Index for the books

UN environment

CTCN
CLIMATE TECHNOLOGY CENTRE & NETWORK

Book 1:
General Aspects of Energy Management
And
Energy Audit

Guide Book
For
National Certification Examination
For Energy Auditors and Managers

NEECA

National Energy Efficiency and Conservation Authority

Acknowledgements

The United Nations Industrial Development Organization (UNIDO), CTCN and the Government of Pakistan (GOP) have decided to join hands to implement technical assistance for National Certification Scheme for Energy Auditors and Managers in Pakistan that would device a sustainable system for training and certifying energy auditors and managers as a contribution to the implementation of the National Energy Efficiency and Conservation Act, 2016.

One of the main tasks of the project was finalization of syllabus and course modules including the development of model question banks for examination processes. This task was entrusted to a consortium of experts from two organizations, namely The Energy and Resources Institute (TERI) and PITCO from Pakistan.

This Book covers details of energy scenario in Pakistan, the various provisions under the National Energy Efficiency and Conservation Act 2016, details of energy management and auditing, ISO 50001:2018, financial analysis and various financing options for energy efficiency improvement in industries.

The members of consortium would like to express their gratitude to:

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Their comments and feedback helped the consultants to make sure that recommendations made were the most appropriate and fair in terms of benefits to the project developers, the government and other relevant partners.

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Chapter 1 Energy Scenario

1.1 Introduction

Energy is the primary requirement for economic development of any country. For developing countries, energy sector is of critical importance to meet the ever increasing energy needs.

Energy used for daily activities can be classified into following categories:

- Primary and secondary energy
- Renewable and non-renewable energy

1.1.1 Primary and Secondary energy

All types of energy which can be extracted or tapped directly from natural resources are known as primary energy. Primary energy sources can further be converted into secondary energy sources like electricity and steam.

Primary energy content of all fuels is generally expressed in terms of tonnes of oil equivalent (toe)

1 tonne of oil equivalent = 10×10^6 kCal = 11,630 kWh = 41,870 MJ

Coal, oil, natural gas and uranium are all examples of primary energy. These can be converted to electricity and steam which are classified as secondary energy.

1.1.2 Renewable and non-renewable energy

Energy obtained from inexhaustible sources like the sun, wind, tidal waves, geothermal source etc. is classified as renewable energy. The use of renewable energy ensures that no additional carbon dioxide is released into the atmosphere.

Non-renewable sources on the other hand are those which exist in a fixed or limited quantity on earth and their rate of replenishment is far lower than the rate of consumption. Coal, oil, natural gas, nuclear energy all constitutes non-renewable sources of energy.

1.2 World Energy Scenario:

Global primary energy consumption comprising commercially traded fuels including renewable energy was 13,865 million tonnes oil equivalent (MTOE) in 2018. There has been 2.9% increase in global primary energy consumption in 2018 as compared to 2019. An increase of 1.5% was observed for Organization for Economic Co-operation and Development (OECD) countries and 3.9% for Non-OECD countries. The world primary energy consumption trend is shown in Figure1.1.

