43

At low volumetric flow (below 40 %), vane control may result in lower power input compared to speed control due to low efficiency of the speed control system. For loads more than 40%, speed control is recommended.

3.8.11 Avoiding Misuse of Compressed Air

Misuse of compressed air for purposes like body cleaning, liquid agitation, floor cleaning, drying, equipment cooling and other similar uses must be discouraged. Wherever possible, low-pressure air from a blower should be substituted from compressed air, for example secondary air for combustion in a boiler / furnace.

The following illustrations gives an idea of savings by stopping use of compressed air by choosing alternative methods to perform the same task.

- Electric motors can serve more efficiently than air-driven rotary devices. The following table gives the comparison of pneumatic grinders and electrical grinders. Refertable 3.17 below:

-

Table 3.17: Power Requirements for Pneumatic and Electrical Tools

Tool	Wheel dia mm	Speed rpm	Air Cons. CMH	Power kW
Pneumatic angle grinder	150	6000	102 CMH at 6bar	10.2
Electric angle grinder	150	5700-8600	N.A.	1.95 –2.90
Pneumatic jet grinder	35	30000	32.3 CMH at 6bar	3.59
Electric straight grinder	25	22900-30500	N.A.	0.18

It may be noted that in some area s use of electric tools are not permitted due to

safety constraints, especially places where inflammable vapours are present in the environment. In those cases, possibility of shifting the machine tool operation to outside the flammable area may be considered when evaluating use of electric tools. It should always be remembered that safety consideration always overrides energy conservation.

- In place of pneumatic hoists, electric hoists can be used. A comparison is given below:

Table 3.18: Comparison of Power Consumption of Pneumatic and Electric Hoists

Capacity	Type	Compressed Air Required CMH	Equivalent Power Consumption at the Compressor, kW	Motor Rating of an Electric Hoist, kW
0.5	Chain	125	12	0.37
1.0	Chain	118	12	0.37
1.5	Chain	118	12	1.125
2	Chain	118	12	1.5
5	Wire rope	200	20.25	2.7

- Material conveying applications can be replaced by blower systems of preferably by a combination of belt/ screw conveyers and bucket elevators. In a paper manufacturing facility, compressed air was used for conveying wood chips.
- For applications like blowing of components, use of compressed air amplifiers, blowers or gravity-based systems may be possible. Brushes can sweep away debris from work in progress as effectively as high-pressure air. Blowers also can be used for this purpose. When moving air really is required for an application, often sources other than compressed air can do the job. Many applications do not require clean, dry, high-pressure and expensive 6 bar or 7 bar compressed air rather, only moving air is needed to blow away debris, provide cooling, or other functions. In these cases, local air fans or blowers may satisfy the need for moving air much economically.
- Use of compressed air for cleaning should be discouraged; use of vacuum cleaners is an alternative for some applications. If absolutely necessary, compressed air should be used only with blow guns to keep the air pressure below 2 bar; higher pressure are not permitted as per national safety regulations. Use of compressed air amplifiers can also be considered for some

cleaning applications

- For applications where compressed air is indispensable for cleaning internal crevices of machines etc., installation of a separate cleaning air header with a main isolation valve may be considered. The main valve should be opened only for a few, well-defined time periods during the whole day, no connections for cleaning should be provided from process or equipment air lines.
- Replacement of pneumatically operated air cylinders by hydraulic power packs can be considered.
- Use of compressed air for personal comfort cooling can cause grievous injuries and is extremely wasteful; it should be banned from the safety viewpoint alone. Use of man coolers or air washers (in dry areas) may be encouraged. If a 1¼" hosepipe is kept open at a 7 bar compressed air line for personal cooling for at least 1000 hours/ annum, it can cost about 1,00,000 BDT/ annum.
- Vacuum systems are much more efficient than expensive venturi methods, which use expensive compressed air rushing past an orifice to create a vacuum.
- Mechanical stirrers, conveyers, and low-pressure air many mix materials far more economically than high-pressure compressed air.

3.8.12 Avoiding Air Leaks and Energy Wastage

The major opportunity to save energy is in the prevention of leaks in the compressed air system. Leaks frequently occur at air receivers, relief valves, pipe and hose joints, shutoff valves, quick release couplings, tools and equipment. In most cases, they are due to poor maintenance and sometimes, improper installation in underground lines.

Air leakages through Different Size Orifices

The following table gives the amount of free air wasted for different nozzle sizes and pressure:

Table 3.19: Discharge of Air through Orifice (Cd =1.0)

Gauge Pressure Bar	0.5mm	1mm	2mm	3mm	5mm	10mm	12.5mm
0.5	0.06	0.22	0.92	2.1	5.7	22.8	35.5
1.0	0.08	0.33	1.33	3.0	8.4	33.6	52.5
2.5	0.14	0.58	2.33	5.5	14.6	58.6	91.4
5.0	0.25	0.97	3.92	8.8	24.4	97.5	152.0
7.0	0.33	1.31	5.19	11.6	32.5	129.0	202.0

Cost of Compressed Air Leakage

It may be seen from the following table that any expenditure on sealing leaks would

be paid back through energy saving.

Table 3.20: Cost of Air Leakage

Orifice Size mm	KW Wasted	* Energy Waste (BDT/Year)
0.8	0.2	8000
1.6	0.8	32000
3.1	3.0	120000
6.4	12.0	480000

* based on BDT 5 / kWh; 8000 operating hours; air at 7.0bar

Steps in simple shop-floor method for leak quantification

- Shut off compressed air operated equipment (or conduct test when no equipment is using compressed air).
- Run the compressor to charge the system to set pressure of operation
- Note the sub-sequent time taken for 'on load' and 'off load' cycles of the compressors. For accuracy, take ON & OFF times for 8 – 10 cycles continuously. Then calculate total 'ON' Time (T) and Total 'OFF' time(t).
- The system leakage is calculated as

$$\text{System leakage (cmm)} = Q \times T / (T + t)$$

Q = Actual free air being supplied during trial, in cubic meters per minute

T = Time on load in minutes

t = Time unload in minutes

ILLUSTRATION - 1:

In the leakage test in a textile industry, following results were observed Compressor capacity (CMM) =35

Cut in pressure kg/SQCMG =6.8

Cut out pressure kg/SQCMG =7.5

On load kW drawn = 188 kW

Unload kW drawn = 54 kW Average 'On-load' time = 1.5 minutes Average 'Unload' time = 10.5minutes

Comment on leakage quantity and avoidable loss of power due to air leakages.

a) Leakage quantity (CMM)

$$\frac{(1.5) \times 35}{(1.5) + (10.5)}$$

$$= 4.375\text{CMM}$$

b) Leakage per day

$$= 6300\text{CM/day}$$

c) Specific power for compressed air generation

$$\frac{188 \text{ kWh}}{(35 \times 60)\text{CMH}}$$

$$= 0.0895 \text{ kWh/m}^3$$

d) Power lost due to leakages/day = 563.85 kWh

- **Leakage Test by Ultrasonic Leak Detector**

Leakage tests are conducted by a Leak Detector having a sensing probe, which senses when there are leakages. The leak is detected by ultrasonic vibration. Leak testing is done by observing and locating sources of ultrasonic vibrations created by turbulent flow of gases passing through leaks in pressurized or evacuated systems. Use is made of ultrasonic detector to detect air borne and structure-borne vibrations, and translators that convert these into audible high frequency sounds to lower frequencies within the range of human hearing. Detection of leaks in compressed air and gas systems at high temperatures, beneath insulated coverings, and in pipelines and manifolds, can be done.

Leak detection and location from a distance through air or other fluids involves remote scanning of suspected leak areas with a directional probe and coordinating the direction of the source of the characteristic hissing sound of the leak with the relative sound intensity. Probably the greatest advantage of ultrasonic leak detection is that this method can be used with any fluid (liquid, gas or vapour) if the physical conditions for sound generation are met in the leak. When leak conditions generate sound in ambient air, leaks can be detected up to and beyond 30 metres (100 feet). This offers advantages when extended structures are to be inspected. Ultrasonic mechanical vibration signal energy, is converted to electrical signal energy by an appropriate transducer. The single most significant factor to be noted is the frequency distribution of ultrasonic energy from leaks. All leaks possess energy in the 30/50 kHz. At lower pressure of 480 and 70 kPa (70 and 10 psi), it is seen that there is a distinct maximum around 40 kHz.

3.8.13 Compressor Capacity Assessment

- **Need for Capacity Assessment**

The compressor capacity is expressed in terms of quantity of free air delivered at a particular pressure. Due to ageing of the compressors and inherent inefficiencies in the internal components, the free air delivered may be less than the design value, despite adherence to good maintenance practices. Sometimes, other factors such as poor maintenance, fouled heat exchanger and effects of altitude also tend to reduce free air delivery. In order to meet the air demand, the inefficient compressor may have to run for more time, thus consuming more power than actually required.

The power wastage depends on the percentage deviation of FAD capacity. For example, a worn out compressor valve can reduce the compressor capacity by as much as 20 percent. A periodic assessment of the FAD capacity of each compressor has to be carried out to check its actual capacity. If the deviations are more than 10%, corrective measures should be taken to rectify the same.

The ideal method of compressor capacity assessment is through a nozzle test where in a calibrated nozzle is used as a load, to vent out the generated compressed air. Flow is assessed, based on the air temperature, stabilization pressure, orifice constant etc.

Simple method of Capacity Assessment in Shop-floor

- Isolate the compressor along with its individual
- Receiver being taken for test from main compressed air system by tightly closing the isolation valve or blank, thus closing the receiver outlet.
- Open water drain valve and drain out water fully and empty the receiver and the pipe line. Make sure that water trap is tightly closed once again to start the test.
- Start the compressor and activate the stop watch.
- Note the time taken to attain the normal operational pressure P_2 (in the receiver) from initial pressure P_1 .
- Calculate the capacity as per the formulae given below:

Actual Free air discharge

$$Q = \frac{P_2 - P_1}{P_0} \times \frac{V}{T} N \frac{M^3}{Min}$$

P_2 = Final pressure after filling ($\text{kg/cm}^2 \text{ a}$)

P_1 = Initial pressure ($\text{kg/cm}^2 \text{ a}$) after bleeding

P_0 = Atmospheric Pressure ($\text{kg/cm}^2 \text{ a}$)

V = Storage volume in m^3 which includes receiver, after cooler, and delivery piping

T = Time take to build up pressure to P_2 in minutes

ILLUSTRATION - 2:

An instrument air compressor capacity test gave the following results – Comment?

Make: ABC

Date:

Time:

Test No.:1

Piston displacement: 16.88 CMM

Theoretical compressor capacity: 14.75 CMM @ 7 kg/SQCMG

Compressor rated rpm 750: Motor rated rpm1445

Receiver Volume: 7.79 CM

Additional hold up volume,

i.e., pipe / water cooler, etc., is: 0.4974 CM Total volume: 8.322CM

Initial pressure P_1 : 0.5 Kgf /SQCMG

Final pressure P_2 : 7.03 Kgf / SQCMG

Pump up time: 4.021-----

Atmospheric pressure P_0 : 1.026Kgf/cm²_a

$$\text{Compressor output CMM} = \frac{(P_2 - P_1) * \text{Total Volume}}{\text{Atm. Pressure} * \text{Pumpup time}}$$

$$\frac{(7.03 - 0.5) * 8.322}{1.026 * 4.021} = 13.17 \text{ CMM}$$

Comment:

Capacity shortfall w.r.t. 14.75 CMM rating is 1.577 CMM i.e., 10.69% Compressor performance needs to be investigated further.

ILLUSTRATION - 3:

Assessing compressed air system study for a plant section gave following results.

Compressors on line A, B, C, D, E

- All reciprocating type
- Trial observation Summary

Compressor Reference	Measured Capacity CMM (@ 7 kgf/ SQCMG)	'On' Load kW	'Unload' kW	Load Time Min.	Unload Time Min.
A B C D E	13.17	115.30	42.3	Full time*	0
	12.32	117.20	51.8	Full time*	0
	13.14	108.30	43.3	Full time*	0
	12.75	104.30	29.8	Full time*	0
	13.65	109.30	39.3	5.88	39.12

*Compressors running in load conditions and not getting unloaded during normal operations

Comments:

- **For a cycle time of 45 minutes (39.12 + 5.88)**

- Compressed air generated in M³*
 $45 (13.17) + 45 (12.32) + 45 (13.14) + 45 (12.75) + 5.88 (13.65) = 2392.36$
 - Power consumption kWh*
 $45/60 (115.3) + 45/60 (117.20) + 45 / 60 (108.3) + 45/60 (104.3) + 5.88/60 (109.8) + ((39.12) / 60) 39.3 = 370.21 \text{ kWh}$
 - Compressed air generation capacity on line in M³*
 $45 [13.17 + 12.32 + 13.14 + 12.75 + 13.65] = 2926.35 \text{ M}^3$
- The consumption rate of the section connected*
 $2392.36 / 45 \text{ CMM} = 53.16 \text{ CMM}$
 - Compressor air draw as a % of capacity on line is $[2392.36 / 2926.35] \times 100 = 81.75\%$*
 - Specific power consumption = $370.21 \text{ kWh} / 2392.36 = 0.155$*
 - Idle power consumption due to unload operation = 25.62 kWh every 45 minutes cycle i.e., 34.16 kWh every hour.*
 - It would be favorable and energy efficient to keep the compressor 'D' in cycling mode on account of lower un-load losses.*
 - A suitable smaller capacity compressor can be planned to replace the compressor with highest unload losses.*
 - An investigation is called for, as to why such a large variation of unload power drawn, exists although all compressors have almost the same rated capacity.*

3.8.14 Line Moisture Separator and Traps

Although, in an ideal system, all cooling and condensing of air should be carried out before the air leaves the receiver, this is not very often achieved in practice. The amount of condensation, which takes place in the lines, depends on the efficiency of moisture extraction before the air leaves the receiver and the temperature in the mains itself. In general, the air main should be given a fall of not less than 1 min 100 min the direction of air flow, and the distance between drainage points should not exceed 30m.

Drainage points should be provided using equal tees, as it assists in the separation for water. Whenever a branch line is taken off from the main it should leave at the top so that any water in the main does not fall straight in to the plant equipment. Further, the bottom of the falling pipe should also be drained.

3.8.15 Compressed Air Filter

Although some water, oil and dirt are removed by the separators and traps in the mains, still some of it is always left, which is being carried over. Moreover, pipe systems accumulate scale and other foreign matters, such as small pieces of gasket

material, jointing compounds and soon. Burnt compressor oil may also be carried over in pipe work, and this, with other contaminants, forms a gummy substance. To remove these, all of which are liable to have deleterious effects on pneumatic equipment, the air should be filtered as near as possible to the point of use. Water and oil collected in the filter sump must be drained off because, if its level is allowed to build up, then it is forced through the filter element in to the very system it is designed to protect.

3.8.16 Regulators

In many instances, pneumatic operations are to be carried out at a lower pressure than that of the main supply. For these applications, pressure regulators are required to reduce the pressure to the required value and also to ensure that it remains reasonably constant at the usage point. Pilot operated type regulators are energy efficient than direct-acting and self-relieving regulators. In the self-relieving type, a small relief valve is provided which allows excess air to bleed away, should the downstream pressure exceed the set value. It is suitable for applications where the control pressure has to be varied periodically.

3.8.17 Lubricators

Where air is used to drive prime movers, cylinders and valves, they should be fitted with a lubricator. Essentially, a lubricator is a reservoir of oil and has been designed so that when air is flowing, metered amount of oil is fed in mist form into the air stream. This oil is carried with the motive air, to the point of use to lubricate all moving parts. All lubricators require a certain minimum rate of air flow to induce oil into their stream. Their design should be such that once the air flow is more than this minimum rate, they give as is factory lubrication without causing an excessive pressure drop. Light free-fogging, lubricating oil with a high velocity index and without lead additives is suitable for lubrication. The ratio of oil to air can be decided experimentally. A rough guide is, one drop of oil per minute for every $5\text{dm}^3/\text{s}$ of free air at 5.5 bar pressure.

It is advisable to fix filters, regulators and lubricators as close as possible to the equipment being served. Where lubricators are used to provide oil for linear actuators or when the direction of air flow is reversed, the volume of pipe work between the lubricator and cylinder should not exceed to 50 % of the volume of free air used by the cylinder per stroke.

3.8.18 Air Dryers

There are certain applications where air must be free from moisture and have a lower dew point. This calls for more sophisticated and expensive methods to lower the dew point of compressed air. Three commonly used types of air dryers are heat-

less (absorption), absorption and chiller dryers. They produce dry air with 10°C – 40°C dew point, depending on the type of dryers.

Table 3.21: Moisture Content in Air

Dew point at Atmospheric Pressure $^{\circ}\text{C}$	Moisture Content, ppm
0	3800
-5	2500
-10	1600
-20	685
-30	234
-40	80
-60	6.5

Table 3.22: Pressure Dew Point and Power Consumption Data for Dryers

Type of Dryer	Atmospheric Dew Point $^{\circ}\text{C}$	First Cost	Operating Cost	Power Cons. For $1000\text{m}^3/\text{hr}$
Refrigeration	-20	Low	Low	2.9 kW
Desiccant regenerative (by compressed air purging)	-20	Low	High	20.7 kW
Desiccant regenerative (external or internal heating with electrical or steam heater, reduced or no compressed air purging)	-40	Medium	Medium	18.0 kW
Desiccant regenerative (using heated low pressure air, no compressed air loss)	-40	High	Low	12.0 kW
Desiccant regenerative (by recovery of heat of Compression from compressed air)	-40	High	Very low	0.8 kW

3.8.19 Air Receivers

The main purpose of a receiver is to act as a pulsation damper, allowing intermittent demands for compressed air to be met from a small compressor set, resulting in lesser energy consumption.

If receiver is sized too small for air demand, compressor will run for longer periods. By improving the ability of storage to meet air demand, running time of the compressor is minimised, thereby reducing energy usage as well as wear and tear. Compressed air systems usually have one primary receiver and possibly few secondary receivers near high intermittent air using equipment.

The air receiver should be generously sized to give a large cooling surface and even out the pulsation in delivered air pressure from a reciprocating compressor. As per IS 7938-1976, volume of air in receiver (in m³) should be 1/10th to 1/6th of the output in m³/min.

A simple formulae often quoted for air receiver size is to take a value equal to one minute's continuous output of the compressor. However, this should be considered indicative of the minimum size of receiver. A better suggestion is to estimate the peak air consumption likely and allow for the maximum pressure drop that is acceptable at this peak load.

$$\text{Receiver capacity in m}^3 = \frac{\text{m}^3 \text{ of free air volume required}}{\text{permissible pressure drop in bar}}$$

If peaks cannot be quantified, another approximation can be to size the receiver volume to be 5% of the rated hourly free air output. Providing an air receiver at the load end, where there is sudden high demand lasting for a short period, would avoid the need to provide extra capacity.

3.8.20 Capacity Utilisation

In many installations, the use of air is intermittent. This means the compressor will be operated on low load or no load condition, which increases the specific power consumption per unit of air generated. Hence, for optimum energy consumption, a proper compressor capacity control should be selected. The nature of the control device depends on the function to be regulated. Regulation of pressure, volume, temperature or some of the factors determines the type of regulation required and the type of the compressor drive.

Module 4

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Note: The data given in examples are for illustrative purposes only and does not reflect actual prices or savings.

1. Financial Management

1.1. Introduction

Businesses are increasingly realizing that prices of energy like coal, oil and natural gas are going to be expensive and there is a need to reduce energy use. Energy savings can be achieved by

- improving organizational procedures,
- adopting best operation and maintenance (O & M) practices, and/or
- modifying or replacing existing equipment with energy efficient equipment.

In the process of implementing energy saving measures once the best operation and maintenance practice options are exhausted investment would be required for implementing the other options for modifications/retrofitting and for incorporating new technology to further reduce the energy consumption. The investment requirements for different options need to be prioritized to derive maximum benefit at least cost. The investment criteria is also governed by the level of investments required, funding options available, ease of obtaining finance, demand for their products (increasing/decreasing/static), interest & currency rate scenarios, taxation, cost of production etc.

An understanding and appreciation of project cash flows and systematic approaches to prioritize and rate the different investment options vis-à-vis the anticipated savings is essential to

- identify the benefits of the proposed measure with reference to energy savings
- identify other associated benefits such as increased productivity, improved product quality etc.

The financial approach will help energy specialist to push the business case of energy project, which is energy conservation is aligned with making money and profits.

The aim of this module is to provide understanding of

- Investment need and appraisal criteria.
- Financial analysis approach and techniques.
- Time and money relationship.
- Financial analysis techniques that apply to recurring costs and savings.
- Taxes and their effect on costs and savings.
- Rate of depreciation and its impact on investment.
- The process of borrowing money to finance an energy project and impact of costs by borrowing from different sources.

- Using excel tools for conducting financial analysis.

1.2. Investment Need and Appraisal Criteria

To consider investment in energy efficiency an organization need to be convinced that the energy project is profitable and comparable to other profit enhancement projects like increasing production. An investment proposal highlighting the following aspects should be presented to the management for active consideration of energy projects.

- The size of the energy problem it currently faces (eg. Cost of energy in terms of overall production costs, regulatory requirements etc.)
- Best operational and maintenance practices (technical and good housekeeping measures) available to reduce energy use or improve energy efficiency at low costs (Eg. by providing appropriate training to employees).
- Proven and implemented energy saving projects that are technically and economically feasible.
- Incentives (lower tax rates, accelerated depreciation allowance, subsidies, insurance against failure, soft loans) available that make the project financially viable.
- Add on benefits from the energy project in terms of faster production, improved product quality, safety, human comfort in quantitative terms to the extent possible.
- The predicted return on investment.

The need for investments in energy conservation can arise under following circumstances

- Toretrofit existing technology& equipment and with new energy efficient one owing to
 - normal replacement of equipment at end of life or
 - due to substantial savings foreseen by replacing existing equipment,
- To modify or improve existing process by new technology owing to regulations or substantial savings foreseen.
- To provide staff training
- To implement or upgrade the energy information system

1.2.1 Criteria

Any investment has to be seen as an addition and not as a substitute for having effective management practices for controlling energy consumption throughout the organization. Spending money on technology or equipment for energy management cannot compensate for inadequate attention in O & M aspects to gain control over energy consumption. Therefore, before any investments are made, the first step is to

ensure that:

- Organization's maintenance policy and practices tap all energy efficiency opportunities through best operation and maintenance practices and procedures.
- Energy charges are set at the lowest possible tariffs.
- Best energy forms - fuels or electricity –is used and as efficiently as possible.

Technical Appraisal criteria

The next step is to list investment opportunities. While considering these opportunities the following criteria need to be considered:

- Current energy consumption status: Compare existing energy consumption per unit of production (specific energy consumption) of a plant or process against the best benchmark figure established by peer companies or established by R &D.
- Consider availability of know-how or equipment to achieve the benchmark.
- The current state of repair and energy efficiency of the plant/building design and services, including controls
- The quality of the indoor environment like room temperatures, indoor air quality and air change rates, drafts, glare, etc.
- The effect of any proposed measure on staff attitudes and behaviour.

This criteria helps complete technical evaluation. Once the list of investment opportunities are shortlisted based on the above criteria the investments required and savings appraisal needs to be done.

Investment Appraisal criteria

Energy manager has to

- Identify how cost savings arising from energy management contribute to profits,
- How energy projects are comparable to other profit enhancing projects and
- How energy projects are integral to manufacturing and not standalone projects.

To do this, he/she has to work out how benefits of increased energy efficiency can be best sold to top management as:

- Reducing operating /production costs
- Increasing employee comfort and well-being and thereby scope of worker productivity.

- Improving cost-effectiveness and/or profits
- Protecting under-funded coreactivities
- Enhancing the quality of service or customer care delivered.
- Protecting theenvironment

To conduct the investment appraisal it needs to be appreciated that investment in energy efficiency is no different from any other investments. So one should apply the same criteria to energy saving investments as it applies to all its other investments.

1.3. Financial Analysis Approach and Techniques

Business's prime goal is to maximize profits. So, in assessing the financial viability of any project the proposal should answer the following questions.

- How much will the proposalcost?
- How much money will be saved by theproposal?
- Whether alternate proposals cost less and save more?

It is therefore important that the financial appraisal process allows for all these factors, with the aim of determining which investments should be undertaken, and of optimizing the benefits achieved. The appraisal process involves understanding of types of costs and their impacts on the project. This appraisal process is divided into three parts.

- The first part of this analysis will cover types of costs and their impacts.
- The second part will cover techniques for appraisal of investment.
- The third part will cover sensitivity analysis to assess risks associated in financial appraisal of projects.