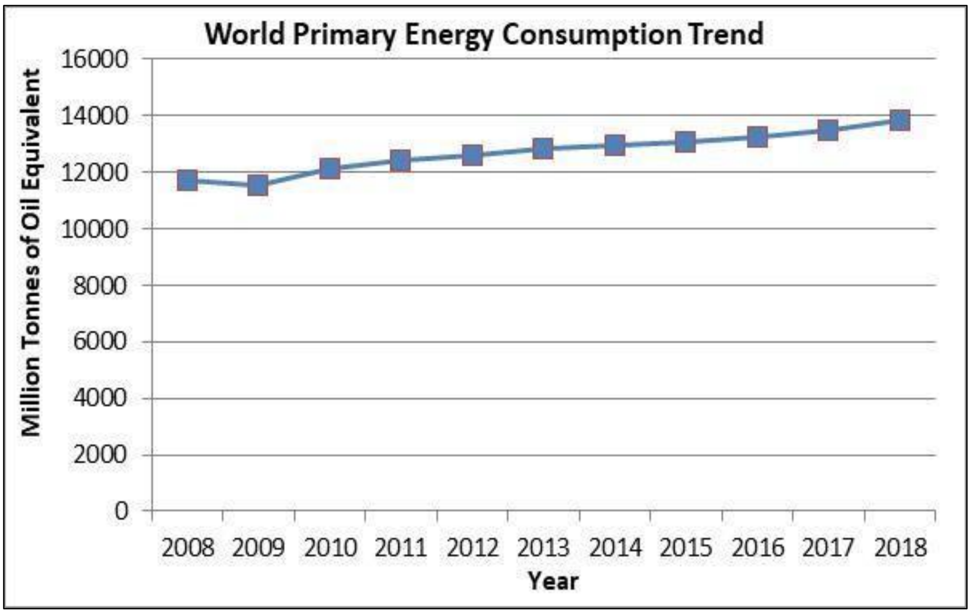


Figure 1.1: World primary energy consumption trend

Source: BP Statistical Review of World Energy 2019

Oil, natural gas and coal have been the world's primary energy source for several decades. Currently, conventional fossil fuels supply about 84.7% of the global primary energy consumption for industrial, transportation, commercial and residential uses. The world primary energy consumption by fuel type/source is shown in Figure1.2.

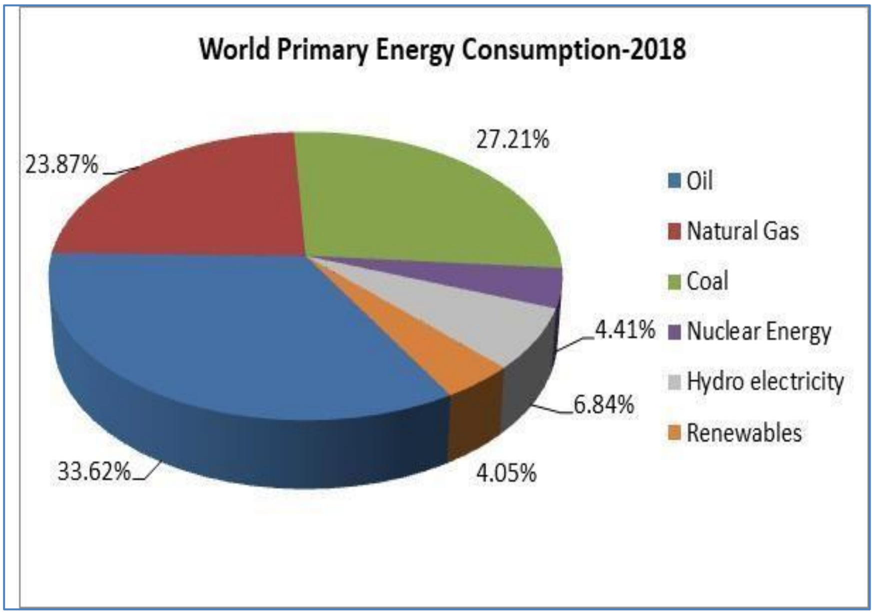
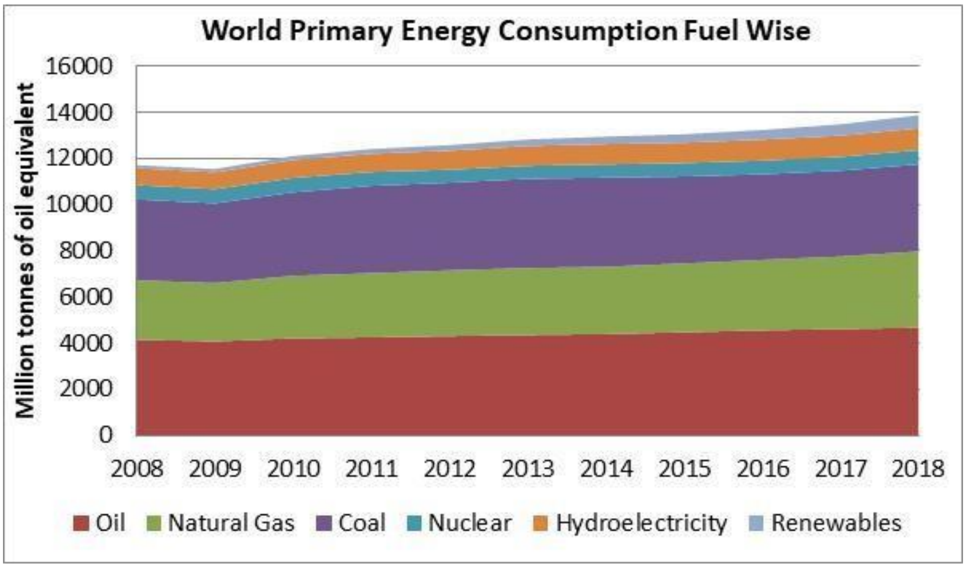


Figure 1.2: Breakup of World Primary Energy Consumption by Fuel/Source

Source: BP Statistical Review of World Energy 2019

The fuel-wise world primary energy consumption trend is shown in figure 1.3.



The current consumption trend of fossil fuels is not sustainable keeping in view the limited resources available.