1.3.1 Profit, Revenue and Costs

Business's prime goal is to maximize profits which occurs when difference between total revenue and total cost is the highest.

$$\text{Profit} = \text{Total Revenue} - \text{Total Costs}$$

Energy specialists have no control on factors impacting revenue. However, energy specialists can aid in cost minimization by

- identifying and evaluating energy conservation ways in existing systems to reduce energy consumption costs
- modifying, replacing equipment or system which involve purchasing and costs money

For proposing energy saving project the energy specialist need to explain the project's net impact on cash-flows and the net savings the project will accrue. For

this an understanding of income statement and how it is prepared is essential. The following table presents a simplified structure:

$$\begin{aligned} \text{Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA)} \\ = \text{Operating Income} - \text{Operating Expenses} \end{aligned}$$

$$\begin{aligned} \text{Earnings before Interest and Taxes (EBIT)} \\ = \text{EBITDA} - \text{Amortization and depreciation expenses} \end{aligned}$$

$$\text{EBIT} = \text{Operating Revenue} - \text{Operating expenses} + \text{Non operating Income}$$

$$\text{Earnings before Taxes (EBT)} = \text{EBIT} - \text{Interest Expenses}$$

$$\text{Earnings after Taxes (EAT)} = \text{EBT} - \text{Income Tax Expenses}$$

While expenses/costs like interest, depreciation expenses, cost of energy or fuel are easy to apportion in an energy saving project, certain taxes by their income independent nature (Eg. value added tax) are neglected in financing and investment appraisals as they represent a pass-through item. However, how these taxes may affect the viability of the project needs to be appreciated by energy saving project proponents and this factor needs to be considered in sensitivity/risk analysis of the projects.

This first and second part of this module will highlight how each of these cash-flow elements effect investment choices

Example 1 : Estimating EBIT

Sales Revenue	BDT 300,000
Cost of goods sold	BDT 5,000
Depreciation	BDT 8,000
Selling expenses	BDT 2,000
Non-operating income	BDT 500

$$\text{EBIT} = 300,000 - (5,000 + 8,000 + 2,000) + 500 = \text{BDT } 240,500$$

1.3.1.1 Costs and Revenues

The costs and savings flow in any project can be classified as:

- **Fixed costs** are costs paid once like for purchasing capital equipment. Capital costs are costs associated with the design, planning, installation and commissioning of the project; and are unaffected by inflation or discount rate factors. However, instalments paid over a period of time will have time costs associated with them.
- **Variable costs** and savings are costs and savings paid on regular basis over a specified period of time. Variable costs include raw material costs, taxes,

insurance, equipment leases, energy costs, servicing, maintenance, operating labour, and so on. Variable savings are annual savings accruing from a project that occur over the life of the project. Increases in any of these costs represent negative cash flows, whereas decreases in the costs or increase in savings represent positive cash flows.

The total cost of any project is the sum of the fixed and variable costs. Example 1 illustrates how both fixed and variable costs combine to make the total operating cost.

Example 2: Understanding fixed and variable costs

The capital cost of the DG set is BDT 9,00,000, the annual output is 219 MWh, and the maintenance cost is BDT 30,000 per annum. The cost of producing each unit of electricity is 3.50 BDT/kWh. The total cost of a diesel generator operating over a 5-year period, taking into consideration both fixed and variable cost is:

Item	Type of Cost	Calculation	Cost (BDT)
Capital cost of generator	Fixed	-	9,00,000
Annual Maintenance	Fixed	30,000 x 5 (years)	1,50,000
Fuel cost	Variable	219,000 x 3.50 x 5	38,32,500
		Total Cost	48,82,500

From Example 1, it can be seen that the fixed costs represent 21.5% of the total cost. In fact, the annual electricity output of 219 MWh assumes that the plant is operating with an average output of 50 kW. If this output were increased to an average of 70 kW, then the fuel cost would become BDT 53,65,500, with the result that the fixed costs would drop to 16.37% of the total.

Thus the average unit cost of production decreases as output increases. This phenomenon is better explained using the concept of marginal analysis.

1.3.1.2 Marginal analysis

Marginal analysis is used to determine how much amount should be spent on energy saving projects and to compare energy projects that do not cost the same amount of money to implement.

Marginal refers to the last increment of a variable, like last LED bulb or solar panel installed in a building. **The criteria applied for the project is till the marginal savings exceed the marginal cost, it is economical to add another unit.** The example below illustrates the application and concept.

Example 3: Marginal Analysis and the proper amount of insulation

The marginal cost and cost savings of insulating a home with different thicknesses of insulation are as follows:

Amount of insulation (in inches)	Marginal cost(BDT)	
	per sq. ft of last inch	Savings per sq. ft of last inch
1	5.83	125.01
2	1.67	41.67
3	1.67	16.67
4	1.67	8.33
5	1.67	5.83
6	1.67	4.17
7	1.67	2.50
8	1.67	2.08
9	1.67	1.25

Find: the proper amount of insulation to install.

Solution: The proper amount is where marginal cost is equal to marginal cost savings. This occurs between the eighth and ninth inch of insulation. Therefore, if the home owner installs the eighth inch, the cost savings are greater than the costs. However, if the ninth inch is installed, the cost of that inch is greater than the cost savings it generates. Since insulation cannot be bought by the half-inch the least profitable inch to install in this case is the eighth inch. Therefore, eighth inches of insulation should be installed.

To achieve maximum accuracy marginal analysis should be applied to the smallest possible units. For example it is better to analyse solar collector by square foot that by 32 ft² collector

The concept of equating costs with savings can also be estimated using break-even analysis concept.

1.3.1.3 Break-even Analysis:

The concept of fixed and variable costs can be used to determine the break-even point for a proposed project. The break-even point can be determined by using the following equation.

$$UC_{util} \times W_{av} \times n = FC + (UC_{prod} \times W_{av} \times n)$$

Where,

UC _{util}	unit cost per kWh of energy bought from utility (BDT/kWh)
UC _{prod}	unit cost per kWh of produced energy(BDT/kWh)
FC	fixed costs(BDT)
W _{av}	average power output (or consumption) (kW)
n	number of hours of operation(hours)

Example 4 : Assessing break-even point

If the electricity bought from a utility company costs an average of BDT 4.5/kWh, the breakeven point for the generator described in Example 1, when the average output is 50 kW is given by:

$$4.5 \times 50 \times n = (900000 + 150000) + (3.5 \times 50 \times n)$$
$$n = 21000 \text{ hours}$$

If the average output is 70 kW, the break-even point is given by:

$$4.5 \times 70 \times n = (9,00,000 + 1,50,000) + (3.50 \times 70 \times n)$$
$$n = 15000 \text{ hours}$$

Thus, increasing the average output of the generator significantly reduces the break-even time for the project. This is because the capital investment (i.e. the generator) is being better utilised.

Having understood the broader aspect of assessing the financial viability of the project one needs to understand different elements of the cost like interest rate, taxes etc. that affect the cash flows.

Factors that need to be considered in calculating annual cash flows are:

- Interest on loan or deposits.
- Taxes, using the marginal tax rate applied to positive or negative cash flows.
- Asset depreciation, the depreciation of plant assets over their life; depreciation is a "paper expense allocation" rather than a real cash flow, and therefore is not included directly in the life cycle cost. However, depreciation is "real expense" in terms of tax calculations, and therefore does have an impact on the tax calculation noted above. For example, if a BDT 10,00,000 asset is depreciated at 20% and the marginal tax rate is 40%, the depreciation would be BDT 200,000 and the tax cash flow would be BDT 80,000 and it is this later amount that would show up in the costing calculation.
- Intermittent cash flows occur sporadically rather than annually during the life of the project, relining a boiler once every five years would be an example.

1.4. Time Value of Money

Financial organizations like banks offer interest on money deposited and charge interest on money lent. Businesses borrow for projects if the earnings anticipated are more than the interest charged for borrowing. If businesses have enough internal resources they may invest their own funds if the interest difference between money deposited vs borrowed is high and yields net benefits. The interest charges change the value of money with time creating the problem of equating cash flows which occur at different times. To account for the time value of money and to equate cash flows it is therefore important to understand

- How interest charges are calculated.
- How to equate cash flows (single cash flow or series of uniform and non-uniform cash flows) to a common basis of time either in present or future terms (called present value or future value of money)?

1.4.1 How interest charges are calculated.

Two types of interest is normally charged namely simple interest and compound interest.

In simple interest calculation charges are calculated as a fixed percentage of the capital that is borrowed. In compound calculation interest charged is calculated on the sum of the unpaid capital and the interest charges up to that point. The equations for calculation of simple and compound interest and the concept are given in the table below.

Table: Calculation and Concept of Simple and Compound interest																																							
Simple Interest		Compound interest																																					
$Simple\ interest\ (SI) = \frac{r}{100} \times P \times n$		$Compound\ Interest\ (CI) = P \times (1 + \frac{r}{100})^n$																																					
$Total\ Repayment\ value\ based\ on\ SI\ (TRV) = \frac{P \times n \times r}{100} + P$		$Total\ Repayment\ value\ based\ on\ CI\ (TRV) = P \times (1 + \frac{r}{100})^n + P$																																					
<table border="1"> <tr> <td></td><td></td><td>$r_{3rd\ yr} = (1xr)$</td><td></td></tr> <tr> <td></td><td></td><td>$r_{2nd\ yr} = (1xr)$</td><td>$r_{1st\ yr} = (1xr)$</td></tr> <tr> <td></td><td>$= (1xr)$</td><td>$r_{1st\ yr} = (1xr)$</td><td>$r_{1st\ yr} = (1xr)$</td></tr> <tr> <td>$P = BDT\ 1$</td><td>$BDT\ 1$</td><td>$BDT\ 1$</td><td>$BDT\ 1$</td></tr> <tr> <td>$FV_{0th\ yr} = P = BDT\ 1$</td><td>$FV_{1st\ yr} = 1 + r$</td><td>$FV_{2nd\ yr} = 1 + r + r$</td><td>$FV_{3rd\ yr} = 1 + r + r + r$</td></tr> </table>				$r_{3rd\ yr} = (1xr)$				$r_{2nd\ yr} = (1xr)$	$r_{1st\ yr} = (1xr)$		$= (1xr)$	$r_{1st\ yr} = (1xr)$	$r_{1st\ yr} = (1xr)$	$P = BDT\ 1$	$BDT\ 1$	$BDT\ 1$	$BDT\ 1$	$FV_{0th\ yr} = P = BDT\ 1$	$FV_{1st\ yr} = 1 + r$	$FV_{2nd\ yr} = 1 + r + r$	$FV_{3rd\ yr} = 1 + r + r + r$	<table border="1"> <tr> <td>$P = BDT1$</td><td>$\times (1 + r)$</td><td>$\times (1+r)$</td><td>$\times (1+r)$</td></tr> <tr> <td colspan="2">Amount First Year end</td><td></td><td></td></tr> <tr> <td colspan="2">Amount Second year end</td><td></td><td></td></tr> <tr> <td colspan="2">Amount Third year end</td><td></td><td></td></tr> </table>		$P = BDT1$	$\times (1 + r)$	$\times (1+r)$	$\times (1+r)$	Amount First Year end				Amount Second year end				Amount Third year end			
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$P = BDT\ 1$	$BDT\ 1$	$BDT\ 1$	$BDT\ 1$																																				
$FV_{0th\ yr} = P = BDT\ 1$	$FV_{1st\ yr} = 1 + r$	$FV_{2nd\ yr} = 1 + r + r$	$FV_{3rd\ yr} = 1 + r + r + r$																																				
$P = BDT1$	$\times (1 + r)$	$\times (1+r)$	$\times (1+r)$																																				
Amount First Year end																																							
Amount Second year end																																							
Amount Third year end																																							
Where P Principal value r interest rate (%)		n repayment period(years) SI Simple interest CI Compound Interest TRV total repayment value which represents the future value of principal borrowed																																					

The techniques involved in calculating simple and compound interest are illustrated in Example 5.

Example 5 : Calculating Simple and Compound Interest

A company borrows BDT 3,00,00,00 to finance a new boiler installation. If the interest rate is 10% per annum and the repayment period is 5 years. Calculate the value of the total repayment and the monthly repayment value, assuming (i) simple interest and (ii)



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compound interest.

(i) Assuming simple interest:

$$\text{Total repayment} = 30,00,000 + (10/100 \times 30,00,000 \times 5) = \text{BDT } 45,00,000$$

$$\text{Monthly repayment} = 45,00,000 / (5 \times 12) = \text{BDT } 75,000$$

(ii) Assuming compound interest

$$\begin{aligned} \text{Repayment at end of year 1} &= 30,00,000 + (10/100 \times 30,00,000) \\ &= \text{BDT } 33,00,000 \end{aligned}$$

$$\begin{aligned} \text{Repayment at end of year 2} &= 33,00,000 + (10/100 \times 33,00,000) \\ &= \text{BDT } 36,30,000 \end{aligned}$$

Similarly, the repayments at the end of years 3, 4 and 5 can be calculated:

$$\text{Repayment at end of year 3} = \text{BDT } 39,93,000$$

$$\text{Repayment at end of year 4} = \text{BDT } 43,92,300$$

$$\text{Repayment at end of year 5} = \text{BDT } 48,31,530$$

Alternatively, the following equation can be used to determine the compound interest repayment value.

$$\text{Total repayment value} = 30,00,000 \times (1 + 10 / 100)^5 = \text{BDT } 48,31,530$$

$$\text{Monthly repayment} = 4831530 / (5 \times 12) = \text{BDT } 80,525$$

It can be seen that by using compound interest, the lender recoups an additional BDT 31,530. Lenders usually charge compound interest on loans.

1.4.2 How to equate cash flows?

The method by which various cash flows are related is called **future**, or the **present value concept**.

For example, if money can be deposited in the bank at 10% interest, then a BDT 100 deposit will be worth BDT 110 in one year's time. Thus the BDT 110 in one year is a future value equivalent to the BDT 100 present value.

In the same manner, BDT 100 received one year from now is only worth BDT 90.91 in today's money (i.e. BDT 90.91 plus 10% interest equals BDT 100). Thus BDT 90.91 represents the present value of BDT 100 cash flow occurring one year in the future. If the interest rate were something different than 10%, then the equivalent

present value would also change.

The relationship between present and future value is determined as follows:

$$\text{Future Value} = NPV (1 + i)^n$$

$$NPV = \frac{FV}{(1 + i)^n}$$

Where

FV = Future value of the cash flow

NPV = Net Present Value of the cash flow

i = Interest or discount rate

n = Number of years in the future

Also, the present and future value can be determined using the Present Value Interest Factor (PVIF) and Future Value Interest Factor (FVIF) using Appendix 1 and 2.

$$FV_n(BDT\ 1) = PV \times FVIF (n\ years, r)$$

$$PV_n(F) = F \times PVIF (n\ years, r)$$

Example 6: Future Value of a Fixed Amount Greater than BDT1.

A house decides to buy two 1 m² solar collector panels at BDT20000 each and has the option of paying BDT 20000 now or BDT 30000 5 years from now. The relevant interest rate is 10%.

Let us find the payment plan that will minimize the cost the house owner must pay using future value method. The future value is calculated using any of the three methods given below.

Solution:

The future value of BDT 20000, 5 years from now, is calculated as follows

Method 1: using the formula *Future Value* = *NPV* (1 + *i*)^{*n*}

$$FV = 20000(1+0.1)^5 = \text{BDT } 32210$$

Method 2: using FVIF tables (Appendix 2 given at the back of this module).

$$\begin{aligned} FV_5(\text{BDT } 2000) &= 20000 \times FVIF (5\ years, 10\%) \\ &= 20000 \times 1.6105 \end{aligned}$$

= BDT 32210

Method 3: using MS Excel.

MS Excel Formula = FV(rate, no. of periods, principal ,1)

C4	:	X	✓	fx	=FV(C3,C2,,C1,1)
	A	B	C		
1	Principal	BDT		20000	
2	No. of years	years		5	
3	Rate of interest	%		10%	
4	FV(25000)	BDT		32210	

FVIF (5 years, 10%) is obtained from Appendix 2. Thus, the future value of the BDT 30000 payment in 5 years is less than the BDT 20000 payment now, and the business could wait 5 years and pay BDT 30000 to minimise the cost. Instead of paying BDT2000 now, the business could put the BDT20000 in a bank account drawing 10% interest per year. After 5 years, the business would have BDT32210 in the account and could pay the BDT30000 and use the remaining BDT2210 for something else. If the BDT20000 is paid now, the business in effect loses BDT2210.

1.4.2.1 Cost Escalation

The price of various goods and services increases with time. To estimate the cost escalation, future value can be usefully applied. An example is illustrated below.

Example 7: Escalation of energy cost

The price of the natural gas is BDT 290 per Million Metric BTUas on May 2018. Let us consider this will increase 12% per year for the next 10 years. Estimate the price of natural gas after 1st, 6th and 10th years

Solution:

Method 1: using the formula $Future\ Value = NPV (1 + i)^n$

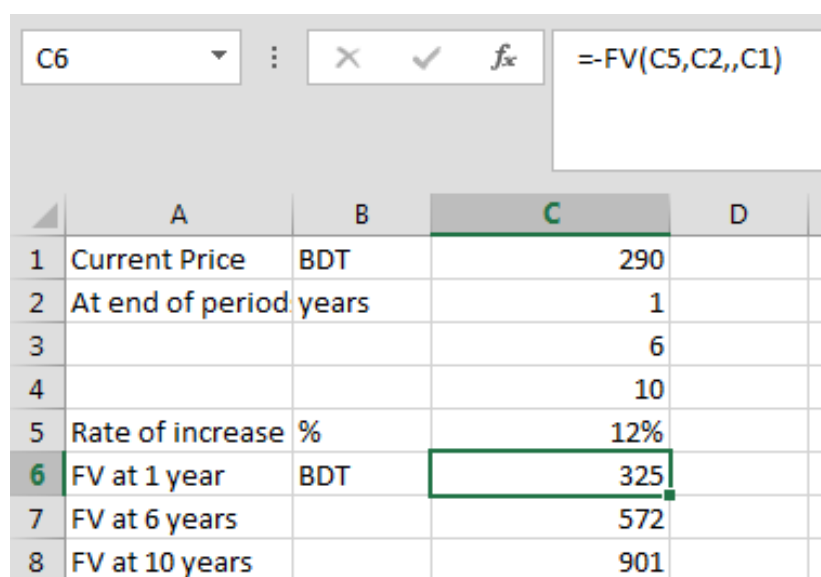
FV of NG at end of	BDT
1 year	325
6 years	572
10 years	901

Method 2: Using Formula: Price of natural gas after n years = Price now x FVIF(n year, 12%)

Solution:

Price of natural gas after 1 year	= BDT 290 x 1.1200 = BDT 325
Price of natural gas after 6 years	= BDT 290 x 1.9738 = BDT 572
Price of natural gas after 10 years	= BDT 290 x 3.1058 = BDT 901

Method 3: Using MS Excel Formula: FV(rate, no. of periods, principal ,1)



The screenshot shows an Excel spreadsheet with the following data:

	A	B	C	D
1	Current Price	BDT	290	
2	At end of period	years	1	
3			6	
4			10	
5	Rate of increase	%	12%	
6	FV at 1 year	BDT	325	
7	FV at 6 years		572	
8	FV at 10 years		901	

The formula bar shows: `=FV(C5,C2,,C1)`

1.4.2.2 Annuity

Most projects yield series of cost savings contrary to one-time amount as per the present/future value equation. These series of cash-flows are to be standardized, because savings occur at different times. The standardization can be done by assessing the present/future value of these flow of savings. This method of standardization of series of cash flows is called annuity. Annuity is a pattern of uniform/equal cash flow that is received or spent each year.

The present/future value of annuity can be calculated using the following formulas.

$$FVA_n(BDT\ 1) = (1 + r)^{n-1} + (1 + r)^{n-2} + \dots + (1 + r)^1 + BDT1$$

Where,

$FVA_n(BDT\ 1)$ = Future value of an annuity of BDT 1 after paying for n time periods at 'r' rate of interest.

$$FVA_n(M) = M \times FVIF_a(n\text{years}, r)$$

Where,

$FVA_n(M)$ = Future value (sum) of an annuity of M after paying for n time periods at ' r ' rate of interest.

M = Amount of the annuity

$FVIF_a(n\text{ years}, r)$ = Future value of an annuity of BDT 1, after paying for n time periods at ' r ' rate of interest. (This can be obtained from Appendix 4)

n = Number of years the annuity is received

Example 8: Sum of an annuity of more than BDT 1 per year

An intermediate raw material store room in a factory building is equipped with 300 watts (W) of fluorescent lighting, although only 30W are needed. The lights burn 24 hours per day (24 h/d), 365 days per year (d/yr).

Find: the cost savings per year resulting from the reduction in watts in the store room and the future value of these cost savings after 4 years if cost of electricity is BDT 5 per kilowatt hour (kWh), and the interest rate is 8%.

Method 1: Using formula

$$FVA_n(BDT\ 1) = 11826 \times \{ (1 + 0.08)^3 + (1 + 0.08)^2 + (1 + 0.08)^1 + 1 \}$$

Method 2: Using FVIF Appendix 2:

$$FVA_n(M) = M \times FVIF_a(4\text{ years}, 8\%)$$

	Units	Value
Current wattage of bulb	W	300
Replace with	W	30
Electricity usage hours per year	h/yr	8760
Electricity savings per year	Wh/yr	2365200
1 kWh	Wh	1000
Savings in electricity	kWh/yr	2365.2
Cost of electricity	BDT/kWh	5
Cost savings per year	BDT/yr	11826
Thus, the savings associated with this project form an annuity of BDT 11826 per year.		

Annuity per year	BDT/yr	11826
Interest rate	%	8
Future value at end of	years	4
Future value of annuity at end of 4 years	BDT	53289

Method 3: MS Excel Formula = FV(rate, no. of periods, M)

C14

⌵

:

✕

✓

fx

=FV(C12%,C13,C11)

	A	B	C	D
1			Value	units
2	Current wattage of bulb	=	300	W
3	Replace with	=	30	W
4	Electricity usage hours per year	=	8760	h/yr
5	Electricity savings per year	=	2365200	Wh/yr
6	1 kWh	=	1000	Wh
7	Savings in electricity	=	2365.2	kWh/yr
8	Cost of electricity	=	5	BDT/kWh
9	Cost savings per year	=	11826	BDT/yr
10	Thus, the savings associated with this project form an annuity of BDT 11826 per year.			
11	Annuity per year	=	11826	BDT/yr
12	Interest rate	=	8	%
13	Future value at end of	=	4	years
14	Future value of annuity at end of 4 years	=	53289	BDT

The present value of an annuity is the opposite of the future value (sum) of an annuity. The present value of an annuity is the BDT value that answers this question: What fixed amount today will accumulate after the given number of years to exactly the same amount as the sum (future value) of the annuity? It is given by the following formula:

$$PVA_{n_0}(\text{BDT } 1) = PVIF(1 \text{ year}, r) + PVIF(2 \text{ year}, r) + \dots + PVIF(n \text{ year}, r)$$

Where,

$PVA_n(\text{BDT } 1)$ = Present value of an annuity of BDT1 for n time periods at 'r' rate of interest.

PVIF = Present Value interest factor (the Present Value of BDT 1) associated with the given interest rate and year in the future.

Example 9: The present value of an annuity

A star hotel to reduce electricity costs considered replacing CFL bulbs of a certain wattage with LED bulbs of a lower wattage in every hallway of a hotel. These bulbs have an expected life of 8 years, and will save BDT 1300 per year for the 8-year period. The interest rate is 6%.

Find: The present value of the cost savings.

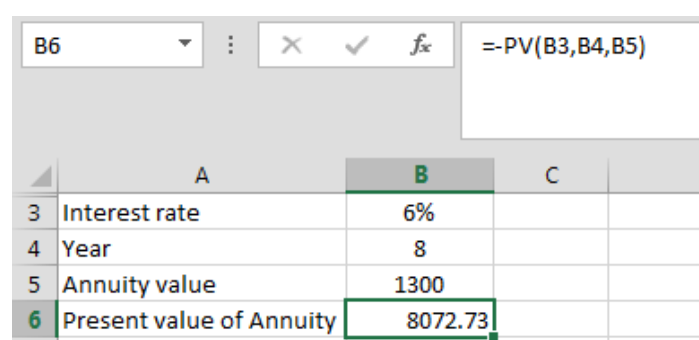
Solution:

Method 1: Using PVIF Factor (Appendix 1)

The cost savings form an annuity of BDT 1300 per year for 8 years. The cost savings associated with each year will be discounted @ 6% individually back to the present, and the sum will be taken as shown in table below.

Year	Cost Savings (BDT)	PVIF	Present value (BDT)
1	1300	0.9434	1226.42
2	1300	0.8900	1157
3	1300	0.8396	1091.48
4	1300	0.7921	1029.73
5	1300	0.7473	971.49
6	1300	0.7050	916.5
7	1300	0.6651	864.63
8	1300	0.6274	815.62
Present value of Annuity			8072.87

Method 2: Using MS Excel Formula:



The screenshot shows an Excel spreadsheet with the following data:

	A	B	C
3	Interest rate	6%	
4	Year	8	
5	Annuity value	1300	
6	Present value of Annuity	8072.73	

The formula bar shows the formula: `=-PV(B3,B4,B5)`

However, in reality costs change annually so does savings leading to non-uniform/irregular flow of cost savings. For example the cost of LED bulbs may reduce or cost of electricity may rise annually. In such cases annuity is calculated by taking the sum of the present value of the savings associated with each year.

Example 10: Present value of an Irregular flow cost savings

Modern retail stores prefer giving customer's good shopping experience and offer choices to see and feel the goods before purchasing. Accordingly a modern retail store conducting business for 310days/yr (12 h/d, Monday through Saturday) in an area of 25000 ft² floor space illuminated its store using 400 fixtures having four 40W bulbs in each fixture. To reduce electricity costs while maintaining visual comfort the store was recommended to remove two lamps from every other light fixture in store. The cost of electricity is BDT 5 per kWh and the contract ensures the same cost for the next 5 years, after which it will increase to BDT 5.5 per kWh. The relevant interest rate is 10%.

Find: The annual cost savings associated with this project, and the present value of these savings over the next 10 years.

Solution:

	Unit	Value
Floor area of store	ft ²	25000
Business hours per year	h/yr	3720
Total no. of light fixtures at store	nos.	400
No. of bulbs in each fixture	nos.	4
Wattage of each bulb	W	40
Cost of electricity for first 5 years	BDT/kWh	5
Cost of electricity for next 5 years	BDT/kWh	5.5
No. of fixtures where change is made	nos	200
No. of lamps removed at each fixture	nos	2
Electricity saved per fixture	W	80
Watts conserved in store area	W	16000 = 16KW
Amount of energy saved per year	kWh/yr	59520
Cost savings for first 5 years	BDT/y	297600
Cost savings for next 5 years	BDT/y	327360

So, the savings of the project form an annuity of 297600/yr for first 5 years, followed by another 5 year annuity of 327360/yr. The present value of these cost savings may be determined by finding the present value of the cost savings associated with each year (a series of fixed amounts) and then taking their sum. This process is shown below.

Year	Cost savings(BDT)	PVIF (Appendix 1)	Present Value(BDT)
1	297600	0.9091	270548
2	297600	0.8264	245937
3	297600	0.7513	223587
4	297600	0.6830	203261
5	297600	0.6209	184780
6	327360	0.5645	184795
7	327360	0.5132	168001
8	327360	0.4665	152713
9	327360	0.4241	138833
10	327360	0.3855	126197

These can be assessed using energy and economic efficiency and marginal analysis of cost and savings as explained below.

Method 3: Using MS Excel Formula:

	G	H	I
14	Cost Savings for 1st five years		297600
15	Cost savings for next five years		327360
16	Rate of Interest		10%
17	Present Value of savings for first 5 years		1128138
18	Value of savings from 6th year to 10th year at		1240952
19	Present Value of savings from 6th to 10th year		770534
20	Present Value		1898672

1.5. Financial Analysis Techniques

For management to consider any energy project the overall costs of all possible alternatives should be known and the project should save at least as much as it costs. Depending on the complexity and level of investment the following techniques can be used.

The basic criteria for financial investment appraisal include:

- **Simple Payback-** a measure of how long it will be before the investment makes money, and how long the financing term needs to be
- **Return on Investment (ROI) and Internal Rate of Return (IRR)-** measure that allow comparison with other investment options
- **Net Present Value (NPV)** and Cash Flow - measures that allow financial planning of the project and provide the company with all the information needed to incorporate
- Energy efficiency projects into the corporate financial system.

Initially, when you can identify no or low cost investment opportunities, this principle should not be difficult to maintain. However, if your organization decides to fund a rolling program of such investments, then over time it will become increasingly difficult for you to identify opportunities, which conform to the principle. Before you'll reach this position, you need to renegotiate the basis on which investment decisions are made.

It may require particular thoroughness to ensure that all the costs and benefits

arising are taken into account. As an approximate appraisal, simple payback (the total cost of the measure divided by the annual savings arising from it expressed as years required for the original investment to be returned) is a useful tool.

As the process becomes more sophisticated, financial criteria such as Discounted Cash Flow, Internal Rate of Return and Net Present Value may be used. If you do not possess sufficient financial expertise to calculate these yourself, you will need to ensure that you have access, either within your own staff or elsewhere within the organization, to people who can employ them on your behalf.

There are two quite separate grounds for arguing that, at least long after their payback periods. Such measure does not need to be written off using fast discounting rates but can be regarded as adding to the long term value of the assets. For this reason, short term payback can be an inadequate yardstick for assessing longer term benefits. To assess the real gains from investing in saving energy, you should use investment appraisal techniques, which accurately reflect the longevity of the returns on particular types of technical measures.

1.5.1 Simple Pay Back Period

Simple Payback Period (SPP) represents, as a first approximation; the time (number of years) required to recover the initial investment (First Cost), considering only the Net Annual Saving. The annual net cost saving is the least savings achieved after all the operational costs have been met. This is the simplest technique that can be used to appraise a proposal, despite its limitations that it does not consider cash-flows after the payback period, which may be substantial. Hence It can be considered as a metric to measure a project's capital recovery and not profitability.

The simple payback period is usually calculated as follows:

$$\text{Simple payback period (years)} = \frac{\text{Capital cost of the project (in BDT)}}{\text{Net Annual Savings (in BDT)}}$$

Example 11 : Calculating pay-back period.

A new small cogeneration plant installation is expected to reduce a company's annual energy bill by BDT 4,86,000. If the capital cost of the new boiler installation is BDT22,20,000 and the annual maintenance and operating costs are BDT 42,000, the expected payback period for the project can be worked out as follows.

Solution

$$\text{Payback} = \frac{22,20,000}{(4,86,000 - 42,000)} = 5 \text{ years}$$

According to the payback criterion, the shorter the payback period, the more desirable the project

Example 12: Payback Period when savings each year are equal

A SME (Small and Medium scale enterprise) considered a desktop computer with energy monitoring and management software to pursue energy conservation opportunities. The system has an original cost of BDT3,20,000 and will generate net after tax savings of BDT 40,000 per year.

Find: The payback period of this investment

Solution:

$$\text{Payback period} = \frac{\text{BDT } 320000}{\text{BDT } 40000} = 8 \text{ years}$$

If savings each year are not constant then the above equation is not applicable. In such case savings from each year are added until their sum equals the original investment. An example is shown below.

Example 13: Payback period when savings each year are not constant

In the above example (example 13)), suppose the annual net cost savings is BDT40,000 for the first year will increase 12% each year thereafter, whereas, the original price of the system remains at BDT 3,20,000. Find the payback period of this investment.

Solution: Consider the following table.

Table: Payback period with an irregular flow of cost savings

Year	Original Savings (first year)(BDT)	Escalation FVIP 12%	Actual savings for year(BDT)	Cumulative savings at end of year(BDT)
0	40000	Given	40000	40000
1	40000	1.12	44800	84800
2	40000	1.2544	50176	134976
3	40000	1.4049	56196	191172
4	40000	1.5735	62940	254112
5	40000	1.7623	70492	324604

The Table above shows, the total cost savings of the project become equal to its cost at the end of the fifth year. Thus, a rough estimate of the payback period is 5 years.

Advantages

A widely used investment criterion, the payback period seems to offer the following advantages:

- It is simple, both in concept and application. Obviously a shorter payback generally indicates a more attractive investment. It does not use tedious calculations.
- It favours projects, which generate substantial cash inflows in earlier years, and discriminates against projects, which bring substantial cash inflows in later years but not in earlier years.

Limitations

- It fails to consider the time value of money. In the above example the net cost savings of 5th year are counted equally with those of the first year. This violates the most basic principle of financial analysis, which stipulates that cash flows occurring at different points of time can be added or subtracted only after suitable compounding/discounting.
- The payback method does not consider savings that are accrued after the payback period has finished. This leads to discrimination against projects that generate substantial cash inflows in later years.

Example 14 : Understanding limitation of pay-back period

To consider impact of cash flows after the payback period is over, consider the cash flows of two projects, A and B: The payback criterion prefers A, which has a payback period of 3 years, in comparison to B, which has a payback period of 4 years, even though B has very substantial cash inflows in years 5 and 6.

Investment/ Savings in Year	Cash Flow of A (BDT)	Cash Flow of B (BDT)
1	50,000	20,000
2	30,000	20,000
3	20,000	20,000
4	10,000	40,000
5	10,000	50,000
6	-	60,000

1.5.2 Return on Investment (ROI)

ROI expresses the "annual return" from the project as a percentage of capital cost. The annual return takes into account the cash flows over the project life and the discount rate by converting the total present value of ongoing cash flows to an equivalent annual amount over the life of the project, which can then be compared to the capital cost. ROI does not require similar project life or capital cost for comparison.

This is a broad indicator of the annual return expected from initial capital investment, expressed as a percentage:

$$ROI = \frac{\text{Annual Net Cash Flow}}{\text{Capital Cost}} \times 100$$

Limitations

- It does not take into account the time value of money.
- It does not account for the variable nature of annual net cash in flows.

Example 15: Calculating rate of return

A municipality replaced 1000,40 W CFL street light bulbs with 25 W LED bulbs investing BDT 30,00,000. The life of LED bulbs is 10 years. The annual electricity savings due to replacement of bulbs is 65700 kWh considering 12 hrs operation. Assuming electricity cost of BDT 5.0, annualised yearly savings are BDT 201849 considering interest rate of 10%. The return on investment would be:

$$ROI = \frac{201849}{3000000} \times 100 = 6.73\%$$

1.5.3 Benefit-Cost Analysis

The net cost savings of an energy project are often called the benefits of the project. If the actual net cost savings per year are identical and known, they can be used to compute the benefit-cost ratio. The formula for this ratio is as follows:

$$\frac{\text{Benefit}}{\text{Cost}} = \frac{\text{Actual net cost savings/yr}}{\text{Net cost savings/yr needed to recover original investment}}$$

If the benefit-cost ratio is larger than one, then the net cost savings of a project (or its benefits) exceed its cost and the investment is profitable. If the ratio is less than one, then the net cost savings needed per year are greater than those

actually obtained and the investment is not profitable.

1.5.4 Profitability index

Another technique, which can be used to evaluate the financial viability of projects, is the profitability index. The profitability index can be defined as:

$$\text{Profitability Index} = \frac{\text{Sum of the discounted net savings}}{\text{Capital Costs}}$$

The higher the profitability index, the more attractive the project.

Example 16 : Calculating and comparing profitability index of two different projects

Consider two projects A and B with investment of BDT 30,000 in project A and BDT 35000 in project B. The assessment of profits indicate project A generates profit of BDT 10,254 and project B generates profit of BDT 10,867 over the life of project tenure. The profitability index can be calculated as given below.

$$\text{For Project A: Profitability index} = \frac{10,254}{30,000} = 0.342$$

$$\text{For Project B: Profitability index} = \frac{10,867}{33,000} = 0.33$$

Project A is therefore a better proposal than Project B.

This index is a quick tool to consider the better alternative among two different proposed projects.

1.6. Discounted Cash Flow Methods

In order to overcome the weakness of simple pay-back assessment method a number of discounted cash flow techniques have been developed, which are based on the fact that money invested in a bank will accrue annual interest. If a fixed amount of money or a series of equal, yearly cost savings (an-annuity) is associated with a certain time period, then an amount associated with the present – which is equal to the future amount can be calculated. The latter figure is the present value of the fixed amount, or the annuity. This process is called discounting. The two most commonly used techniques are the 'net present value' and the 'internal rate of return' methods.

1.6.1 Net Present Value

Because an amount of money in the present is worth more than the same amount at any point in the future due to time value of money, all amounts should be converted to the same period to arrive at net present value. The net present value method achieves this by quantifying the impact of time on any particular future cash flow. This is done by equating each future cash flow to its current value today, in other words determining the present value of any future cash flow. The present value (PV) is determined by using an assumed interest rate, usually referred to as a discount rate. Discounting is the opposite process to compounding. Compounding determines the future value of present cash flows, where" discounting determines the present value of future cash flows. The net present value (NPV) of a project is equal to the sum of the present values of all the cash flows associated with it. Symbolically,

$$NPV = \frac{CF_0}{(1+k)^0} + \frac{CF_1}{(1+k)^1} + \dots + \frac{CF_n}{(1+k)^n} = \sum_{t=0}^n \frac{CF_t}{(1+k)^t}$$

Where

NPV = Net Present Value

CF_t = Cash flow occurring at the end of year 't' (t=0,1,...,n)

n = life of the project

k = Discount rate

The discount rate (k) employed for evaluating the present value of the expected future cash flows should reflect the risk of the project.

Example 17: Calculating NPV

To illustrate the calculation of net present value, consider a project, which has the following cash flow stream:

Investment/Savings year-wise	Cash Flow (BDT)
1	200,000
2	200,000
3	300,000
4	300,000
5	350,000

The cost of capital, k, for the firm is 10 per cent. The net present value of the proposal is:

$$NPV = -\frac{1,000,000}{(1.10)^0} + \frac{200,000}{(1.10)^1} + \frac{200,000}{(1.10)^2} + \frac{300,000}{(1.10)^3} + \frac{300,000}{(1.10)^4} + \frac{350,000}{(1.10)^5} = 5,273$$

Example 18: Calculating NPV

In a cement plant, 16000 litre lubricant/yr is used to manually lubricate grinding equipment gear trains every 2 hours, using. An automatic oil-mist system was proposed by a supplier claiming that his automatic system uses only 600liters/yr without compromising on lubricating functionality. The gear lubricant costs BDT 100/litre. The expected life of the system is 5 years. The system would cost BDT 6,00,000 to purchase and install. Maintenance costs would be BDT 37000/yr. The interest rate is 9%. Find the net present value of installing the automatic oil-mist system.

Solution:

	unit	value
Current lubricant usage	lit/yr	16000
Cost of lubricant	BDT/lit	100
Lubricant required in new oil-mist system	lit/yr	600
Life of new system	yr	5
Capital cost of new system	BDT	6,00,000
Maintenance cost of new system	BDT/yr	37000
Interest rate	%	9
Solution		
Lubricant savings due to new system	lit/yr	15400
Cost savings	BDT/yr	5,40,000
Thus, the cost savings associated with this project form an annuity of BDT 154000/yr for 5 years. The present value of this annuity is as follows:		
PV(cost savings)	BDT	59,90,063
PV(maintenance requirement)	BDT	1,43,917
Present value of the purchase of installation and maintaining new system		
PV(all costs of new system)	BDT	7,43,917
Net Present Value (NPV)	BDT	52,46,146
Since NPV > 0 the project should be implemented		
Alternate method:		
net cost savings/yr (Savings – Cost)	BDT/yr	1503000
Present value of net cost savings	Net savings/yr x PVIFa (5 years, 9%)	
	BDT	5846146
Net Present value	PVof(net cost savings - Capital cost)	

	BDT	5246146

When analysing one particular project, the NPV methods offers no special advantage. However, the NPV methods becomes most useful when a particular function can be performed in more than one way.

Example 19: Comparing NPV of different options

Example: Suppose that in Examples above, 4 different oil-mist systems were available at differing costs, each system could reduce costs by a different amount, and each had a NPV greater than zero (total cost savings exceed total costs in present-value terms).

Choice among alternative Oil-mist systems

System	Capital Cost (BDT)	Maintenance cost (BDT/yr)	Cost Savings (BDT)	NPV (BDT)
1	4,00,000	60,000	10,00,000	32,56,272
2	5,00,000	55,000	12,00,000	39,53,651
3	5,50,000	45,000	15,00,000	51,09,443
4	6,00,000	25,000	15,00,000	51,37,236

In this example, System 4 would be implemented since it has the highest NPV. Once the alternative ways of achieving a goal have been determined, the NPV method can be used to choose from among the alternatives.

However, it is common practice to use a discount factor (DF) when calculating present value. The discount factor is based on an assumed discount rate (i.e. interest rate) and can be determined by using equation.

$$DF = (1 + \frac{IR}{100})^{-n}$$

The product of a particular cash flow and the discount factor is the present value.

$$PV = S \times DF$$

The values of various discount factors computed for a range of discount rates (i.e. interest rates) are shown in the annexure-1.

Example 20: Evaluation of financial merits using NPV

Using the net present value analysis technique evaluate the financial merits of the proposed projects shown in the table below assuming an annual discount rate of 8%.

	Project A	Project B

Capital cost in BDT	30,000	30,000
Year	Net annual savings (BDT)	Net annual savings (BDT)
1	6,000	6,600
2	6,000	6,000
3	6,000	6,300
4	6,000	6,300
5	6,000	6,000
6	6,000	6,000
7	6,000	5,700
8	6,000	5,700
9	6,000	5,400
10	6,000	5,400
Total net savings at the end of year 10	60,000	60,000

Solution

The annual cash flows should be multiplied by the annual discount factors for a rate of 8% to determine the annual present values, as shown in the table below:

Formula : $NPV_{Benefits} = NPV_{Savings} - Capital\ Cost$

Year	Discount Factor for 8% (a)	Project A		Project B	
		Net savings (BDT) (b)	Present value (BDT) (a*b)	Net savings (BDT) (b)	Present value (BDT) (a*b)
0	1.000	(30,000)	(30,000)	(30,000)	(30,000)
1	0.926	6,000	5,556.00	6,600	6,111.60
2	0.857	6,000	5,142.00	6,000	5,656.20
3	0.794	6,000	4,764.00	6,300	5,002.20
4	0.735	6,000	4,410.00	6,300	4,630.50
5	0.681	6,000	4,086.00	6,000	4,086.00
6	0.630	6,000	3,780.00	6,000	3,780.00
7	0.583	6,000	3,498.00	5,700	3,323.10
8	0.540	6,000	3,240.00	5,700	3,078.00
9	0.500	6,000	3,000.00	5,400	2,700.00
10	0.463	6,000	2,778.00	5,400	2,500.20
		NPV=10,254		NPV=10,868	

Method 2: Using MS Excel

In Excel for each year PV is calculated according to formulas explained in earlier examples. The sum of present values gives the NPV.

The net present value represents the net benefit over and above the compensation for time and risk.

It can be seen that over a 10 year life-span the net present value of Project A is BDT 10,254, while for Project B it is BDT 10,868. Therefore Project B is the preferential proposal.

Hence the decision rule associated with the net present value criterion is: "Accept the project if the net present value is positive and reject the project if the net present value is negative".

Advantages

The net present value criterion has considerable merits.

- It takes into account the time value of money.
- It considers the cash flow stream in its project life.

Limitations:

The whole credibility of the net present value method depends on a realistic prediction of future interest rates, which can often be unpredictable. It is prudent therefore to set the discount rate slightly above the interest rate at which the capital for the project is borrowed. This will ensure that the overall analysis is slightly pessimistic, thus acting against the inherent uncertainties in predicting future savings.

1.6.2 Internal Rate of Return

This method calculates the rate of return that the investment is expected to yield. The internal rate of return (IRR) method expresses each investment alternative in terms of a rate of return. The expected rate of return is the interest rate for which total discounted benefits become just equal to total discounted costs (i.e. net present benefits or net annual benefits are equal to zero, or for which the benefit / cost ratio equals one). The criterion for selection among alternatives is to choose the investment with the highest rate of return.

The discount rate which achieves a net present value of zero is known as the internal rate of return (IRR) The higher the internal rate of return, the more attractive the project.

The rate of return is usually calculated by a process of trial and error, whereby the net cash flow is computed for various discount rates until its value is reduced to zero and is calculated using the equation given below.

$$0 = \frac{CF_0}{(1+k)^0} + \frac{CF_1}{(1+k)^1} + \dots + \frac{CF_n}{(1+k)^n} = \sum_{t=0}^n \frac{CF_t}{(1+k)^t}$$

Where,

CF_t cash flow at the end of year "t"

k discount rate

n life of the project

- **CF_t is negative if expenditure > savings**
- **CF_t is positive if expenditure < savings.**

In the net present value calculation we assume that the discount rate (cost of capital) is known and determine the net present value of the project. In the internal rate of return calculation, we set the net present value equal to zero and determine the discount rate (internal rate of return), which satisfies this condition.

Example 21: Evaluate internal rate of return

To illustrate the calculation of internal rate of return, consider the cash flows of a project:

Year	0	1	2	3	4
Cash Flow	(1,00,000)	30,000	30,000	40,000	45,000

The internal rate of return is the value of "K" which satisfies the following equation:

$$1,00,000 = \frac{30,000}{(1+k)^1} + \frac{30,000}{(1+k)^2} + \frac{40,000}{(1+k)^3} + \frac{45,000}{(1+k)^4}$$

The calculation of "K" involves a process of trial and error. We try different values of "K" till we find that the right-hand side of the above equation is equal to 1,00,000. Let us, to begin with, try K-15 per cent. This makes the right-hand side equal to:

$$\frac{30,000}{(1.15)} + \frac{30,000}{(1.15)^2} + \frac{40,000}{(1.15)^3} + \frac{45,000}{(1.15)^4} = 1,00,802$$

This value is slightly higher than our target value, 100,000. So we increase the value of k from 15 per cent to 16 per cent. (In general, a higher k lowers and a smaller k increases the right-hand side value). The right-hand side becomes:

$$\frac{30,000}{(1.16)} + \frac{30,000}{(1.16)^2} + \frac{40,000}{(1.16)^3} + \frac{45,000}{(1.16)^4} = 98,641$$

Since this value is now less than 100,000, we conclude that the value of k lies between 15 per cent and 16 per cent. For most of the purposes this indication suffices.

Example 22: Calculate the internal rate of return (IRR)

The manager of a warehouse is considering the installation of an air lock at the loading door. The size of the door is 20 ft x 17.5 ft. The door is open for 10 minutes - 12 times a day – 5 days per week. The inside building temperature is 70°F. The heating season is October – April (30 weeks). The average outside temperature during the heating season is 38.4°F. The air flow velocity through the open door is 500 fpm. Steam, which supplies 2100 Btu/kg, is used for heating. The cost of steam is BDT 0.5/kg. The cost of the air-lock is BDT 17,70,000 installed. Assume the life of the air lock is 20 years.

Find the internal rate of return (IRR) of the purchase and installation cost of the air lock.

Use conversion factor: 0.0183 Btu = 1 ft³-°F.

	Unit	Value
Door size	ft	20 x 17.5
Area of door	ft ²	350
Door opening time	minutes	10
No. of times it is opened in a day	nos	12
No .of days it is opened in a week	nos	5
No. of weeks heating is required	nos	30
Inside building temperature	°F	70
Outside temperature	°F	38.4
Air flow velocity	fpm	500
Heat value of steam	Btu/kg	2100
Cost of steam	BDT/kg	0.5
0.0183Btu supplied to 1 ft ³ air raises temp by 1°F	ft ³ -°F	1
Cost of air lock installed	BDT	17,00,000
Life of air lock	years	20
Conversion factor	BTU ft ³ °F	0.0183
Solution:		

Air entering door	ft ³ /min	175000
Temperature difference between inside and outside	°F	31.6
Heat loss	Btu/min	101199
Heating cost per min of door opening	BDT/min	24.095
Annual cost savings due to installation of air lock	BDT/yr	433710
Thus, this project yields uniform savings of BDT 433710/yr over its life.		
Proper PVla (20 years, ?%)		3.920
From Appendix 3, for 20 year period the proper PVla of 3.92 corresponds to 25% interest PVla of 3.954 and 26% interest PVla of 3.808. Since the PVla needed is equal to 3.920 the exact value of internal rate of return (i) can be interpolated as follows.		
$i = 0.25 + (0.26 - 0.25) \times 3.954 / (3.954 + 3.808) = 0.255, \text{ or } 25.5 \text{ percent}$		

Example 23: Assess project whether it will achieve desired IRR

A proposed project requires an initial capital investment of BDT 20,000. The cash flows generated by the project are shown in the table below:

Year	Cash flow (BDT)
0	(20,000)
1	6,000
2	5,500
3	5,000
4	4,500
5	4,000
6	4,000

Given the above cash flow data, let us find out the internal rate of return for the project.

Solution

Year	Cash flow (BDT)	8% discount rate		12% discount rate		16% discount rate	
		Discount factor	Present value (BDT)	Discount factor	Present value (BDT)	Discount factor	Present value (BDT)
0	(20,000)	1.000	(20,000)	1.000	(20,000)	1.000	(20,000)
1	6,000	0.926	5,560	0.893	5,358	0.862	5,172

2	5,500	0.857	4,713.5	0.797	4,383.5	0.743	4,086.5
3	5,000	0.794	3,970	0.712	3,560	0.641	3,205
4	4,500	0.735	3,307.5	0.636	2,862	0.552	2,484
5	4,000	0.681	2724	0.567	2,268	0.476	1,904
6	4,000	0.630	2520	0.507	2,028	0.410	1,640
			NPV=2791			NPV=459.5	NPV=(1,508.5)

It can clearly be seen that the discount rate which results in the net present value being zero lies somewhere between 12% and 16%.

For 12% discount rate, NPV is positive; for 16% discount rate, NPV is negative. Thus, for some discount rate between 12 and 16 percent, present value benefits are equated to present value costs. To find the value exactly, one can interpolate between the two rates as follows:

$$\text{Internal rate of return} = 0.12 \times (0.16 - 0.12) \times \frac{459.5}{(459 - (-1,508.5))} \times 100$$

$$\text{Internal rate of return} = 12.93\%$$

Thus, the internal rate of return for the project is 12.93 %. At first sight both the net present value and internal rate of return methods look very similar, and in some respects are. Yet there is an important difference between the two. The net present value method is essentially a comparison tool, which enables a number of projects to be compared, while the internal rate of return method is designed to assess whether or not a single project will achieve a target rate of return.

Advantages

A popular discounted cash flow method, the internal rate of return criterion has several advantages:

- It takes into account the time value of money.
- It considers the cash flow stream in its entirety.
- It makes sense to businessmen who prefer to think in terms of rate of return and find an absolute quantity, like net present value, somewhat difficult to work with.

Limitations

A central point of criticism of the IRR Method is the implicit reinvestment assumption, which can lead to unrealistically high profitability rates. The IRR method should consequently be backed by a NPV calculation.

Example 24: Calculate IRR based on project savings

Calculate the internal rate of return (i) for an economizer that will cost BDT 500,000, will last 10 years, and will result in fuel savings of BDT 150,000 each year. Find the 'i' that will equate the following:

$$\text{BDT } 500,000 = 150,000 \times \text{PV} (A = 10 \text{ years, } i = ?)$$

To do this,

Step I: Calculate proper PVla

$$\text{Proper PVla} = \frac{\text{Cost}}{\text{Annual savings}} = \frac{500000}{150000} = 3.33$$

From PVla Table in Appendix 3, for 10 years period check PVla values corresponding to proper PVla i.e., 3.33. As can be seen from PVla table, the IRR falls between 27% and 28% with PVla of 3.364 and 3.269.

To find the rate more exactly, one can interpolate between the two rates as follows:

$$i = 0.27 + (0.28 - 0.27) \times 3.364 / (3.364 + 3.269) = 0.275, \text{ or } 27.5 \text{ percent}$$

1.6.3 Modified Internal Rate of Return

Whenever the cost savings of an energy project are not the same each year, then the preceding techniques cannot be used to determine IRR. The present value of the net cost savings of each year should be discounted back to the present and summed, using various interest rates. That interest rate, which leads to a total present value of net cost savings that is very close to the original cost of the project, is the approximate internal rate of return.

In order to eradicate the limitation of the conventional IRR method, the modified IRR method replaces the implicit reinvestment assumption with an explicit reinvestment rate. This method requires an external project-unrelated investment opportunity rate. All positive future cash flows are discounted with this external interest rate to acquire their respective present value. Possible reinvestment rates are:

- Average corporate return rate: Applicable in case the cash returns are invested in the operating activities of a company.
- Achievable interest rate in the capital market: Cash returns are invested in the capital market.
- Loan interest rate: In case the cash returns are used to repay loans, the respective loan interest rate should be used.

The MIRR is calculated as follows:

$$IRR_{mod} = \sqrt[n]{\frac{\sum_{t=1}^n E_t \times (1 + r_{EXT})^{n-t} + R_n}{\sum_{t=0}^n A_t \times (1 + r_{EXT})^{-t}}} - 1$$

Where

IRR_{mod}	= modified Internal Rate of Return
A_t	= negative Cash Flows at timet
E_t	= positive Cash Flows at timet
r_{EXT}	= reinvestmentrate
n	= operatinglife
R_n	= remaining value at timen

1.7 Comparison of Project Evaluation Methods

Method	Needed Information	Result
Capital recovery factor and benefit-cost	- Original cost; - Life of investment; - Relevant interest rate	- Needed cost savings per year to recover original investment; - Ratio that shows how cost savings relate to cost
Net Present value	- Original cost; - Life of investment; - Relevant interest rate; - Net cost savings per year	How much total present value of net cost savings exceeds (or less than) original cost
Internal Rate of Return	- Original cost; - Life of net cost savings per year	Interest rate which shows how net cost savings relate to original cost
Payback period	- Original cost; - Net cost savings per year	Rough estimate of time needed to recover original cost.

2. Sensitivity and Risk Analysis

Many of the cash flows in the project are based on assumptions that have an element of uncertainty. The present day cash flows, such as capital cost, energy cost savings, maintenance costs, etc. can usually be estimated fairly accurately. Even

though these costs can be predicted with some certainty, it should always be remembered that they are only estimates. Cash flows in future years normally contain inflation components which are often "guesstimates" at best. The project life itself is an estimate that can vary significantly.

Sensitivity analysis is an assessment of risk. Because of the uncertainty in assigning values to the analysis, it is recommended that a sensitivity analysis be carried out - particularly on projects where the feasibility is marginal.

- How sensitive is the project's feasibility to changes in the input parameters?
- What if one or more of the factors in the analysis is not as favourable as predicted?
- How much would it have to vary before the project becomes unviable?
- What is the probability of this happening?

Suppose, for example, that a feasible project is based on an energy cost saving that escalates at 10% per year, but a sensitivity analysis shows the break-even is at 9% (i.e. the project becomes unviable if the inflation of energy cost falls below 9%). There is a high degree of risk associated with this project - much greater than if the break-even value was at 2%.

Many of the computer spreadsheet programs have built in "what if" functions that make sensitivity analysis easy. If carried out manually, the sensitivity analysis can become laborious - reworking the analysis many times with various changes in the parameters.

Sensitivity analysis is undertaken to identify those parameters that are both uncertain and for which the project decision, taken through the NPV or IRR, is sensitive. Switching values showing the change in a variable required for the project decision to change from acceptance to rejection are presented for key variables and can be compared with post evaluation results for similar projects.

For large projects and those close to the cut-off rate, a quantitative risk analysis incorporating different ranges for key variables and the likelihood of their occurring simultaneously is recommended. Sensitivity and risk analysis should lead to improved project design, with actions mitigating against major sources of uncertainty being outlined

The various micro and macro factors that are considered for the sensitivity analysis are listed below.

Micro factors

- Operating expenses (various expenses items)
- Capital structure
- Costs of debt, equity
- Changing of the forms of finance e.g. leasing
- Changing the project duration

Macro factors

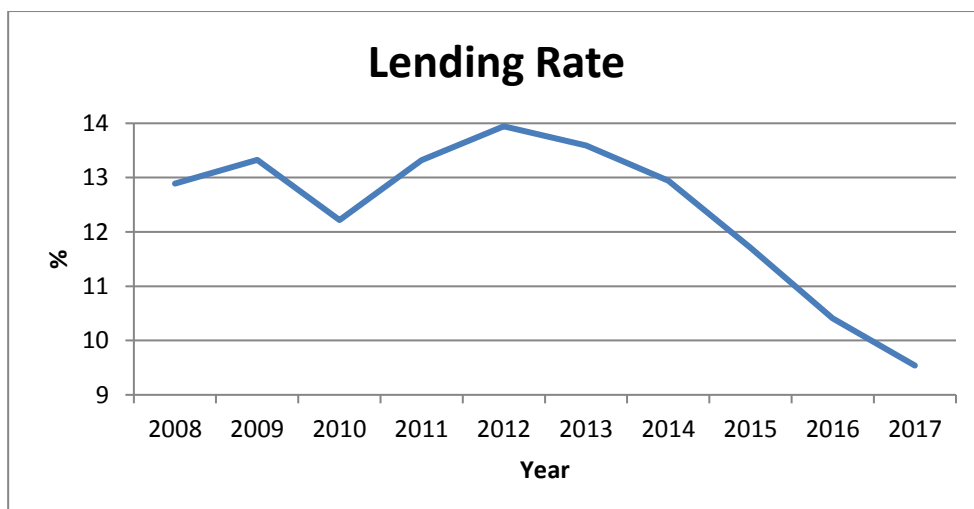
Macro-economic variables are the variable that affects the operation of the industry of which the firm operates. They cannot be changed by the firm's management. Macro-economic variables, which affect projects, include among others:

- Changes in interest rates
- Changes in the tax rates
- Changes in the accounting standards e.g. methods of calculating depreciation
- Changes in depreciation rates
- Extension of various government subsidized projects e.g. extension of subsidies for setting up industries in under-developed regions or subsidizing renewables use etc.
- General employment trends e.g. improved employment conditions result in shortage of skilled man-power and thereby increases their hiring costs and salaries.
- Imposition of regulations on environmental and safety issues in the industry
- Energy Price change
- Technology changes

The sensitivity analysis will bring changes in various items in the analysis of financial statements or the projects, which in turn might lead to different conclusions regarding the implementation of projects.

2.1 Impact of interest rates on cash flows

In assessing likely interest out-go, it needs to be appreciated that interest rates charged may be fixed or variable. For assessment purposes long time average rates may be considered. The interest rate trend for Bangladesh is shown in figure below.



Source : World Bank

Figure: Lending Rate in Bangladesh

2.2 Impact of Depreciation rates on cash flows

In the above sections and examples the basic principles associated with the financial analysis of projects were considered, but they do not consider the following important issues:

- The capital value of plant and equipment generally depreciates overtime.
- General inflation reduces the value of savings as time progresses. For example, BDT 1000 saved in 1 years' time will be worth more than BDT 1000 saved in 10 years' time.

These issues are addressed by considering the income-relevant decrease of the value of the investment called depreciation or amortization. While there are various methods available, national legislations usually dictate the method to be used to determine amortization and depreciation expenses. Knowledge of legislated depreciation rates may help in minimizing tax outflows, for example accelerated depreciation is allowed for energy efficient or clean energy products or technologies. The most commonly used methods to calculate depreciation are as follows.

- Straight line method
- Reducing balance method
- Sum of years depreciation method
- Units of production depreciation method

2.2.1 Straight-line Depreciation

Straight-line depreciation is the simplest and most common type of depreciation. It is

calculated by dividing the initial asset value of the investment by its operating lifetime. The depreciation amount is consequently identical for every period.

$$\text{Depreciation Amount} = \frac{\text{Initial Value of Asset}}{\text{Operating Lifetime}}$$

Example 25: Calculate straight-line depreciation

Consider a pump which is purchased at BDT 10,000 and has a life of 5 years. Calculate the schedule of depreciation using straight line depreciation method.

$$\text{Depreciation Amount} = \frac{10000}{5} = 2000$$

The pump depreciates by BDT 2000 every year for 5 years. The schedule of depreciation can be tabulated as follows:

Schedule of Depreciation

Year	Depreciation Amount	Remaining Value
0	0	10,000
1	2,000	8,000
2	2,000	6,000
3	2,000	4,000
4	2,000	2,000
5	2,000	0

2.2.2 Reducing-balance Depreciation

The reducing-balance depreciation is characterized by declining depreciation amounts over the duration of an asset's operating lifetime. This is due to depreciation ensues with a constant percentage rate. Depreciation amounts are calculated as follows:

$$\text{Depreciation Amount} = \text{Depreciation Rate} * \text{Remaining Value of the previous year}$$

Example 26: Calculate reducing-balance depreciation

Consider a pump which is purchased at BDT 10,000 and has a life of 5 years and depreciates at a fixed rate of 30% every year. Calculate the schedule of depreciation.

Schedule of Depreciation

Year	Depreciation Amount (BDT) (= 0.3 x Remaining value of previous year)	Remaining Value (BDT)
0	0	10,000
1	3,000	7,000
2	2,100	4,900
3	1,470	3,430
4	1,029	2,401
5	720	1,681

This approach would never reach a remaining value of zero. Therefore, it is common to switch to straight-line depreciation by the time the depreciation amount of the reducing- balance method drops below the depreciation amount of the straight-line method.

Example 27: Assessing when to switch to straight-line method from reducing balance method of depreciation.

Consider a pump which is purchased at BDT 10,000 and has a life of 5 years and depreciates at a fixed rate of 30% every year. Calculate the schedule of depreciation.

Step I: Calculate depreciation value by both methods as given in Table below:

Schedule of Depreciation

Year	Straight – Line method		Reducing balance method	
	Depreciation Amount	Remaining Value	Depreciation Amount	Remaining Value
0	0	10,000	0	10,000
1	2000	8,000	3,000	7,000
2	2000	6,000	2,100	4,900
3	2000	4,000	1,633	3,267
4	2000	2,000	1,633	1,633
5	2000	0	1,633	0

Step II: Check the year in which depreciation amount by reducing-balance method falls below the straight-line value.

As can be seen, in year 3 the depreciation amount of the straight-line method ($4,900/3 = 1,633$) which exceeds the reducing-balance amount (1,470).

Step III: From the year in which the depreciation amount by reducing-balance

method falls below the straight-line value, consider depreciation by straight-line method.

Hence, in the above example, the last three years are depreciated by straight-line method.

2.2.3 Sum of Years Depreciation

Like the previously presented depreciation method, the sum of years depreciation method results in higher depreciation amounts in the early years of an asset. A year's respective depreciation amount is calculated by dividing the total remaining years by the sum of years of operating lifetime and multiplying it with initial asset value. In year three, this would consequently be

$$\text{Depreciation amount (year 3)} = \frac{3}{1 + 2 + 3 + 4 + 5} \times \text{initial Asset Value}$$

Example 28: Calculate depreciation based on sum of years method Schedule of Depreciation

Year	Assessment Method	Depreciation Amount	Remaining Value
0	$\frac{0}{(1 + 2 + 3 + 4 + 5)} \times 10000$	0	10,000
1	$= \frac{5}{(1 + 2 + 3 + 4 + 5)} \times 10000$	3,333	6,667
2	$= \frac{4}{(1 + 2 + 3 + 4 + 5)} \times 10000$	2,667	4,000
3	$= \frac{3}{(1 + 2 + 3 + 4 + 5)} \times 10000$	2,000	2,000
4	$= \frac{2}{(1 + 2 + 3 + 4 + 5)} \times 10000$	1,333	667
5	$= \frac{1}{(1 + 2 + 3 + 4 + 5)} \times 10000$	667	0

2.2.4 Units of Production Depreciation

In this depreciation method the value of the asset is decreased according to the actual usage of the asset. In order to fully depreciate an asset, a total production output has to be presumed. The annual depreciation amounts are calculated as follows:

$$\text{Depreciation amount (year X)} = \frac{\text{Units produced (year X)}}{\text{Total production output}} \times \text{Initial Asset Value}$$

Example 29: Calculate depreciation based on rate of production

It is assumed that an asset with an initial value of 10,000 monetary units will have a total lifetime output of 24,000 units.

Step I: Consider units produced in a particular year

Step II: Calculate ratio of units produced to total lifetime output

Step II: Multiply the ratio with initial value of asset

Schedule of Depreciation

Year	Production Units	Depreciation Amount	Remaining Value
0		0	10,000
1	6,000	2,500	7,500
2	6,000	2,500	5,000
3	5,000	2,083	2,917
4	4,000	1,667	1,250
5	3,000	1,250	0

The capital depreciation of an item of equipment can be considered in terms of its salvage value at the end of the analysis period. The Example 8 illustrates the point.

Example 30: Assessing impact of Salvage Value on NPV

It is proposed to install a heat recovery equipment in a factory. The capital cost of installing the equipment is BDT 20,000 and after 5 years its salvage value is BDT 1500. The savings accrued by the heat recovery device are as shown below. Calculate the net present value after 5 years with and without considering salvage value. Assume discount rate to be 8%.

Savings accrued

Year	1	2	3	4	5
Savings (BDT)	7000	6000	6000	5000	5000

Solution

Year	Discount Factor for 8% (a)	Capital investment (BDT) (b)	Net savings (BDT) (c)	Present value (BDT) (a)*(b+c)
0	1.000	(20,000)		(20,000)
1	0.926		7,000	6,482

2	0.857		6,000	5,142
3	0.794		6,000	4,764
4	0.735		5,000	3,675
5	0.681	1,500	5,000	4,426.5
				NPV=4489.5

It is evident that over a 5-year life span the net present value of the project is BDT 4489.50. Had the salvage value of the equipment not been considered, the net present value of the project would have been only BDT 3468.00.

2.3 Changes in inflation rates: Real value

Inflation can be defined as the rate of increase in the average price of goods and services. In some countries, inflation is expressed in terms of the retail price index (RPI), which is determined centrally and reflects average inflation over a range of commodities. Because of inflation, the real value of cash flow decreases with time. The real value of sum of money (S) realised in n years' time can be determined using the equation.

$$RV = S \times \left(1 + \frac{R}{100}\right)^{-n}$$

Where

- RV real value of S realized in n years' time
- S value of cash flow in n years' time
- R inflation rate(%)

As with the discount factor, it is common practice to use an inflation factor when assessing the impact of inflation on a project. The inflation factor can be determined using the equation.

$$\text{Inflation Factor, } IF = \left(1 + \frac{R}{100}\right)^{-n}$$

The product of a particular cash flow and inflation factor is the real value of the cash flow.

$$RV = S \times IF$$

The application of inflation factors is considered in Example 9.

Example 31: Calculate and assess impact of inflation on NPV of project

Recalculate the net present value of the energy recovery scheme in Example 27, assuming the discount rate remains at 8% and the rate of inflation is 5%.

Solution:

Because of inflation;

$$\text{Real interest rate} = \text{Discount Rate} - \text{Rate of inflation}$$

Therefore Real interest rate = 8 – 5 = 3%

Year	Capital investment (BDT)	Net savings (BDT)	Real Discount Factor for 3%	Present value (BDT)
0	(20,000)		1.000	(20,000)
1		7,000	0.971	6,471
2		6,000	0.943	5,132
3		6,000	0.915	4,743
4		5,000	0.888	3,654
5	1,500	5,000	0.863	4,398
				NPV=4,398

When inflation is not considered the NPV is BDT 4489.5 (ref example 27) and if inflation is considered the NPV is BDT 4,398 demonstrating the depreciation of money value due to inflation.

2.4 Considering Taxes in Financing and Investment

In making investment calculations, the previous elaboration has completely ignored tax issues. In practice, taxes influence the profitability of investments and consequently need to be considered when taking an investment decision.

From the perspective of a company, taxes represent out payments that need to be considered in the cash flows. Taxes can be income-independent and –dependent.

- **Income-independent taxes:** These taxes are usually property and consumer taxes. They can be easily included with the other operational out-payments. While value- added taxes are income-independent taxes as well, they are neglected in financing and investment as it represents a pass-through item.
- **Income-dependent taxes:** These taxes are corporate or income taxes, reducing the cash return of an investment. Essential for the determination of the level of the income-dependent taxes are not the return cash flows but the profit or loss before taxes, which has to be multiplied by the tax rate to find out the required tax payment.

In order to determine the payable income tax of an investment opportunity, taxable profits have to be estimated for every year of operating life by reducing taxable sales

by taxable relevant operating expenses. The latter includes cash expenses like staff and material costs and non-cash expenses like depreciation and amortization. In case debt capital is utilized in financing an investment opportunity, interest obligations have to be considered as well.

The forecast of income-dependent payable taxes is problematic, because the respective tax rate may change over the operating life of an investment due to changes in the political framework as can be seen from the corporate tax rates shown in figure below. The effort for determining payable taxes precisely must consequently be assessed as disproportionately. Thus, investment calculation usually resorts to the simplified specification of payables taxes.



Figure: Corporate Tax Rate: Bangladesh

While the overall corporate tax rate can be considered for preliminary assessment of tax liability there is a need for informing themselves on tax rates that may vary with type of product (Eg: Tax on revenue from renewable power could be less), the scale of industry (Eg: Micro, Small and Medium industries may be given tax preference), market segment for the product (Eg: exports or priority industrial sectors (eg: textile industries) may be taxed less owing to their capacity to earn foreign exchange or generate employment) etc. Hence, it is important to understand and assess tax liability before any investment not only to arrive at real rate of returns but maximize returns utilizing tax exemptions if allowed.

In calculating taxes normally expenses are deducted from the gross revenue earned. After deducting the applicable expenses depending on the tax rate specified for the industry/product, the taxable amount is calculated by multiplying earnings after

deductible expenses with the applicable tax rate.

Example 32: Calculate income tax expenses

Consider a unit with an asset price of 10,000 BDT with an operating lifetime of 5 years and a corporate tax rate of 30 percent. The unit follows the straight-line depreciation method. It is assumed that the project is financing entirely with debt capital at an interest rate of 5 percent. The principal repayment is done uniformly across the life of unit. The operating income generated and expenses incurred are given in table below.

	Year 1	Year 2	Year 3	Year 4	Year 5
Operating income	8,500	9,000	9,500	10,000	10,500
Operating expenses	-1,000	-1,200	-1,400	-1,600	-1,800

Develop an income statement showing depreciation, interest and tax calculations.

- $EBITDA = \text{Operating income} - \text{Operating Expenses}$
- $\text{Depreciation Expenses} = \frac{\text{Initial Value of Asset}}{\text{Operating Lifetime}} = \frac{10000}{5} = 2000$
- $EBIT = EBITDA - \text{Depreciation Expenses}$
- $\text{Interest Expenses} = \text{Remaining Asset value} \times \text{interest rate}$
- $\text{Remaining Asset Value} = \text{Asset Value in previous year} - \text{Yearly Depreciation}$
- $EBT = EBIT - \text{Interest Expenses}$
- $\text{Income tax expenses} = EBIT \times \text{income tax rate}$
- $EAT = EBT - \text{Income Tax expenses}$

Using the above formulae, construct the income statement as given below to assess tax liabilities.

	Year 1	Year 2	Year 3	Year 4	Year 5
Operating income	8,500	9,000	9,500	10,000	10,500
Operating expenses	-1,000	-1,200	-1,400	-1,600	-1,800
EBITDA (A-B)	7,500	7,800	8,100	8,400	8,700
Depreciation expenses	-2,000	-2,000	-2,000	-2,000	-2,000
EBIT	5,500	5,800	6,100	6,400	6,700
Interest expenses	-500	-400	-300	-200	-100

EBT	5,000	5,400	5,800	6,200	6,600
Income tax expense	-1,500	-1,620	-1,740	-1,860	-1,980
EAT	3,500	3,780	4,060	4,340	4,620

2.5 Impact of taxes on cash flows

As can be seen from the above example taxes impact returns. The net impact of taxes on returns again can be assessed using the net present value concept. This is illustrated using the previous example.

Example 33: Assessing impact of taxes on NPV of cash flows

Year	Discount factor (10%) (a) (Appendix 6)	Cash Flow after Taxes (b) (EAT)	Net Present Value after Taxes (a*b)	Cash Flow before Taxes (c) (EBT)	Net Present Value before Taxes (a*c)
0	1.000	-10,000	-10,000	-10,000	-10,000
1	0.909	3,500	3,182	5,000	4,545
2	0.826	3,780	3,124	5,400	4,463
3	0.751	4,060	3,050	5,800	4,358
4	0.683	4,340	2,964	6,200	4,235
5	0.621	4,620	2,869	6,600	4,098
NPV= 5,189			NPV= 11,699		

It can be seen that payable taxes have a considerable effect on the profitability of the project. In practice, the assessment of investment opportunities must be made after due consideration of income tax expenses.

2.6 Impact of Different Depreciation Methods and taxation on Cash flows

The type of depreciation method has a considerable impact on the resulting profitability of a project as well. Example 16 compares the Cash Flow after Taxes by using straight-line depreciation with the Cash Flow after Taxes by using reducing-balance (see Example 11). Due to the higher depreciation expenses in the earlier periods, the respective payable taxes are reduced and the first actual cash returns are increased by the latter method. Thus, because of the time value of money, the

project would be more profitable with reducing-balance depreciation. As a consequence, besides considering taxes, presented possible tax investment incentives have to be investigated.

Example 34: Impact of depreciation and income taxes on NPV of cash flows.

Year	Discount factor (10%) (a)	Cash Flow after Taxes (straight-line) (b)	Net Present Value after Taxes (a*b)	Cash Flow after Taxes (Reducing-balance) (c)	Net Present Value after Taxes (a*c)
0	1.000	-10,000	-10,000	-10,000	-10,000
1	0.909	3,500	3,182	3,800	3,455
2	0.826	3,780	3,124	3,810	3,149
3	0.751	4,060	3,050	3,950	2,968
4	0.683	4,340	2,964	4,230	2,889
5	0.621	4,620	2,869	4,510	2,800
NPV= 5,189			NPV= 5,260		

3. Financing Options

Most high budget projects involve seeking external finances while smaller projects can be funded by internal revenues. While financial viability assessments methods remain the same for both external financing agencies may scrutinize the project more deeply to assess the viability. Also, external financing agencies may conduct deeper sensitivity analysis to assess risks before funding. The higher the risk normally the charges for financing will be higher. Also, as per the mandate of the financing agencies they may fund projects preferentially (Eg: Government supported or credit guaranteed projects may get preference). High risk projects may not be financed by banks but by venture funds who look for higher returns. A project proponent needs to be aware of these aspects and may include financing agencies likely to fund the proposed project in their proposals.

The various options for financing energy management projects.

For projects requiring external funding

- By obtaining a bank loan

- By raising money from stock market
- By awarding the project to Energy Service Company(ESCO)

For projects funded from internal resources:

- From a central budget
- From a specific departmental or section budget such as engineering
- By retaining a proportion of the savings achieved.

While procedures for seeking funding from banks as loans or from stock markets as equity are well established ESCOs and performance contracting have emerged as new tools that reduces the risks of considering an energy efficiency or conservation project. Hence, implementing energy saving projects using ESCOs and performance contracting methods are only considered.

3.1 Energy Performance Contracting and Role of ESCOS

If the project is to be financed externally, one of the attractive options for many organizations is the use of energy performance contracts delivered by energy service companies, or ESCOs.

ESCOs are usually companies that provide a complete energy project service, from assessment to design to construction or installation, along with engineering and project management services, and financing. In one way or another, the contract involves the capitalization of all of the services and goods purchased, and repayment out of the energy savings that result from the project.

In performance contracting, an end-user (such as an industry, institution, or utility), seeking to improve its energy efficiency, contracts with ESCO for energy efficiency services and financing.

In some contracts, the ESCOs provide a guarantee for the savings that will be realized, and absorbs the cost if real savings fall short of this level. Typically, there will be a risk management cost involved in the contract in these situations. Insurance is sometimes attached, at a cost, to protect the ESCO in the event of savings shortfall.

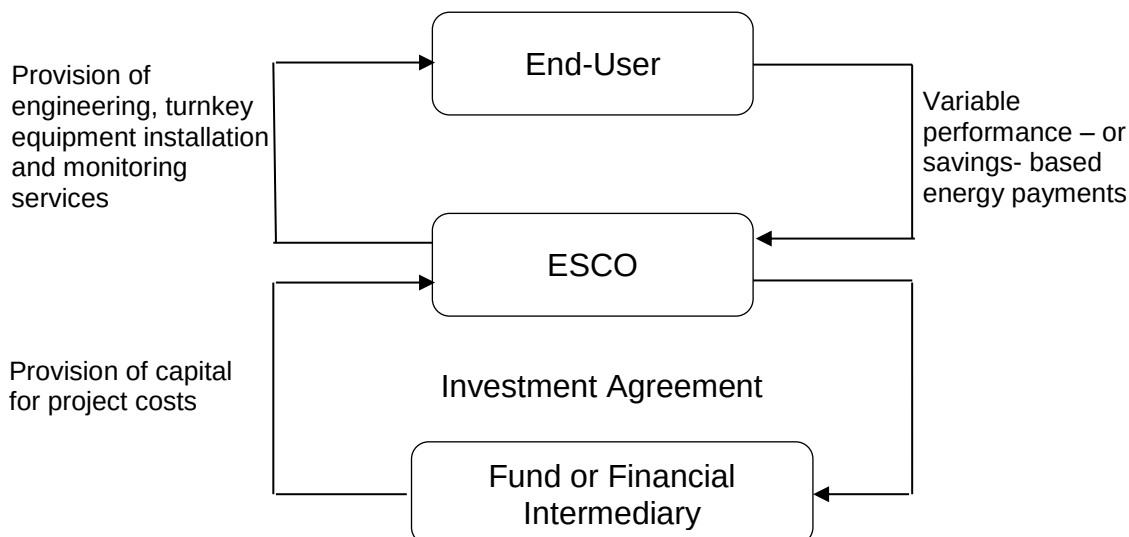
Energy efficiency projects generate incremental cost savings as opposed to incremental revenues from the sale of outputs. The energy cost savings can be turned into incremental cash flows to the lender or ESCO based on the commitment of the energy user (and in some cases, a utility) to pay for the savings.

3.1.1 What are performance contracts?

Performance contracting represents one of the ways to address several of the most

frequently mentioned barriers to investment. Performance contracting through an ESCO transfers the technology and management risks away from the end-user to the ESCO.

For energy users reluctant to invest in energy efficiency, a performance contract can be a powerful incentive to implement a project. Performance contracting also minimizes or eliminates the up-front cash outlay required by the end-user. Payments are made over time as the energy savings are realized.



What is Performance Contracting?

The core of performance contracting is an agreement involving a comprehensive package of services provided by an ESCO, including:

- An energy efficiency opportunity analysis
- Project development
- Engineering
- Financing
- Construction/ Implementation
- Training
- Monitoring and Verification

Monitoring and verification, is key to the successful involvement of an ESCO in performance contracting where energy cost savings are being guaranteed.

ESCOs are not “bankers” in the narrow sense. Their strength is in putting together a package of services that can provide guaranteed and measurable energy savings that serve as the basis for guaranteed cost savings. But, the energy savings must be measurable. Figure above shows ESCO role.

3.2 Self-Financing Energy Management

Large and capital intensive energy savings project funding or implementation are considered based on external financing smaller or easily implementable projects are considered by internal teams. To sustain continuous improvement the teams need to be encouraged and funding mechanism for systematically assessed viable projects needs to be created.

One way to make energy management self-financing is to split savings to provide identifiable returns to each interested party. This has the following benefits:

- Assigning a proportion of energy savings to your energy management budget means you have a direct financial incentive to identify and quantify savings arising from your own activities.
- Separately identified returns will help the constituent parts of your organization understanding whether they are each getting good value for money through their support for energy management.
- If operated successfully, splitting the savings will improve motivation and commitment to energy management throughout the organization since staff at all levels will see a financial return for their effort or support.
- But the main benefit is on the independence and longevity of the energy management function.

3.3 Ensuring Continuity

After implementation of energy savings, your organization ought to be able to make considerable savings at little cost (except for the funding needed for energy management staff). The important question is what should happen to these savings?

If part of these easily achieved savings is not returned to your budget as energy manager, then your access to self-generated investments funds to support future activities will be lost. And later in the program, it is likely to be much harder for you to make savings.

However, if, an energy manager has access to a proportion of the revenue savings arising from staff's activities, then these can be reinvested in:

- Further energy efficiency measures
- Activities necessary to create the right climate for successful energy management which do not, of themselves, directly generate savings
- Maintaining or up-grading the management information system.

APPENDIX 1: Present Value Tables

Discount factors: Present value of BDT1 to be received after t years = $1/(1 + r)^t$.

Number of Years	Interest Rate per Year														
	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
1	.990	.980	.971	.962	.952	.943	.935	.926	.917	.909	.901	.893	.885	.877	.870
2	.980	.961	.943	.925	.907	.890	.873	.857	.842	.826	.812	.797	.783	.769	.756
3	.971	.942	.915	.889	.864	.840	.816	.794	.772	.751	.731	.712	.693	.675	.658
4	.961	.924	.888	.855	.823	.792	.763	.735	.708	.683	.659	.636	.613	.592	.572
5	.951	.906	.863	.822	.784	.747	.713	.681	.650	.621	.593	.567	.543	.519	.497
6	.942	.888	.837	.790	.746	.705	.666	.630	.596	.564	.535	.507	.480	.456	.432
7	.933	.871	.813	.760	.711	.665	.623	.583	.547	.513	.482	.452	.425	.400	.376
8	.923	.853	.789	.731	.677	.627	.582	.540	.502	.467	.434	.404	.376	.351	.327
9	.914	.837	.766	.703	.645	.592	.544	.500	.460	.424	.391	.361	.333	.308	.284
10	.905	.820	.744	.676	.614	.558	.508	.463	.422	.386	.352	.322	.295	.270	.247
11	.896	.804	.722	.650	.585	.527	.475	.429	.388	.350	.317	.287	.261	.237	.215
12	.887	.788	.701	.625	.557	.497	.444	.397	.356	.319	.286	.257	.231	.208	.187
13	.879	.773	.681	.601	.530	.469	.415	.368	.326	.290	.258	.229	.204	.182	.163
14	.870	.758	.661	.577	.505	.442	.388	.340	.299	.263	.232	.205	.181	.160	.141
15	.861	.743	.642	.555	.481	.417	.362	.315	.275	.239	.209	.183	.160	.140	.123
16	.853	.728	.623	.534	.458	.394	.339	.292	.252	.218	.188	.163	.141	.123	.107
17	.844	.714	.605	.513	.436	.371	.317	.270	.231	.198	.170	.146	.125	.108	.093
18	.836	.700	.587	.494	.416	.350	.296	.250	.212	.180	.153	.130	.111	.095	.081
19	.828	.686	.570	.475	.396	.331	.277	.232	.194	.164	.138	.116	.098	.083	.070
20	.820	.673	.554	.456	.377	.312	.258	.215	.178	.149	.124	.104	.087	.073	.061

Number of Years	Interest Rate perYear														
	16%	17%	18%	19%	20%	21%	22%	23%	24%	25%	26%	27%	28%	29%	30%
1	.862	.855	.847	.840	.833	.826	.820	.813	.806	.800	.794	.787	.781	.775	.769
2	.743	.731	.718	.706	.694	.683	.672	.661	.650	.640	.630	.620	.610	.601	.592
3	.641	.624	.609	.593	.579	.564	.551	.537	.524	.512	.500	.488	.477	.466	.455
4	.552	.534	.516	.499	.482	.467	.451	.437	.423	.410	.397	.384	.373	.361	.350
5	.476	.456	.437	.419	.402	.386	.370	.355	.341	.328	.315	.303	.291	.280	.269
6	.410	.390	.370	.352	.335	.319	.303	.289	.275	.262	.250	.238	.227	.217	.207
7	.354	.333	.314	.296	.279	.263	.249	.235	.222	.210	.198	.188	.178	.168	.159
8	.305	.285	.266	.249	.233	.218	.204	.191	.179	.168	.157	.148	.139	.130	.123
9	.263	.243	.225	.209	.194	.180	.167	.155	.144	.134	.125	.116	.108	.101	.094
10	.227	.208	.191	.176	.162	.149	.137	.126	.116	.107	.099	.092	.085	.078	.073
11	.195	.178	.162	.148	.135	.123	.112	.103	.094	.086	.079	.072	.066	.061	.056
12	.168	.152	.137	.124	.112	.102	.092	.083	.076	.069	.062	.057	.052	.047	.043
13	.145	.130	.116	.104	.093	.084	.075	.068	.061	.055	.050	.045	.040	.037	.033
14	.125	.111	.099	.088	.078	.069	.062	.055	.049	.044	.039	.035	.032	.028	.025
15	.108	.095	.084	.074	.065	.057	.051	.045	.040	.035	.031	.028	.025	.022	.020
16	.093	.081	.071	.062	.054	.047	.042	.036	.032	.028	.025	.022	.019	.017	.015
17	.080	.069	.060	.052	.045	.039	.034	.030	.026	.023	.020	.017	.015	.013	.012
18	.069	.059	.051	.044	.038	.032	.028	.024	.021	.018	.016	.014	.012	.010	.009
19	.060	.051	.043	.037	.031	.027	.023	.020	.017	.014	.012	.011	.009	.008	.007
20	.051	.043	.037	.031	.026	.022	.019	.016	.014	.012	.010	.008	.007	.006	.005

Note: For example, if the interest rate is 10% per year, the present value of BDT1 received at year 5 is BDT.621.

APPENDIX 2: Future Value Tables

Future value of BDT1 after t years = $(1 + r)^t$.

Number of Years	Interest Rate per Year														
	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
1	1.010	1.020	1.030	1.040	1.050	1.060	1.070	1.080	1.090	1.100	1.110	1.120	1.130	1.140	1.150
2	1.020	1.040	1.061	1.082	1.102	1.124	1.145	1.166	1.188	1.210	1.232	1.254	1.277	1.300	1.323
3	1.030	1.061	1.093	1.125	1.158	1.191	1.225	1.260	1.295	1.331	1.368	1.405	1.443	1.482	1.521
4	1.041	1.082	1.126	1.170	1.216	1.262	1.311	1.360	1.412	1.464	1.518	1.574	1.630	1.689	1.749
5	1.051	1.104	1.159	1.217	1.276	1.338	1.403	1.469	1.539	1.611	1.685	1.762	1.842	1.925	2.011
6	1.062	1.126	1.194	1.265	1.340	1.419	1.501	1.587	1.677	1.772	1.870	1.974	2.082	2.195	2.313
7	1.072	1.149	1.230	1.316	1.407	1.504	1.606	1.714	1.828	1.949	2.076	2.211	2.353	2.502	2.660
8	1.083	1.172	1.267	1.369	1.477	1.594	1.718	1.851	1.993	2.144	2.305	2.476	2.658	2.853	3.059
9	1.094	1.195	1.305	1.423	1.551	1.689	1.838	1.999	2.172	2.358	2.558	2.773	3.004	3.252	3.518
10	1.105	1.219	1.344	1.480	1.629	1.791	1.967	2.159	2.367	2.594	2.839	3.106	3.395	3.707	4.046
11	1.116	1.243	1.384	1.539	1.710	1.898	2.105	2.332	2.580	2.853	3.152	3.479	3.836	4.226	4.652
12	1.127	1.268	1.426	1.601	1.796	2.012	2.252	2.518	2.813	3.138	3.498	3.896	4.335	4.818	5.350
13	1.138	1.294	1.469	1.665	1.886	2.133	2.410	2.720	3.066	3.452	3.883	4.363	4.898	5.492	6.153
14	1.149	1.319	1.513	1.732	1.980	2.261	2.579	2.937	3.342	3.797	4.310	4.887	5.535	6.261	7.076
15	1.161	1.346	1.558	1.801	2.079	2.397	2.759	3.172	3.642	4.177	4.785	5.474	6.254	7.138	8.137
16	1.173	1.373	1.605	1.873	2.183	2.540	2.952	3.426	3.970	4.595	5.311	6.130	7.067	8.137	9.358
17	1.184	1.400	1.653	1.948	2.292	2.693	3.159	3.700	4.328	5.054	5.895	6.866	7.986	9.276	10.76
18	1.196	1.428	1.702	2.026	2.407	2.854	3.380	3.996	4.717	5.560	6.544	7.690	9.024	10.58	12.38
19	1.208	1.457	1.754	2.107	2.527	3.026	3.617	4.316	5.142	6.116	7.263	8.613	10.20	12.06	14.23
20	1.220	1.486	1.806	2.191	2.653	3.207	3.870	4.661	5.604	6.727	8.062	9.646	11.52	13.74	16.37

Number of Years	Interest Rate per Year														
	16%	17%	18%	19%	20%	21%	22%	23%	24%	25%	26%	27%	28%	29%	30%
1	1.160	1.170	1.180	1.190	1.200	1.210	1.220	1.230	1.240	1.250	1.260	1.270	1.280	1.290	1.300
2	1.346	1.369	1.392	1.416	1.440	1.464	1.488	1.513	1.538	1.563	1.588	1.613	1.638	1.664	1.690
3	1.561	1.602	1.643	1.685	1.728	1.772	1.816	1.861	1.907	1.953	2.000	2.048	2.097	2.147	2.197
4	1.811	1.874	1.939	2.005	2.074	2.144	2.215	2.289	2.364	2.441	2.520	2.601	2.684	2.769	2.856
5	2.100	2.192	2.288	2.386	2.488	2.594	2.703	2.815	2.932	3.052	3.176	3.304	3.436	3.572	3.713
6	2.436	2.565	2.700	2.840	2.986	3.138	3.297	3.463	3.635	3.815	4.002	4.196	4.398	4.608	4.827
7	2.826	3.001	3.185	3.379	3.583	3.797	4.023	4.259	4.508	4.768	5.042	5.329	5.629	5.945	6.275
8	3.278	3.511	3.759	4.021	4.300	4.595	4.908	5.239	5.590	5.960	6.353	6.768	7.206	7.669	8.157
9	3.803	4.108	4.435	4.785	5.160	5.560	5.987	6.444	6.931	7.451	8.005	8.595	9.223	9.893	10.60
10	4.411	4.807	5.234	5.695	6.192	6.728	7.305	7.926	8.594	9.313	10.09	10.92	11.81	12.76	13.79
11	5.117	5.624	6.176	6.777	7.430	8.140	8.912	9.749	10.66	11.64	12.71	13.86	15.11	16.46	17.92
12	5.936	6.580	7.288	8.064	8.916	9.850	10.87	11.99	13.21	14.55	16.01	17.61	19.34	21.24	23.30
13	6.886	7.699	8.599	9.596	10.70	11.92	13.26	14.75	16.39	18.19	20.18	22.36	24.76	27.39	30.29
14	7.988	9.007	10.15	11.42	12.84	14.42	16.18	18.14	20.32	22.74	25.42	28.40	31.69	35.34	39.37
15	9.266	10.54	11.97	13.59	15.41	17.45	19.74	22.31	25.20	28.42	32.03	36.06	40.56	45.59	51.19
16	10.75	12.33	14.13	16.17	18.49	21.11	24.09	27.45	31.24	35.53	40.36	45.80	51.92	58.81	66.54
17	12.47	14.43	16.67	19.24	22.19	25.55	29.38	33.76	38.74	44.41	50.85	58.17	66.46	75.86	86.50
18	14.46	16.88	19.67	22.90	26.62	30.91	35.85	41.52	48.04	55.51	64.07	73.87	85.07	97.86	112.5
19	16.78	19.75	23.21	27.25	31.95	37.40	43.74	51.07	59.57	69.39	80.73	93.81	108.9	126.2	146.2
20	19.46	23.11	27.39	32.43	38.34	45.26	53.36	62.82	73.86	86.74	101.7	119.1	139.4	162.9	190.0

Note: For example, if the interest rate is 10% per year, the investment of BDT1 today will be worth BDT1.611 at year 5.

APPENDIX 3: Present Value Annuity Tables

Annuity table: Present value of BDT1 per year for each of t years = $1/r - 1/[r(1 + r)^t]$.

Number of Years	Interest Rate per Year														
	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
1	.990	.980	.971	.962	.952	.943	.935	.926	.917	.909	.901	.893	.885	.877	.870
2	1.970	1.942	1.913	1.886	1.859	1.833	1.808	1.783	1.759	1.736	1.713	1.690	1.668	1.647	1.626
3	2.941	2.884	2.829	2.775	2.723	2.673	2.624	2.577	2.531	2.487	2.444	2.402	2.361	2.322	2.283
4	3.902	3.808	3.717	3.630	3.546	3.465	3.387	3.312	3.240	3.170	3.102	3.037	2.974	2.914	2.855
5	4.853	4.713	4.580	4.452	4.329	4.212	4.100	3.993	3.890	3.791	3.696	3.605	3.517	3.433	3.352
6	5.795	5.601	5.417	5.242	5.076	4.917	4.767	4.623	4.486	4.355	4.231	4.111	3.998	3.889	3.784
7	6.728	6.472	6.230	6.002	5.786	5.582	5.389	5.206	5.033	4.868	4.712	4.564	4.423	4.288	4.160
8	7.652	7.325	7.020	6.733	6.463	6.210	5.971	5.747	5.535	5.335	5.146	4.968	4.799	4.639	4.487
9	8.566	8.162	7.786	7.435	7.108	6.802	6.515	6.247	5.995	5.759	5.537	5.328	5.132	4.946	4.772
10	9.471	8.983	8.530	8.111	7.722	7.360	7.024	6.710	6.418	6.145	5.889	5.650	5.426	5.216	5.019
11	10.37	9.787	9.253	8.760	8.306	7.887	7.499	7.139	6.805	6.495	6.207	5.938	5.687	5.453	5.234
12	11.26	10.58	9.954	9.385	8.863	8.384	7.943	7.536	7.161	6.814	6.492	6.194	5.918	5.660	5.421
13	12.13	11.35	10.63	9.986	9.394	8.853	8.358	7.904	7.487	7.103	6.750	6.424	6.122	5.842	5.583
14	13.00	12.11	11.30	10.56	9.899	9.295	8.745	8.244	7.786	7.367	6.982	6.628	6.302	6.002	5.724
15	13.87	12.85	11.94	11.12	10.38	9.712	9.108	8.559	8.061	7.606	7.191	6.811	6.462	6.142	5.847
16	14.72	13.58	12.56	11.65	10.84	10.11	9.447	8.851	8.313	7.824	7.379	6.974	6.604	6.265	5.954
17	15.56	14.29	13.17	12.17	11.27	10.48	9.763	9.122	8.544	8.022	7.549	7.120	6.729	6.373	6.047
18	16.40	14.99	13.75	12.66	11.69	10.83	10.06	9.372	8.756	8.201	7.702	7.250	6.840	6.467	6.128
19	17.23	15.68	14.32	13.13	12.09	11.16	10.34	9.604	8.950	8.365	7.839	7.366	6.938	6.550	6.198
20	18.05	16.35	14.88	13.59	12.46	11.47	10.59	9.818	9.129	8.514	7.963	7.469	7.025	6.623	6.259

Number of Years	Interest Rate per Year														
	16%	17%	18%	19%	20%	21%	22%	23%	24%	25%	26%	27%	28%	29%	30%
1	.862	.855	.847	.840	.833	.826	.820	.813	.806	.800	.794	.787	.781	.775	.769
2	1.605	1.585	1.566	1.547	1.528	1.509	1.492	1.474	1.457	1.440	1.424	1.407	1.392	1.376	1.361
3	2.246	2.210	2.174	2.140	2.106	2.074	2.042	2.011	1.981	1.952	1.923	1.896	1.868	1.842	1.816
4	2.798	2.743	2.690	2.639	2.589	2.540	2.494	2.448	2.404	2.362	2.320	2.280	2.241	2.203	2.166
5	3.274	3.199	3.127	3.058	2.991	2.926	2.864	2.803	2.745	2.689	2.635	2.583	2.532	2.483	2.436
6	3.685	3.589	3.498	3.410	3.326	3.245	3.167	3.092	3.020	2.951	2.885	2.821	2.759	2.700	2.643
7	4.039	3.922	3.812	3.706	3.605	3.508	3.416	3.327	3.242	3.161	3.083	3.009	2.937	2.868	2.802
8	4.344	4.207	4.078	3.954	3.837	3.726	3.619	3.518	3.421	3.329	3.241	3.156	3.076	2.999	2.925
9	4.607	4.451	4.303	4.163	4.031	3.905	3.786	3.673	3.566	3.463	3.366	3.273	3.184	3.100	3.019
10	4.833	4.659	4.494	4.339	4.192	4.054	3.923	3.799	3.682	3.571	3.465	3.364	3.269	3.178	3.092
11	5.029	4.836	4.656	4.486	4.327	4.177	4.035	3.902	3.776	3.656	3.543	3.437	3.335	3.239	3.147
12	5.197	4.988	4.793	4.611	4.439	4.278	4.127	3.985	3.851	3.725	3.606	3.493	3.387	3.286	3.190
13	5.342	5.118	4.910	4.715	4.533	4.362	4.203	4.053	3.912	3.780	3.656	3.538	3.427	3.322	3.223
14	5.468	5.229	5.008	4.802	4.611	4.432	4.265	4.108	3.962	3.824	3.695	3.573	3.459	3.351	3.249
15	5.575	5.324	5.092	4.876	4.675	4.489	4.315	4.153	4.001	3.859	3.726	3.601	3.483	3.373	3.268
16	5.668	5.405	5.162	4.938	4.730	4.536	4.357	4.189	4.033	3.887	3.751	3.623	3.503	3.390	3.283
17	5.749	5.475	5.222	4.990	4.775	4.576	4.391	4.219	4.059	3.910	3.771	3.640	3.518	3.403	3.295
18	5.818	5.534	5.273	5.033	4.812	4.608	4.419	4.243	4.080	3.928	3.786	3.654	3.529	3.413	3.304
19	5.877	5.584	5.316	5.070	4.843	4.635	4.442	4.263	4.097	3.942	3.799	3.664	3.539	3.421	3.311
20	5.929	5.628	5.353	5.101	4.870	4.657	4.460	4.279	4.110	3.954	3.808	3.673	3.546	3.427	3.316

Note: For example, if the interest rate is 10% per year, the investment of BDT1 received in each of the next 5 years is BDT3.791.

APPENDIX 4: Future Value Annuity Tables

Values of e^{rt} . Future value of BDT1 invested at a *continuously compounded* rate r for t years.

rt	.00	.01	.02	.03	.04	.05	.06	.07	.08	.09
.00	1.000	1.010	1.020	1.030	1.041	1.051	1.062	1.073	1.083	1.094
.10	1.105	1.116	1.127	1.139	1.150	1.162	1.174	1.185	1.197	1.209
.20	1.221	1.234	1.246	1.259	1.271	1.284	1.297	1.310	1.323	1.336
.30	1.350	1.363	1.377	1.391	1.405	1.419	1.433	1.448	1.462	1.477
.40	1.492	1.507	1.522	1.537	1.553	1.568	1.584	1.600	1.616	1.632
.50	1.649	1.665	1.682	1.699	1.716	1.733	1.751	1.768	1.786	1.804
.60	1.822	1.840	1.859	1.878	1.896	1.916	1.935	1.954	1.974	1.994
.70	2.014	2.034	2.054	2.075	2.096	2.117	2.138	2.160	2.181	2.203
.80	2.226	2.248	2.271	2.293	2.316	2.340	2.363	2.387	2.411	2.435
.90	2.460	2.484	2.509	2.535	2.560	2.586	2.612	2.638	2.664	2.691
1.00	2.718	2.746	2.773	2.801	2.829	2.858	2.886	2.915	2.945	2.974
1.10	3.004	3.034	3.065	3.096	3.127	3.158	3.190	3.222	3.254	3.287
1.20	3.320	3.353	3.387	3.421	3.456	3.490	3.525	3.561	3.597	3.633
1.30	3.669	3.706	3.743	3.781	3.819	3.857	3.896	3.935	3.975	4.015
1.40	4.055	4.096	4.137	4.179	4.221	4.263	4.306	4.349	4.393	4.437
1.50	4.482	4.527	4.572	4.618	4.665	4.711	4.759	4.807	4.855	4.904
1.60	4.953	5.003	5.053	5.104	5.155	5.207	5.259	5.312	5.366	5.419
1.70	5.474	5.529	5.585	5.641	5.697	5.755	5.812	5.871	5.930	5.989
1.80	6.050	6.110	6.172	6.234	6.297	6.360	6.424	6.488	6.553	6.619
1.90	6.686	6.753	6.821	6.890	6.959	7.029	7.099	7.171	7.243	7.316
2.00	7.389	7.463	7.538	7.614	7.691	7.768	7.846	7.925	8.004	8.085
2.10	8.166	8.248	8.331	8.415	8.499	8.585	8.671	8.758	8.846	8.935
2.20	9.025	9.116	9.207	9.300	9.393	9.488	9.583	9.679	9.777	9.875
2.30	9.974	10.07	10.18	10.28	10.38	10.49	10.59	10.70	10.80	10.91
2.40	11.02	11.13	11.25	11.36	11.47	11.59	11.70	11.82	11.94	12.06
2.50	12.18	12.30	12.43	12.55	12.68	12.81	12.94	13.07	13.20	13.33
2.60	13.46	13.60	13.74	13.87	14.01	14.15	14.30	14.44	14.59	14.73
2.70	14.88	15.03	15.18	15.33	15.49	15.64	15.80	15.96	16.12	16.28
2.80	16.44	16.61	16.78	16.95	17.12	17.29	17.46	17.64	17.81	17.99
2.90	18.17	18.36	18.54	18.73	18.92	19.11	19.30	19.49	19.69	19.89
3.00	20.09	20.29	20.49	20.70	20.91	21.12	21.33	21.54	21.76	21.98
3.10	22.20	22.42	22.65	22.87	23.10	23.34	23.57	23.81	24.05	24.29
3.20	24.53	24.78	25.03	25.28	25.53	25.79	26.05	26.31	26.58	26.84
3.30	27.11	27.39	27.66	27.94	28.22	28.50	28.79	29.08	29.37	29.67
3.40	29.96	30.27	30.57	30.88	31.19	31.50	31.82	32.14	32.46	32.79
3.50	33.12	33.45	33.78	34.12	34.47	34.81	35.16	35.52	35.87	36.23
3.60	36.60	36.97	37.34	37.71	38.09	38.47	38.86	39.25	39.65	40.04
3.70	40.45	40.85	41.26	41.68	42.10	42.52	42.95	43.38	43.82	44.26
3.80	44.70	45.15	45.60	46.06	46.53	46.99	47.47	47.94	48.42	48.91
3.90	49.40	49.90	50.40	50.91	51.42	51.94	52.46	52.98	53.52	54.05

Note: For example, if the continuously compounded interest rate is 10% per year, the investment of BDT1 today will be worth BDT1.105 at year 1 and BDT1.221 at year 2.

APPENDIX 5: Present Value Annuity Tables

Present value of BDT1 per year received in a continuous stream for each of t years (discounted at an annually compounded rate r) = $\{1 - 1/(1 + r)^t\}/\ln(1 + r)$.

Number of Years	Interest Rate per Year														
	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
1	.995	.990	.985	.981	.976	.971	.967	.962	.958	.954	.950	.945	.941	.937	.933
2	1.980	1.961	1.942	1.924	1.906	1.888	1.871	1.854	1.837	1.821	1.805	1.790	1.774	1.759	1.745
3	2.956	2.913	2.871	2.830	2.791	2.752	2.715	2.679	2.644	2.609	2.576	2.543	2.512	2.481	2.450
4	3.922	3.846	3.773	3.702	3.634	3.568	3.504	3.443	3.383	3.326	3.270	3.216	3.164	3.113	3.064
5	4.878	4.760	4.648	4.540	4.437	4.337	4.242	4.150	4.062	3.977	3.896	3.817	3.741	3.668	3.598
6	5.825	5.657	5.498	5.346	5.202	5.063	4.931	4.805	4.685	4.570	4.459	4.353	4.252	4.155	4.062
7	6.762	6.536	6.323	6.121	5.930	5.748	5.576	5.412	5.256	5.108	4.967	4.832	4.704	4.582	4.465
8	7.690	7.398	7.124	6.867	6.623	6.394	6.178	5.974	5.780	5.597	5.424	5.260	5.104	4.956	4.816
9	8.609	8.243	7.902	7.583	7.284	7.004	6.741	6.494	6.261	6.042	5.836	5.642	5.458	5.285	5.121
10	9.519	9.072	8.657	8.272	7.913	7.579	7.267	6.975	6.702	6.447	6.208	5.983	5.772	5.573	5.386
11	10.42	9.884	9.391	8.935	8.512	8.121	7.758	7.421	7.107	6.815	6.542	6.287	6.049	5.826	5.617
12	11.31	10.68	10.10	9.572	9.083	8.633	8.218	7.834	7.478	7.149	6.843	6.559	6.294	6.048	5.818
13	12.19	11.46	10.79	10.18	9.627	9.116	8.647	8.216	7.819	7.453	7.115	6.802	6.512	6.242	5.992
14	13.07	12.23	11.46	10.77	10.14	9.571	9.048	8.570	8.131	7.729	7.359	7.018	6.704	6.413	6.144
15	13.93	12.98	12.12	11.34	10.64	10.00	9.423	8.897	8.418	7.980	7.579	7.212	6.874	6.563	6.276
16	14.79	13.71	12.75	11.88	11.11	10.41	9.774	9.201	8.681	8.209	7.778	7.385	7.024	6.694	6.390
17	15.64	14.43	13.36	12.41	11.55	10.79	10.10	9.482	8.923	8.416	7.957	7.539	7.158	6.809	6.490
18	16.48	15.14	13.96	12.91	11.98	11.15	10.41	9.742	9.144	8.605	8.118	7.676	7.275	6.910	6.577
19	17.31	15.83	14.54	13.39	12.39	11.49	10.69	9.983	9.347	8.777	8.263	7.799	7.380	6.999	6.652
20	18.14	16.51	15.10	13.86	12.77	11.81	10.96	10.21	9.533	8.932	8.394	7.909	7.472	7.077	6.718

Number of Years	Interest Rate per Year														
	16%	17%	18%	19%	20%	21%	22%	23%	24%	25%	26%	27%	28%	29%	30%
1	.929	.925	.922	.918	.914	.910	.907	.903	.900	.896	.893	.889	.886	.883	.880
2	1.730	1.716	1.703	1.689	1.676	1.663	1.650	1.638	1.625	1.613	1.601	1.590	1.578	1.567	1.556
3	2.421	2.392	2.365	2.337	2.311	2.285	2.259	2.235	2.211	2.187	2.164	2.141	2.119	2.098	2.077
4	3.016	2.970	2.925	2.882	2.840	2.799	2.759	2.720	2.682	2.646	2.610	2.576	2.542	2.509	2.477
5	3.530	3.464	3.401	3.340	3.281	3.223	3.168	3.115	3.063	3.013	2.964	2.917	2.872	2.828	2.785
6	3.972	3.886	3.804	3.724	3.648	3.574	3.504	3.436	3.370	3.307	3.246	3.187	3.130	3.075	3.022
7	4.354	4.247	4.145	4.048	3.954	3.865	3.779	3.696	3.617	3.542	3.469	3.399	3.331	3.266	3.204
8	4.682	4.555	4.434	4.319	4.209	4.104	4.004	3.909	3.817	3.730	3.646	3.566	3.489	3.415	3.344
9	4.966	4.819	4.680	4.547	4.422	4.302	4.189	4.081	3.978	3.880	3.786	3.697	3.612	3.530	3.452
10	5.210	5.044	4.887	4.739	4.599	4.466	4.340	4.221	4.108	4.000	3.898	3.801	3.708	3.619	3.535
11	5.421	5.237	5.063	4.900	4.747	4.602	4.465	4.335	4.213	4.096	3.986	3.882	3.783	3.689	3.599
12	5.603	5.401	5.213	5.036	4.870	4.713	4.566	4.428	4.297	4.173	4.057	3.946	3.841	3.742	3.648
13	5.759	5.542	5.339	5.150	4.972	4.806	4.650	4.503	4.365	4.235	4.112	3.997	3.887	3.784	3.686
14	5.894	5.662	5.446	5.245	5.058	4.882	4.718	4.564	4.420	4.284	4.157	4.036	3.923	3.816	3.715
15	6.010	5.765	5.537	5.326	5.129	4.945	4.774	4.614	4.464	4.324	4.192	4.068	3.951	3.841	3.737
16	6.111	5.853	5.614	5.393	5.188	4.998	4.820	4.655	4.500	4.355	4.220	4.092	3.973	3.860	3.754
17	6.197	5.928	5.679	5.450	5.238	5.041	4.858	4.687	4.529	4.381	4.242	4.112	3.990	3.875	3.767
18	6.272	5.992	5.735	5.498	5.279	5.076	4.889	4.714	4.552	4.401	4.259	4.127	4.003	3.887	3.778
19	6.336	6.047	5.781	5.538	5.313	5.106	4.914	4.736	4.571	4.417	4.273	4.139	4.014	3.896	3.785
20	6.391	6.094	5.821	5.571	5.342	5.130	4.935	4.754	4.586	4.430	4.284	4.149	4.022	3.903	3.791

Note:Forexample, if the interest rate is 10% per year, a continuous cash flow of BDT1 a year for each of 5 years is worth BDT3.977. A continuous flow of BDT1 in year 5 only is worth BDT3.977 – BDT3.326 = BDT.651.

APPENDIX 6: Discount Factor Table

The following formula is used to calculate a discount factor for year t and imputed rate of interest i : $1/(1+i)^t$

Number of years (t)	Interest Rate per year										
	0%	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%
0	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
1	1.0000	0.9901	0.9804	0.9709	0.9615	0.9524	0.9434	0.9346	0.9259	0.9174	0.9091
2	1.0000	0.9803	0.9612	0.9426	0.9246	0.9070	0.8900	0.8734	0.8573	0.8417	0.8264
3	1.0000	0.9706	0.9423	0.9151	0.8890	0.8638	0.8396	0.8163	0.7938	0.7722	0.7513
4	1.0000	0.9610	0.9238	0.8885	0.8548	0.8227	0.7921	0.7629	0.7350	0.7084	0.6830
5	1.0000	0.9515	0.9057	0.8626	0.8219	0.7835	0.7473	0.7130	0.6806	0.6499	0.6209
6	1.0000	0.9420	0.8880	0.8375	0.7903	0.7462	0.7050	0.6663	0.6302	0.5963	0.5645
7	1.0000	0.9327	0.8706	0.8131	0.7599	0.7107	0.6651	0.6227	0.5835	0.5470	0.5132
8	1.0000	0.9235	0.8535	0.7894	0.7307	0.6768	0.6274	0.5820	0.5403	0.5019	0.4665
9	1.0000	0.9143	0.8368	0.7664	0.7026	0.6446	0.5919	0.5439	0.5002	0.4604	0.4241
10	1.0000	0.9053	0.8203	0.7441	0.6756	0.6139	0.5584	0.5083	0.4632	0.4224	0.3855

Module 5

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1. ENERGY MONITORING, TARGETING AND REPORTING

1.1 Introduction

Energy monitoring and targeting is primarily a management technique that uses energy information as a basis to eliminate waste, reduce and control current level of energy use and improve the existing operating procedures. It builds on the principle **"you can't manage what you don't measure"**. It essentially combines the principles of energy use and statistics.

Energy monitoring, target setting, and reporting (MT&R) is the activity which uses information on energy consumption as a basis for control and managing consumption. The three component activities are distinct yet inter-related:

1.2 What is Monitoring and Targeting?

Monitoring is the regular collection of information on energy use. Its purpose is to establish a basis of management control, to determine when and why energy consumption is deviating from an established pattern, and as a basis for taking management action where necessary. Monitoring is essentially aimed at sustaining an established pattern.

Effective monitoring involves regular collection of energy and related variable for example production, analysis of data and investigation of deviation from expected performance using some performance model.

Targeting or Target setting is the identification of levels of energy consumption, which is desirable.

Reporting involves "closing the loop" by putting the management information generated from the monitoring process in a form that enables ongoing control of energy use, the achievement of reduction targets, and the verification of savings.

It is putting information in a form that drives action to control energy use and achieve targets.

Monitoring and target setting have elements in common and they share much of the same information. As a general rule, however, monitoring comes before target setting because without monitoring you cannot know precisely where you are starting from, or decide if a target has been achieved. The reporting phase not only supports management control, but also provides for accountability in the relationship between performance and targets.

Monitoring and Targeting is a management technique in which all utilities such as fuel, steam, refrigeration, compressed air, water, effluent, and electricity are managed as

controllable resources in the same way that raw materials, finished product inventory are managed.

It involves a systematic, disciplined division of the facility into Energy Cost Centers. The utilities used in each center are closely monitored, and the energy used is compared with production volume or any other suitable measure of operation. Once this information is available on a regular basis, targets can be set, variances can be spotted and interpreted, and remedial actions can be taken and implemented.

The Monitoring and Targeting programs have been so effective that they show typical reductions in annual energy costs in various industrial sectors between 5 and 20%.

1.2 Need for Monitoring & Targeting

The energy used by any industry or facility varies as production processes, volumes, and inputs vary. Determining the relationship of energy use to key performance indicators will allow management to determine:

- Whether current energy use is better or worse than before;
- Trends in energy consumption that reflect seasonal, weekly, and other operating patterns;
- How much future energy use is likely to vary if some aspects of business change;
- Specific areas of wasted energy;
- Comparisons with other businesses with similar characteristics. This “benchmarking” process will provide valuable information of the effectiveness of operations as well as energy use;
- How business reacted to changes in the past;
- How to develop performance targets for an energy management program.

1.3 Elements of Monitoring & Targeting System

The essential elements of M&T system are:

Recording - Measuring and recording energy consumption

Analyzing - Correlating energy consumption to a measured output, such as production quantity.

Comparing-Comparing energy consumption to an appropriate standard or benchmark.

Setting Targets -Setting targets to reduce or control energy consumption.

Monitoring -Comparing energy consumption to the set target on a regular basis.

Reporting- Reporting the results including any variances from the set targets.

Controlling -Implementing management measures to correct any deviations, which may have occurred.

Particularly M&T system will involve the following:

- **Checking** the accuracy of energy invoices
- **Allocating** energy costs to specific departments (Energy Accounting Centers)
- **Determining** energy performance/efficiency
- **Recording** energy use, so that projects intended to improve energy efficiency can be checked
- **Highlighting** performance problems in equipment or systems

1.4 Structuring of a Monitoring System

The first and the most important step is the development of a measurement concept. Measuring points are defined for energy data acquisition. For accumulation of data, sensors are needed. The next step is the data processing and saving. This step contains the visualization and analyzing of the data. With the data processing, controlling system comes into action.

Figure 1.1 shows typical basic design of a standardized monitoring system. Inputs to the monitoring system are energy data and operational data. The outputs from the monitoring system are key figures, alarming for deviation system, reporting structure and the documentation.

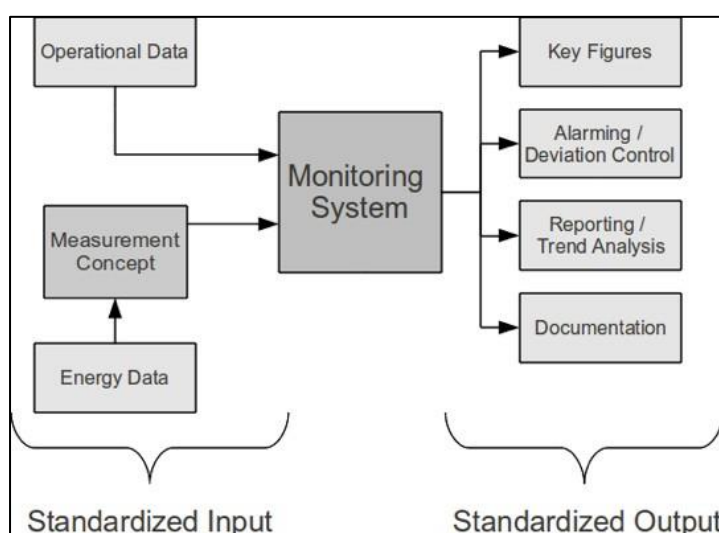


Figure 1.1: Work Flow for a Standardized Monitoring System

The design of the monitoring system will differ between companies. The basic elements must be later improved according to the individual needs of the companies as part of continual

improvement.

1.5 Requirements for System Configuration

Before system design, requirements should be defined. It must be decided what kind of data should be included in the monitoring system. Data such as energy flow by type and quantity, material flows describing input and output of the analyzed process as well as monetary flows are needed as reference parameters. Other information may include heated area, time, and number of employees or ambient temperature. The information includes raw data which requires interpretation or re-assessed information as the result of an analysis or calculation.

Consistency and reliability of the identified energy data flow should be ensured through appropriate measuring technology. The location of the sensors and periodicity of the data collection should be decided. A key point here is the measuring accuracy and sensor sensitivity. The possibility of reading errors because of manual readouts must be minimized. The metering precision should be ensured.

Information should be provided to the concerned person appropriately either in form of onsite display or centrally through data acquisition station. It must be also decided whether reports are sent to the receiver because of deviation (alarm) or at preset intervals (standard report) or both.

Another aspect to be considered is where and how fast the information has to be made available. The process owner is able to assess, interpret the data and act immediately. The person-in-charge must have information in time so that he or she can intervene where necessary. In some cases it might be advisable to inform the top management as well.

The elapsed time before an error in the run of process is detected or indicated as unusual behavior depends on process dynamics. Each process has arrange of normal behavior. Deviations out of this range can be temporary and self-regulating or they also might indicate need for immediate intervention.

The other influencing factors are measuring points. Some measured process-related parameters influence only the surrounding process. Other measurement points may require the measurement of additional parameters, for example, correlation of parameters like between pressure and temperature. These correlations can be uni- or bi directional. Intensity of connections can differ and a various amount of parameters can be affected.

Similar to this challenge is the inclusion of external influencing factors. Instead of resulting from a process itself they influence the system from the outside. Relevant impacts are all parameters that influence the course or the result of the considered process. This means that each system can have its own influencing factors. External influences are parameters like

climate conditions such as ambient temperature or air humidity.

1.6 Scope and Information for Monitoring, Targeting and Reporting

Information related to energy use may be obtained from following sources:

- Plant level information can be derived from financial accounting systems-utilities cost centre
- Plant department level information can be found in comparative energy consumption data for a group of similar facilities, service entrance meter readings etc.
- System level (for example, boiler plant) performance data can be determined from sub-metering data
- Equipment level information can be obtained from name plate data, run-time and schedule information, sub-metered data on specific energy consuming equipment.

All of these data are useful and can be processed to yield information about facility performance.

1.7 Data and Information Analysis

Within the activity of M &T, data and information are distinct entities. The activity of monitoring a facility, system or process involves both measurement and analysis. Data are raw numbers such as would be the result of a measurement. Information is the result of some type of analysis upon data.

Figure 1.2 illustrates the distinction between data and information for a production situation. In this case, energy consumption and production of a melting furnace are routinely measured and recorded.

What refines performance data into management information is the analysis. The Management information seeks questions about performance that would not be evident in the raw data, and can lead to actions for correction of problems or optimization of performance. The distinction between data and information is illustrated in the Figure 1.2.

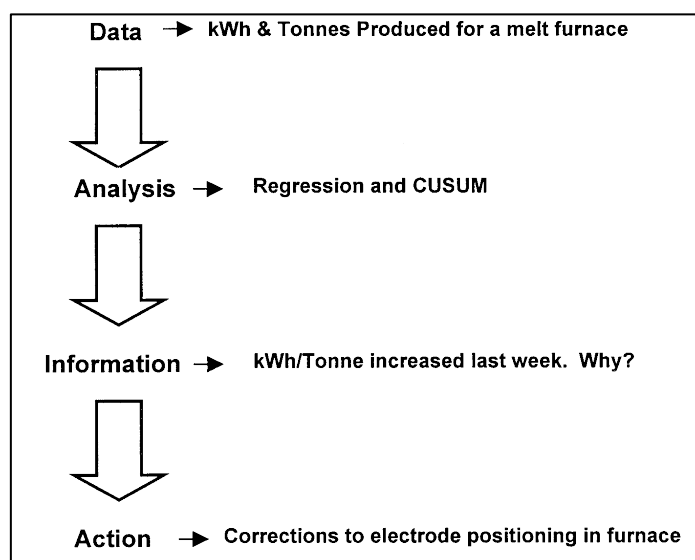


Figure 1.2: Example of Data and Information in Production System

The process illustrated in the Figure 1.1 is not linear. Corrections to electrode positioning in the furnace has to result in another cycle of monitoring and analysis to ensure that the change has been effective and is being sustained. New optimisation actions typically result, and so the cycle—measure-analyse-action—continues indefinitely, true to the intent of continuous improvement as shown in Figure 1.3.

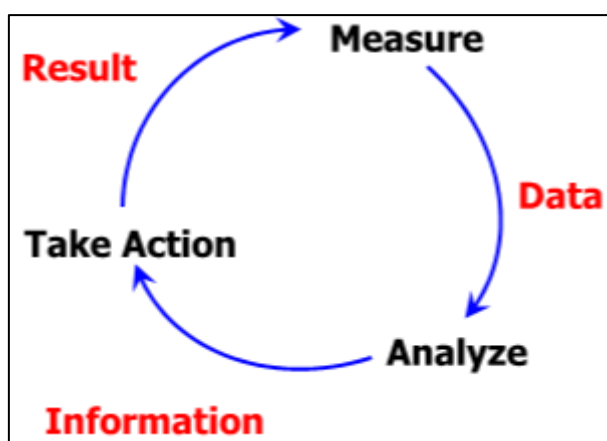


Figure 1.3: The Measure-Analyze-Action Cycle

Plant level information

Electricity bills and other fuel bills should be collected periodically and analysed as below. A typical format for monitoring plant level information is given below in the Table 1.1.

Table 1.1: Annual Energy Bill and Cost Month-wise

	Thermal Energy Bill				Electricity Bill				Total Energy Bill
Month					Day kWh	Night kWh	Maximum Demand kVA	Total	
1									
2									
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
Sub-Total									
%									

Pie Chart on Energy Consumption

After obtaining the respective annual energy cost, a pie chart (see Figure 1) can be drawn as a pie-chart as shown in Figure 1.4 for analysis.

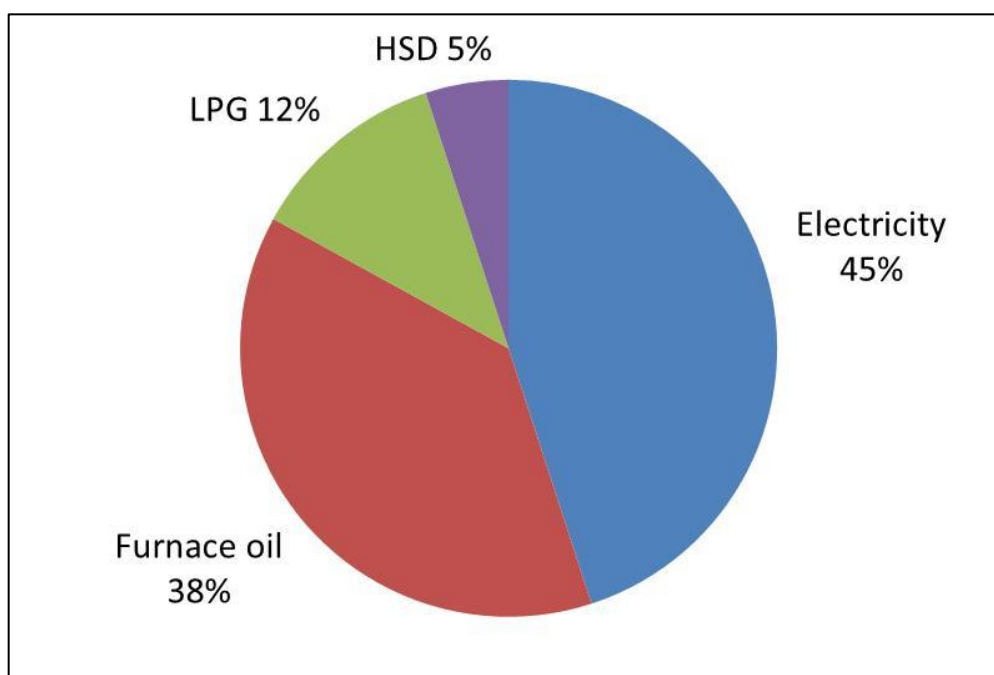


Figure 1.4: Share of Fuel Costs Based on Energy Bill

All the fuels purchased by the plant should be converted into common units such as kCal. The following Table 1.2 below can be used for fuel conversion into common units.

Table 1.2: Fuel Conversion Data

Energy source	Supply unit	Conversion Factor to Kcal
Electricity	kWh	860
HSD	kg	10,500
Furnace Oil	kg	10,200
LPG	kg	12,000

1.8 Relating Energy Consumption and Production

Graphing the Data

A critical feature of M&T is to understand what drives energy consumption. Is it production, hours of operation or weather? After identifying the driver, we can analyse the data to find out how good our energy management is.

After collection of energy consumption, energy cost and production data (driver in this

case), the next stage of the monitoring process is to study and analyse the data to understand what is happening in the plant. For this data is presented graphically.

A better appreciation of variations is always obtained from a visual presentation, rather than from a table of numbers. Graphs generally provide an effective means of developing the energy-production relationships, which explain what is going on in the plant.

Use of Bar Chart

The energy data normally entered and made available in a spreadsheet. Since, it is hard to envisage what is happening from the plain data in the spreadsheet, the data is presented using a bar chart. The starting point is to collect and collate 24 months of energy bills and present the monthly energy consumption for current year and the previous year side-by-side (Figure 1.5). However, this method is not useful; hence production data is also needed for the same 24 month period.

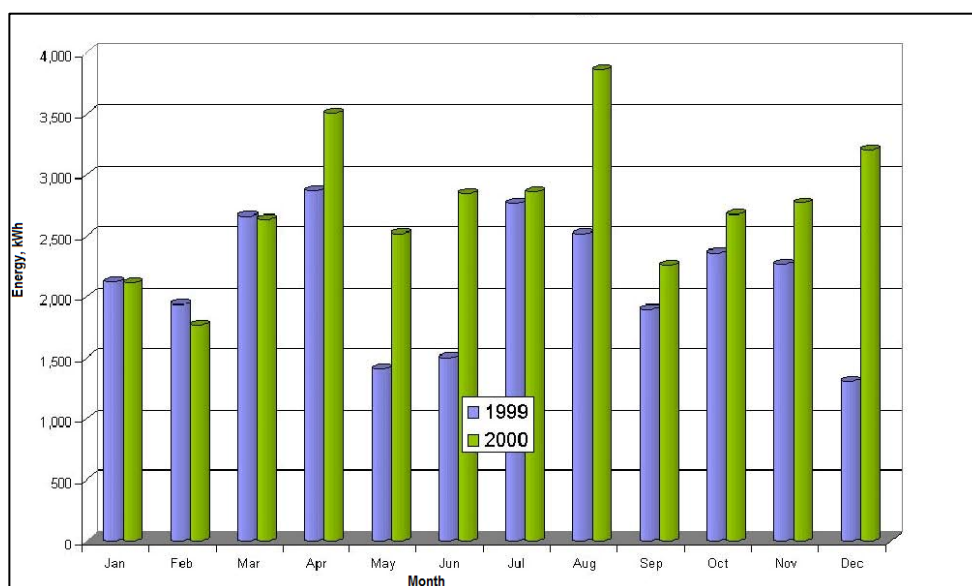


Figure 1.5: Bar Chart—Production for Current and Previous Years

Time-dependent Energy Analysis

If monthly energy consumption data is available, it is possible to produce a simple graph in which energy consumption is plotted against time (Figure 1.6). Time-dependent analysis enables us to identify general trends and seasonal patterns in energy consumption. Any exception to the norm is also identified immediately.

The limitations of this analysis are that it is difficult to find out why certain trends occur or if a particular trend is there or not. Although, this tool is useful, it can be used only as a comparative tool and not an absolute one.

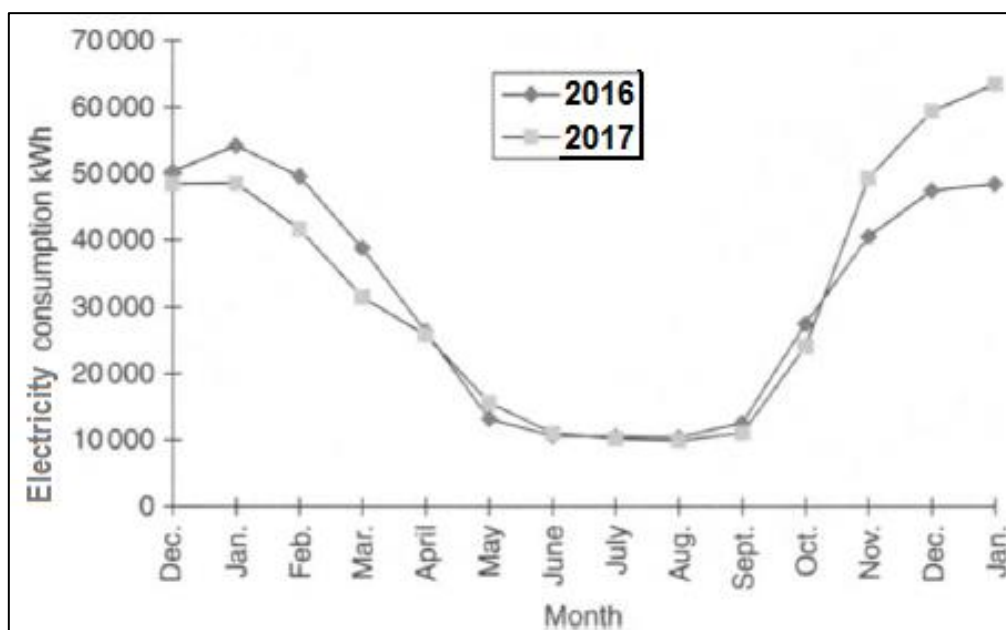


Figure 1.6: Monthly Electricity Consumption

From the time dependent graph shows monthly electricity consumption for the years 2016 and 2017 is shown, the following can be inferred:

- Electricity consumption during the months of January to March of 2017 is consistently lower than that of corresponding period of 2016.
- The base load electricity consumption is approximately 10,500 kWh/month.
- Energy consumption during the months of November and December 2016 and January 2017 had increased significantly compared with the corresponding 2016 figures indicating possible loss of control over electricity consumption.

However, it is not possible to identify why the energy consumption for January, February and March 2017 is lower than for the same period in 2016. For this, further analysis is needed.

It is also possible to plot more than one variable using this chart, for example, oil consumption along with electricity consumption data.

Norm Chart

The norm chart is a sequential plot of actual energy consumption overlaid on a plot of target consumption (Figure 1.7). It highlights exceptions which senior and operational manager can easily understand

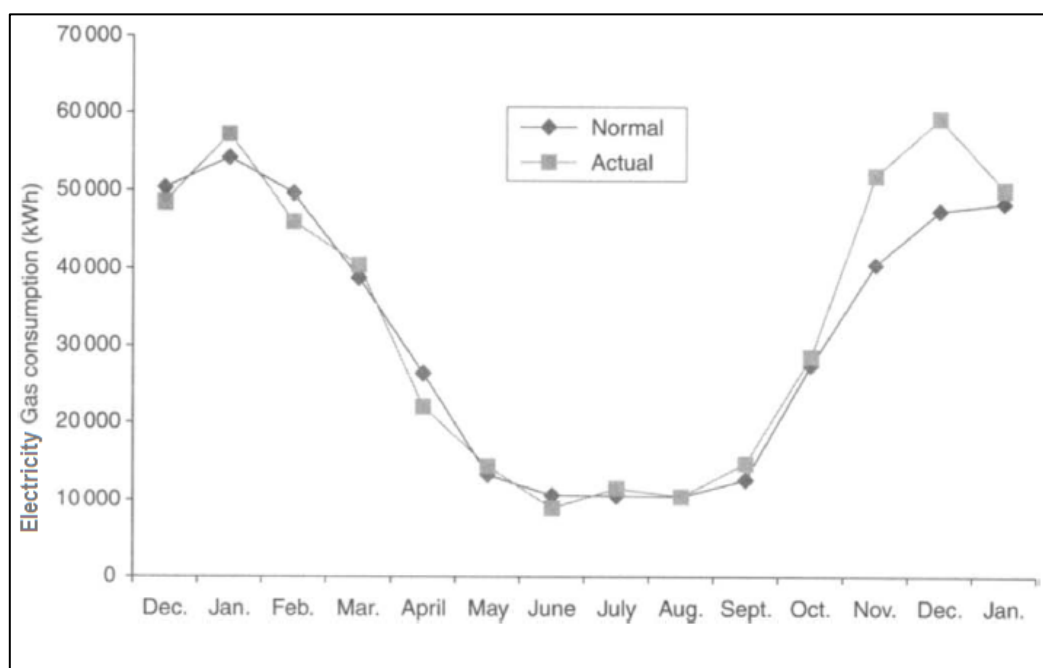


Figure 1.7: Norms Chart for Gas Consumption

Deviance Chart

The difference between target and actual energy consumption is plotted month wise (Figure 1.8). If for any month, energy consumption is above the target or predicted value, the consumption is plotted as a positive value; by contrast a negative value is returned if actual energy consumption is lower than predicted.

When producing a deviance chart it is useful to show on the graph limits of normal operation, since this helps to distinguish between normal limits and serious deviations from the norm. Deviance charts are most suited at highlighting problems so that remedial action can be taken. They can also be used to initiate detailed exception reports.

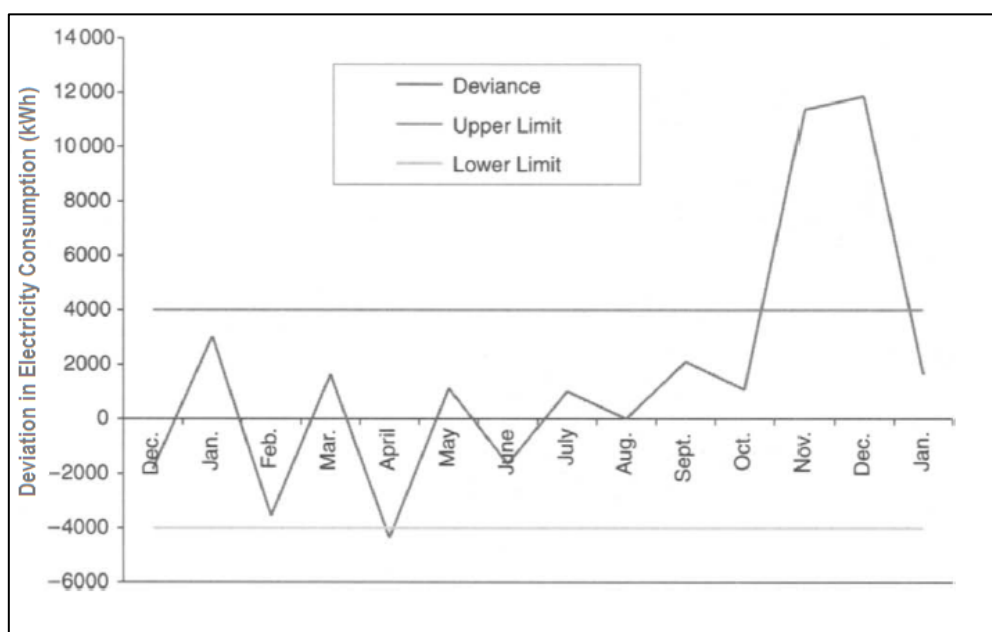


Figure 1.8: Deviance Chart for Gas Consumption

Moving Annual Total

If more than twelve months of production and energy data are available, moving annual total can be plotted. Each point in the chart represents the sum of the previous twelve months of data as shown in Figure 1.9. Each point covers a full range of the seasons, holidays, etc. In this way, this technique smoothen errors in the timings of meter readings.

This chart smoothen out errors in the timing of meter readings. If just energy reading is plotted, only a part of the story is conveyed. By plotting energy and production on the same chart-using two y-axes, both energy and productions normally track each other. This suggests no cause for alarm.

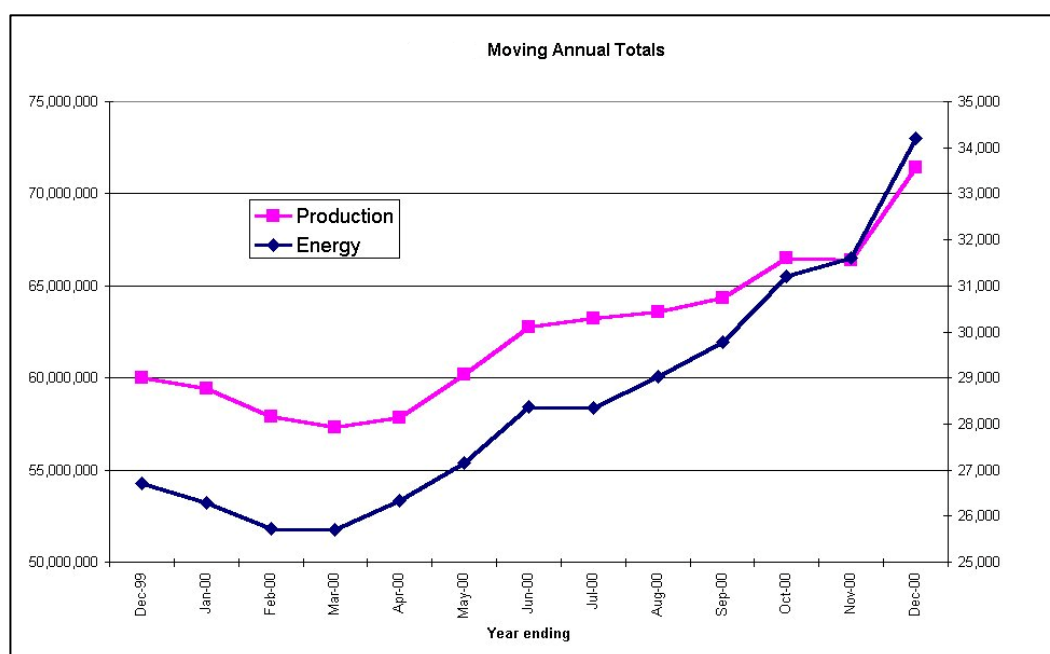


Figure 1.9: Moving Annual Total - Energy and Production

Any deviation in energy line has to be watched so that early warning of energy waste can be detected or alternatively to verify whether energy efficiency measures are making a positive impact.

1.9 Relating Annual Energy and Production using Bar Chart

For any company, energy should directly relate to production. If energy and related production data are available for the 24 months period, it is possible to find the impact of production on energy consumption. For this specific energy consumption (SEC) which is energy consumption per unit of production can be calculated for each month and plotted as shown in Figure 1.10. The chart shows trends very low SEC in December followed by rising trend in SEC.

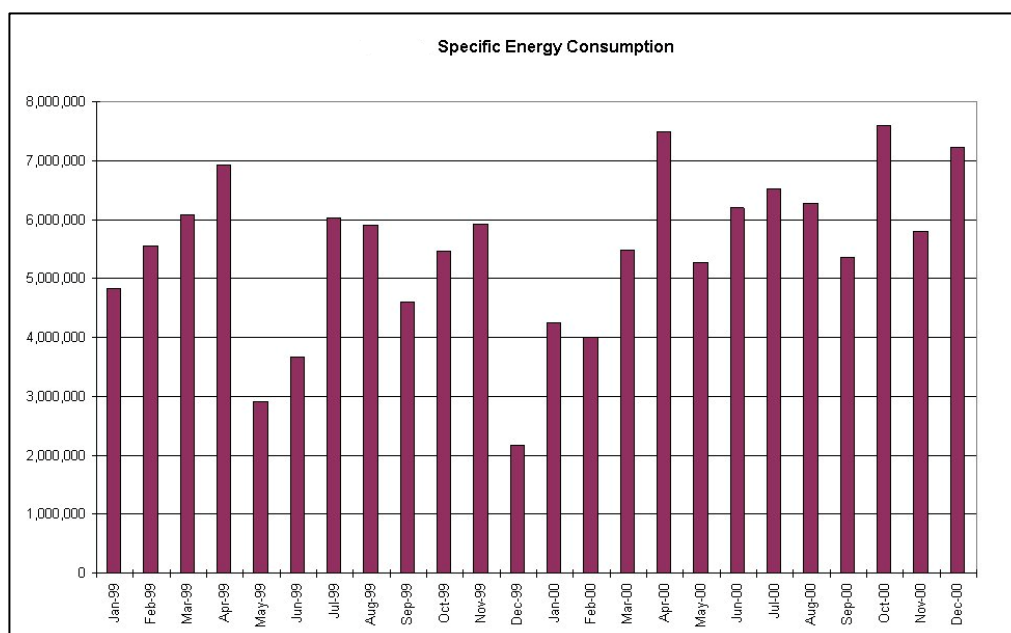


Figure 1.10: Monthly Specific Energy Consumption

The level of production may have an effect on the specific consumption. If production data are included in the SEC chart, understanding becomes even better (Figure 1.11). It can be seen that the low SEC resulted when the production reached a peak. This indicates that there might be fixed energy consumption i.e. consumption that occurs regardless of production levels.

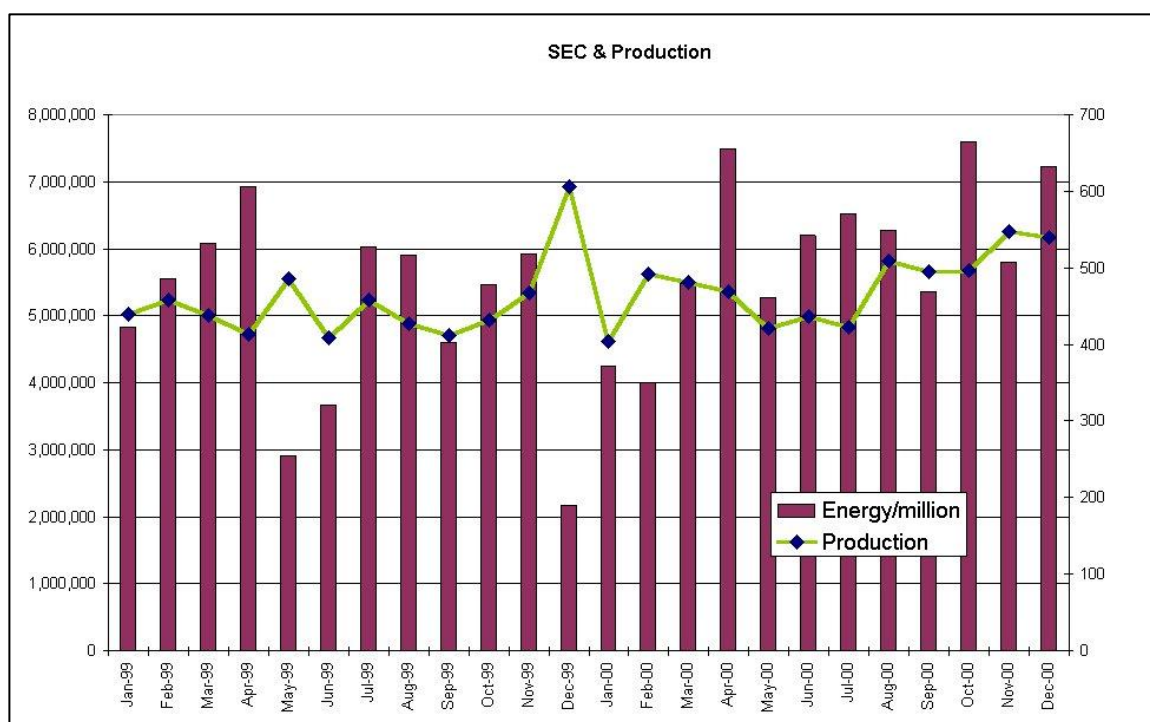


Figure 1.11: SEC and Production

1.10 Linear Regression Analysis

Linear regression analysis is a statistical technique which determines and quantifies the relationship between variables. It is a widely used energy management tool which enables standard equations to be established for energy consumption, often from data which would otherwise be meaningless.

Regression analysis overcomes the limitation of time-dependent analysis by removing the 'time' element from the analysis and focusing instead on the variables which influence energy consumption. It is a versatile technique which can be used to analyse a wide variety of applications. When used as an energy management tool, the variables commonly compared are:

- Natural gas/Furnace Oil consumption versus the number of units of production.
- Electricity consumption versus the number of units of production.
- Water consumption versus the number of units of production.
- Electricity consumed by lighting versus hours of occupancy.

Regression analysis is very much dependent on the quality of the data used. If an analysis indicates the absence of a significant relationship between two variables, it does not necessarily mean that no relationship exists. The significance of results depends on the quantity and quality of the data used, and on the variables used in the analysis. The Table 1.3 shows influencing factors which can impact energy consumption.

Table 1.3: Factors which influence Energy Consumption

Energy	Purpose	Influencing Factors
Electricity	Air compressors	Air volume delivered
Furnace oil	Steam raising in boilers	Amount of steam generated
Steam	Production process	Production volume

a) Single Independent Variable

XY Scatter Diagram

XY Scatter Diagram provides better understanding of relationship between energy and production. For example if energy consumption in tonnes of oil (TOE) equivalent (i.e. a dependent variable) and production in Metric tonnes (MT) (i.e. an independent variable) in a foundry furnace are plotted against each other on a graph a relationship between the two can be obtained as shown in Figure 1.12.

This chart shows a low degree of scatter which is indicative of a good fit. If data fit is poor, it indicates poor level of control and hence a scope for energy savings; for a poor data fit, where relationship is expected, it indicates poor control and hence a potential for energy savings.

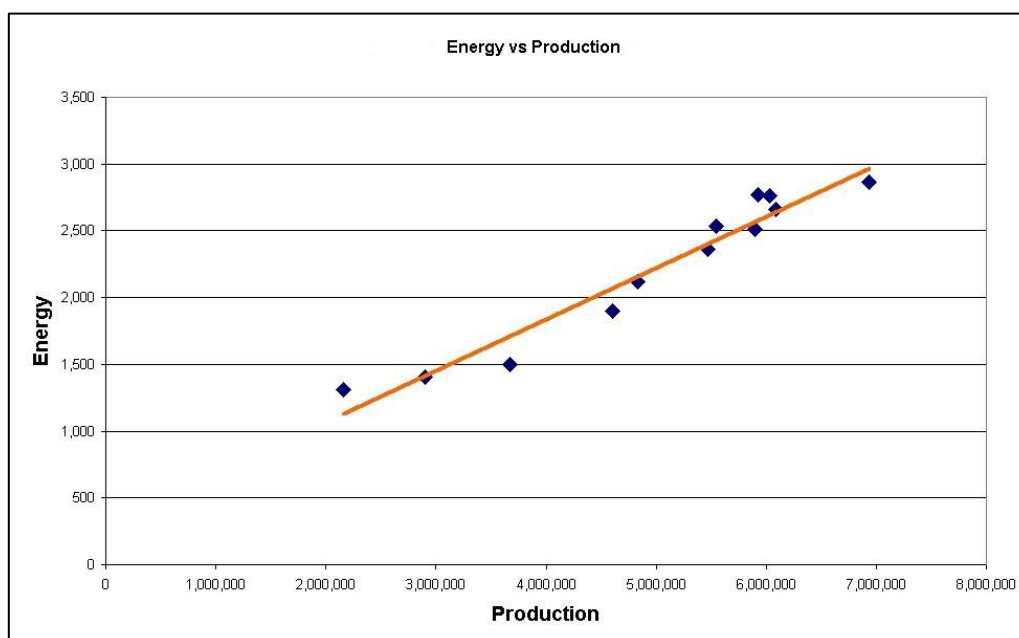


Figure 1.12 XY Chart for Energy-Production Relationship

This relationship is in fact linear and it is possible to derive an equation for the *best-fit* straight-line curve through the points plotted on the graph. The *best-fit* straight-line curve is

determined by summing the squares of the distances from the straight line of the various data points. Once established, this linear equation can be used to predict future energy consumption. In addition, it can be used as a *standard performance* equation for energy *monitoring and targeting* purposes.

The relationship between energy and production, provide basis for performance measurement. Charting energy against production can be carried out easily using XY chart option. Best-fit straight line is obtained if trend line is added to the data set on the chart.

The trend chart can be used to derive "standard" for the up-coming year energy consumption.

In producing the production/energy relationship chart a relationship relating production and energy consumption is obtained as follows:

Energy consumed for the period = $c + m \times$ Production for same period

Where M is the energy consumption directly related to production (variable) and C is the "fixed" energy consumption (i.e. energy consumed for lighting, heating/cooling and general ancillary services that are not affected by production levels). Using this, the expected or "standard" energy consumption for any level of production can be calculated within the range of the data set.

The basis for implementing a factory level M&T system has now been established. The standard energy consumption can be predicted and appropriate targets can be set —*for example, standard energy consumption less 5%*. A better approach might be applying different reductions to the fixed and variable energy consumption. Although, the above approach is at factory level, the same can be extended to individual processes if sub metering is installed. At a simple level, the chart can be used to plot upcoming month energy consumption based on planned production.

The generic equation for a straight–line graph can be represented as follows:

$$y = c + mx$$

Where

y is the dependent variable (e.g. energy consumption),
x is the independent variable (e.g. production),
c is the value at which the straight-line curve intersects the 'y' axis, and
m is the gradient of the straight-line curve.

Energy consumed for the period = $C + m \times$ Production for the same period

If the straight line $y = c + mx$ is best fitted to a set of data sample points; it can be shown that

$$(x_1, y_1) \cdot (x_2, y_2) \cdots \cdots (x_n, y_n)$$

and

$$cn + m\Sigma x = \Sigma y$$

$$c\Sigma x + m\Sigma x^2 = \Sigma xy$$

Where n is the number of data points. These equations are known as the normal equations.

An Example establishing the values of c and m is illustrated as follows:

Consider a foundry which during a monitoring programme produces the following sample data:

Month	1	2	3	4	5	6	7	8	9
Production, Tonnes /month, x	380	440	460	520	320	520	240	620	600
Energy use, Toe / month, y	340	340	380	380	300	400	280	424	420

Therefore:

n	x	y	x²	xy
1	380	340	144400	129200
2	440	340	193600	149600
3	460	380	211600	174800
4	520	380	270400	197600
5	320	300	102400	96000
6	520	400	270400	208000
7	240	280	57600	67200
8	620	424	384400	262880
9	600	420	360000	252000
	4100	3264	1994800	1537280

Therefore, the normal equations become

$$9c + 4100m = 3264$$

$$4100c + 1994800m = 1537280$$

Therefore

$$c = \frac{3264 - 4100m}{9}$$

Therefore

$$4100 (3264 - 4100m)/9 + 1994800m = 1537280$$

$$1486933 - 1867778m + 1994800m = 1537280$$

$$127022m = 50347$$

$$m = 0.4 \text{ and } c = 180$$

The best fit straight line equation is therefore:

$$y = 180 + 0.4 x$$

From this equation, it can be seen that the theoretical base load for furnace is 180 TOE.

The same relationship can be obtained by plotting in a graph as shown in Figure 1.13..

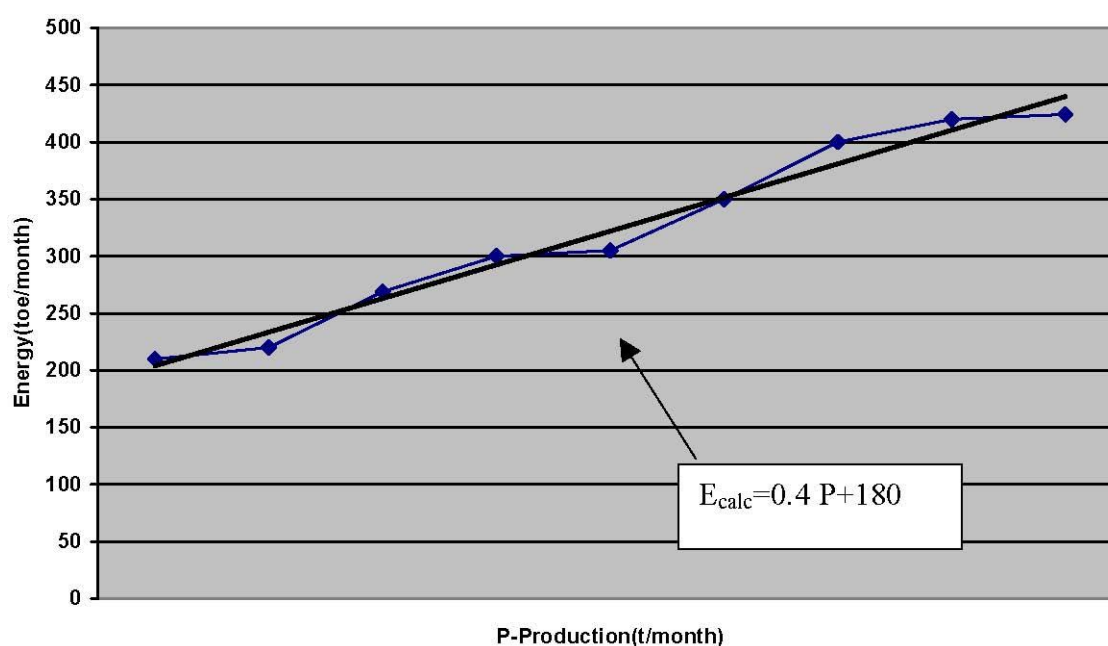


Figure 1.13: Energy-Production Relationships for Foundry

Correlation Coefficients

The regression analysis method enables a *best-fit* straight line to be determined for a sample data set. However, in some circumstances the sample data points maybe very scattered with the result that the derived equation may be meaningless. It is therefore important to determine how well the *best-fit* line correlates to the sample data. This can be done by calculating the *Pearson correlation* coefficient, which gives an indication of the reliability of the line drawn. The Pearson correlation coefficient is a value between 1 and 0, with a value

of 1 representing 100% correlation. The Pearson correlation coefficient (r) can be determined using the following equation:

$$r = \frac{\sum(x - \bar{x})(y - \bar{y})}{\sqrt{[\sum(x - \bar{x})^2 \sum(y - \bar{y})^2]}}$$

Where x , y are the x and y values, and $\bar{x}$, $\bar{y}$ are the average of x and y values. Example 4.3 illustrates how the correlation coefficient may be calculated.

x	y	$(x - \bar{x})$	$(y - \bar{y})$	$(x - \bar{x})(y - \bar{y})$	$(x - \bar{x})^2$	$(y - \bar{y})^2$
380	340	-75.56	-22.67	1712.59	5708.64	513.7778
440	340	-15.56	-22.67	352.59	241.98	513.7778
460	380	4.44	17.33	77.04	19.75	300.4444
520	380	64.44	17.33	1117.04	4153.09	300.4444
320	300	-135.56	-62.67	8494.81	18375.31	3927.111
520	400	64.44	37.33	2405.93	4153.09	1393.778
240	280	-215.56	-82.67	17819.26	46464.20	6833.778
620	424	164.44	61.33	10085.93	27041.98	3761.778
600	420	144.44	57.33	8281.48	20864.20	3287.111
4100	3264	0	0	50346.67	127022.22	20832.00

Therefore,

$$r = \frac{50346.67}{(127022.22 \times 20832)^{0.5}} = 0.98$$

Table 1.4 shows minimum acceptable correlation coefficients for given numbers of data samples.

It can be seen from the Table that the correlation coefficient is very good.

Table 1.4: Minimum Correlation Coefficients (r)

Number of data samples	Minimum correlation coefficient (r)
10	0.767
15	0.641
20	0.561
25	0.506
30	0.464
35	0.425
40	0.402
45	0.380
50	0.362

b) Multi-variable analysis

Often energy consumption can be influenced by several different variables. When this is the case the relationship can be described by the equation:

$$y = c + m_1 x_1 + m_2 x_2 + \dots + m_n x_n$$

where, $x_1, x_2, \dots, x_n$ are the variables that influence y .

It is difficult to solve multivariable analysis by hand calculation. It is therefore advisable to use specialist computer software which can be employed to determine the statistical relationship between the variables.

1.11 CUSUM

Cumulative Sum (CUSUM) represents the difference between the baseline (expected or standard consumption) and the actual consumption points over the baseline period of time. This technique not only provides a trend line, but also calculates savings/ losses and alerts when the energy performance changes.

A typical CUSUM graph follows a trend and showing random fluctuation of energy consumption and should oscillate around standard (or expected) consumption. This trend will continue until something happens which alters the pattern of consumption such as the effect of an energy saving measure or, conversely, a deterioration in energy efficiency (poor control, house-keeping or maintenance).

CUSUM chart (Figure 1.14) for a generic company is shown. The CUSUM chart shows what is really happening to the energy performance. The formula derived from the 1999 data was used to calculate the expected or standard energy consumption.

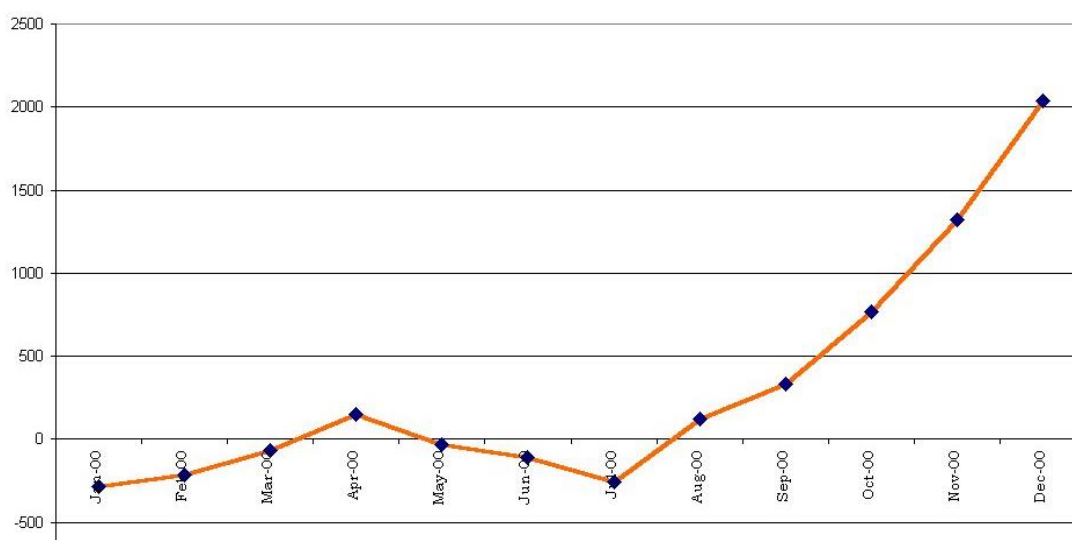


Figure 1.14: CUSUM Chart

From the chart, it can be seen that starting from year 2000, performance is better than standard. Performance then decreased (indicated by upward trend in line) until April, and then it started to improve until July (indicated by downward trend in line).

However, from July onwards, there is a marked, decline in energy performance indicated by upward trend line. When looking at CUSUM M chart, the changes in direction of the line (upwards or downwards) indicate events that have relevance to the energy consumption pattern.

However, site information is needed to interpret the reasons. For this sample company since there have been no planned changes in the energy system, the change in energy performance can be attributed to poor control, housekeeping or maintenance.

Example Illustrating: CUSUM Technique

Energy consumption and production data were collected for furnace in a foundry over a period of 18 months. During month 9, a heat recovery system was installed. Using the plant monthly data, estimate the savings made with the heat recovery system. The plant data is given in Table 1.5:

Table: 1.5: Month Wise Production with Energy Consumption		
Month	E _{act} - Monthly Energy Use (toe * / month)	P - Monthly Production (tonnes / month)
1	340	380
2	340	440
3	380	460
4	380	520
5	300	320
6	400	520
7	280	240
8	424	620
9	420	600
10	400	560
11	360	440
12	320	360
13	340	420
14	372	480
15	380	540
16	280	280

17	280	260
18	380	500

***toe = tonnes of oil equivalent.**

Steps for CUSUM analysis

1. Plot the Energy –Production graph for the first 9 months
2. Draw the best fit straight line
3. Derive the equation of the line (Equation derived is $E = 0.4 P + 180$)
4. Calculate the standard energy consumption based on various production using the equation
5. Calculate the difference between actual and standard energy consumption
6. Compute CUSUM as shown in the following Table
7. Plot the CUSUM graph
8. Estimate the savings accumulated from use of the heat recovery system.

These steps are shown in the Table 1.6.

Table 1.6: CUSUM Calculations					
Month	E_{Act}	P	$E_{Std} = (0.4 P + 180)$	$E_{act} - E_{Std}$	CUSUM (Cumulative Sum)
1	340	380	332	+8	+8
2	340	440	356	-16	-8
3	380	460	364	+16	+8
4	380	520	388	-8	0
5	300	320	308	-8	-8
6	400	520	388	+2	-6
7	280	240	276	+4	-2
8	424	620	428	-4	-6
9	420	600	420	0	-6
10	400	560	404	-4	-10
11	360	440	356	+4	-6
12	320	360	324	-4	-10
13	340	420	348	-8	-18
14	372	480	372	0	-18
15	380	540	396	-16	-34
16	280	280	292	-12	-46
17	280	260	284	-4	-50
18	380	500	380	0	-50

E_{act} - Actual Energy consumption

E_{Std} - Standard energy consumption

From the Figure 8.10, it can be seen that the CUSUM graph oscillates around the zero line

for first 10 months and then drops sharply after 11th month. This suggests that the heat recovery system took almost two months to commission and reach proper operating conditions, after which steady savings have been achieved. Based on the graph 9.10 (see Table 8.4), savings of 44 TOE (50-6) have been achieved in the last 7 months. This represents savings of almost 2% of energy consumption.

CUSUM chart for last 18 months is shown in Figure 1.15. below

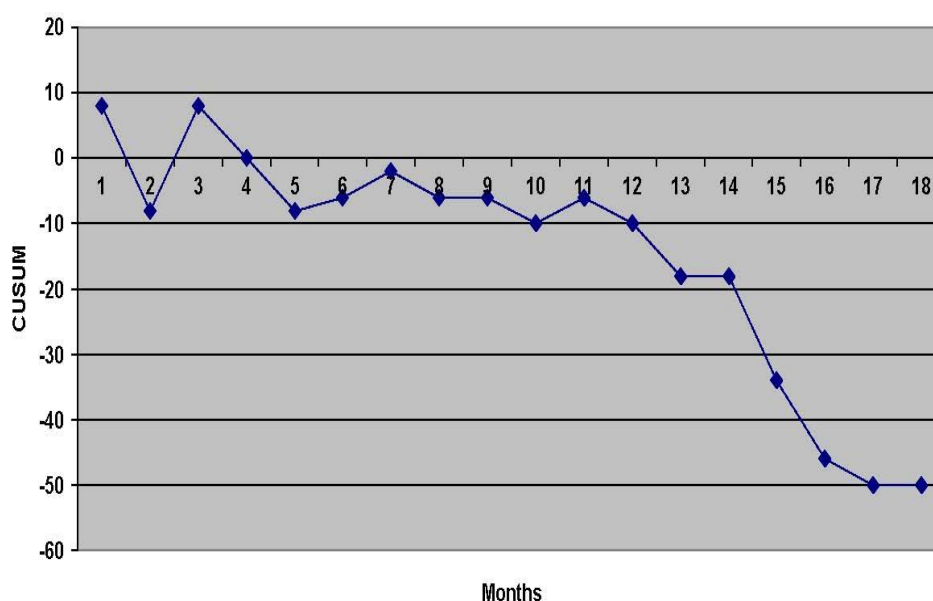


Figure 1.15: Example CUSUM Graph

1.12 Energy Management Information System (EMIS)

The use of specially designed information system software is advisable when operating an M&T programme. However, softwares should not be seen as a replacement for the energy manager, but simply as tools which enable large amounts of data to be stored and analysed quickly. A number of energy management software packages are commercially available, with varying degrees of complexity and costs. However, they all tend to share the following generic features:

- ✓ A database facility, which is capable of storing and organizing large quantities of data collected over a long period of time.
- ✓ The ability to record energy data for all utility types, including data taken from both meters and invoices.
- ✓ The ability to handle complex utility tariffs. Tariffs vary from place to place, and are becoming increasingly complex as competition is introduced into the utilities sector.
- ✓ The ability to handle other related variables such as degree days and production data.

- ✓ A data analysis facility. This is achieved by incorporating statistical analysis software into the energy management software.
- ✓ A reporting facility, which is capable of quickly producing energy management reports.
- ✓ With the more sophisticated energy management packages it is possible to interface the software with Building Management Systems (BMS), so that energy data can be automatically recorded on a regular basis (e.g. hourly).

One of the great advantages of computer-based systems is their database facility, which enables historical data and data from many sources to be instantly compared. This facility is particularly useful when comparing site energy costs on a utility basis and enables energy managers quickly to assess the relative performance of various Energy Accounting Centres (EACs). In this way EACs which are under-performing can be quickly identified and remedial action taken.

Designing Information Reporting Systems

One of the major outputs of any M&T programme is the production of energy management reports. These reports perform the vital role of communicating key information to senior and operational managers, and are therefore the means by which action is initiated within an organization. In order to ensure that prompt action is taken to minimize wasteful practices, reports should be as simple as possible and should highlight those areas in which energy wastage is occurring. Reports should be published regularly so that energy wasteful practices are identified quickly and not allowed to persist too long. Reports should be brief and relevant, and conform to a standard format which should be generated automatically by a computer. This minimizes preparation time, and also familiarizes managers with the information being communicated.

Most M&T programmes require reports to be published weekly or monthly. Monthly reports are usually applicable to large organizations with many sites, with weekly reports being more suitable to complex high energy consuming facilities. In applications where energy consumption is particularly high, reports may be produced daily. If the reporting period is too long, energy may well be needlessly wasted before managers are notified of the problem and remedial action is taken. Yet, if the reporting period is too short this will lead to an over-complex M&T system in which too much irrelevant information requires consideration.

The primary purpose of energy management reports is to communicate effectively with senior and operational managers. They should therefore be tailored to suit the needs of their readers, with different managers within organizations requiring different levels of report. Operational managers may need weekly reports, whereas senior management may only require a quarterly review. Figure 9.14 illustrates the relationship between reporting frequency and managerial status.

One big disadvantage of producing a large number of regular reports is that they can swamp operational managers with what may appear to be irrelevant information. One good way to get around this problem is to adopt a reporting by exception system, in which reports are only generated when energy performance falls outside certain predetermined limits. This system has the great advantage that managers only receive reports when energy performance is either poor or very good. In addition, everyone involved in the reporting process benefits from a reduced workload.

Level	Report frequency			
Senior management	Annual	Quarterly		
Department head	Annual		Monthly	
EAC manager	Annual			Weekly
Energy manager	Annual	Quarterly	Monthly	Weekly

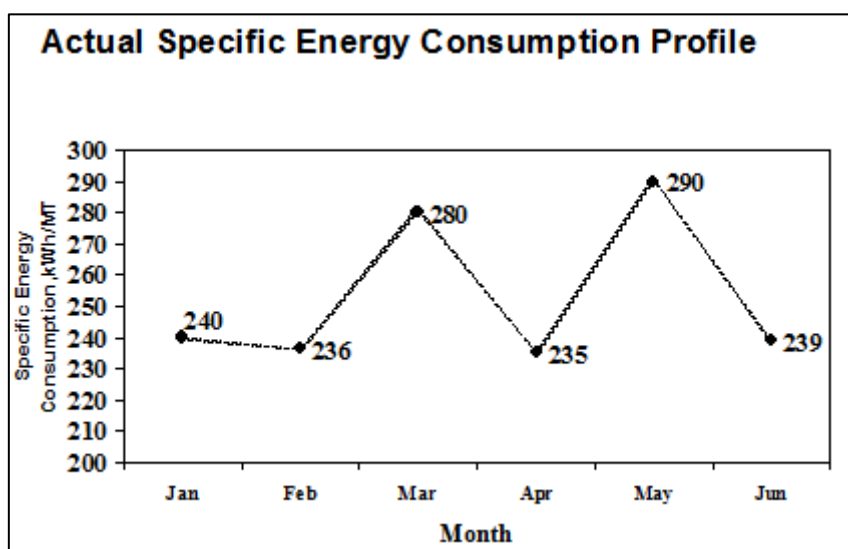
Figure 1.16: Relationships between Managerial Status and Report Frequency

Example-1

Energy saving (retrofit) measures was implemented in a process plant prior to Jan-2017. Use CUSUM technique and calculate energy savings for 6 months period of 2017.

The company produced consistently 3000 T/month in each of the first six months.

Refer the graph given in table below.



The predicted (expected or standard) specific energy consumption for 3000 MT production is 260 kWh/MT.

It may be noted that retrofits were not functioning during March & May 2017.

2017-Month	Actual - SEC, kWh/MT	Predicted SEC- kWh/MT	Difference= Actual- Predicted	CUSUM
Jan	240	260	- 20	-20
Feb	236	260	- 24	-44
Mar	280	260	+ 20	-24
Apr	235	260	- 25	-49
May	290	260	+ 30	-19
Jun	239	260	- 21	-40

Energy Savings for six months = 40 kWh/MT x 3000 MT
= 1.20 lakh kWh

Example-2

Use CUSUM technique to develop a table and to calculate energy savings for 8 months period. For calculating total energy saving, average production can be taken as 6,000 MT per month. Refer to field data given in the table below.

Month	Actual SEC, kWh/MT	Predicted SEC, kWh/MT
May	1311	1335

June	1308	1335
July	1368	1335
Aug	1334	1335
Sept	1338	1335
Oct	1351	1335
Nov	1322	1335
Dec	1320	1335

Month	Actual SEC, kWh/MT	Predicted SEC, kWh/MT	Diff = (Act - Pred) (- = Saving)	CUSUM (- = Saving)
May	1311	1335	-24	-24
June	1308	1335	-27	-51
July	1368	1335	33	-18
Aug	1334	1335	-1	-19
Sept	1338	1335	3	-16
Oct	1351	1335	16	0
Nov	1322	1335	-13	-13
Dec	1320	1335	-15	-28

Savings in energy consumption over a period of eight months are $28 \times 6000 = \underline{1,68,000 \text{ kWh}}$

Example-3

The Energy- production data (for Jan-June, 2011) of an industry follows a relationship :
 Calculated energy consumption = $0.5 P + 220$.

A Waste heat recovery system was installed at end of June 2011 and further data was gathered up to December 2011.

Using CUSUM technique, calculate energy savings in terms of ton of oil equivalent (toe) and the reduction in specific energy consumption achieved with the installation of waste heat recovery system.

The plant data is given in the table below.

2017-Month	Actual Energy Consumption, toe/month	Actual production, ton/month
Jan	620	760
Feb	690	960

Mar	635	790
Apr	628	830
May	545	610
Jun	540	670
July	590	760
Aug	605	820
Sep	670	940
Oct	582	750
Nov	512	610
Dec	540	670

The table below gives values of actual energy consumption Vs. calculated (predicted) energy consumption from July – Dec. 2017.

Specific energy consumption monitored Vs predicted for each month. The variations are calculated and the Cumulative sum of differences is calculated from Jan-June-2017.

2017-Month	E_{act}	$E_{cal} = 0.5P + 220$	$E_{act} - E_{cal}$	CUSUM
July	590	600	-10	-10
Aug	605	630	-25	-35
Sept	670	690	-20	-55
Oct.	582	595	-13	-68
Nov.	512	525	-13	-81
Dec.	540	555	-15	-96

Energy savings achieved = **96 toe**

Reduction in specific energy consumption = $96/4550 = 0.021$ toe/tonne of production
(Production for 6 months = $760+820+940+750+610+670 = \mathbf{4550}$ tonnes)

Example-4

Use CUSUM technique and calculate energy savings for first 6 months of 2011 for those energy saving measures implemented by a plant prior to January, 2011.

The average production for the period Jan-Jun 2011 is 1000 MT/Month

The plant data is given in the following table:

2011-Month	Actual Specific Energy Consumption, kWh/MT	Predicted Specific Energy Consumption, kWh/MT
Jan	1203	1121
Feb	1187	1278
Mar	1401	1571
Apr	1450	1550
May	1324	1284
Jun	1233	1233

2011-Month	Actual - SEC, kWh/MT	Predicted SEC- kWh/MT	Difference= Actual- Predicted	CUSUM
Jan	1203	1121	82	82
Feb	1187	1278	-91	-9
Mar	1401	1571	-170	-179
Apr	1450	1550	-100	-279
May	1324	1284	40	-239
Jun	1233	1233	0	-239

$$= 239 \text{ kWh/MT} \times 1000 \text{ MT} \times 6 \text{ months}$$

$$\text{Energy Savings for six months} = -239,000 \text{ kWh}$$