The global Reserve/Production ratio shows that oil reserves in 2018 accounted for 50 years of current production, natural gas reserves in 2018 accounted for 50.9 years of current production and coal reserves in 2018 accounted for 132 years of current production.

Moreover, the global environment is worsening due to increasing greenhouse gas (GHG) emissions caused by fossil fuels. The world carbon dioxide (CO_2) emission trend is shown in Figure 1.4.

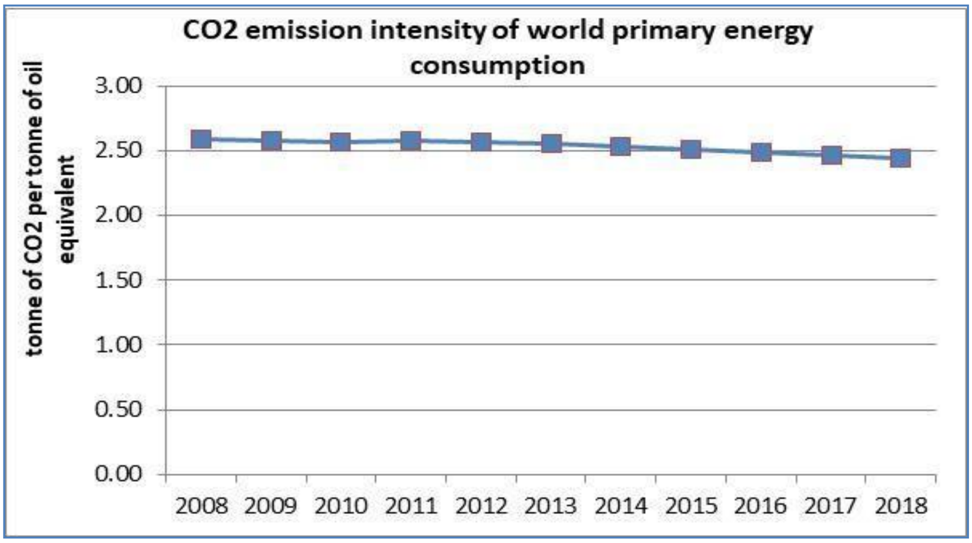


Figure 1.4: Carbon dioxide intensity of World Primary Energy Consumption

Source: BP Statistical Review of World Energy 2019

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 only produces about half of the CO2 emissions by coal when burned to generate power.

1.3 Pakistan Energy Scenario

Pakistan's Primary energy consumption has been increasing steadily, with a 36% increase from 2008 to 2018. Its primary energy consumption was 85 million tonnes of oil equivalent in 2018, which is about 0.6% of the world's consumption. The primary energy consumption trend of Pakistan is shown in Figure 1.5.

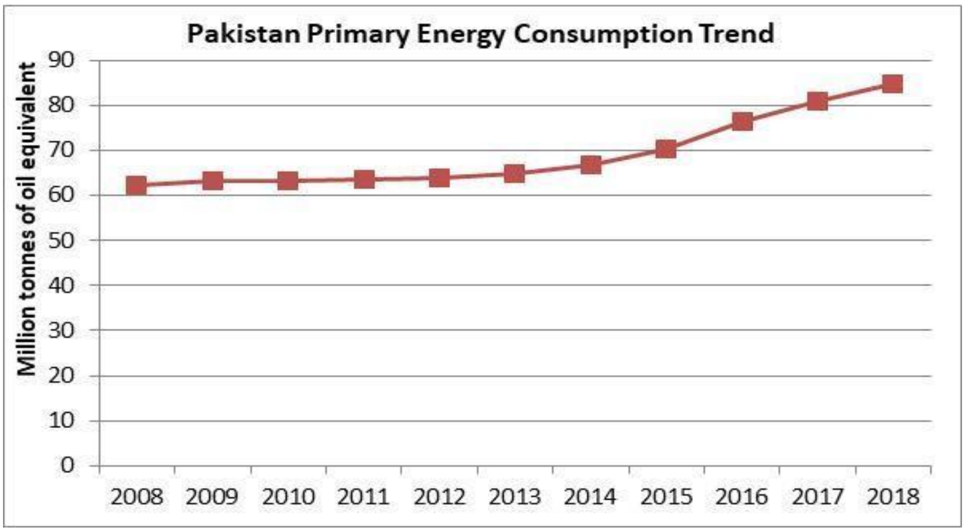


Figure 1.5: Pakistan Primary Energy Consumption Trend
Source: BP Statistical Review of World Energy 2019

From 2014 onward, Pakistan has seen an average growth rate of 5.6% in primary energy consumption. The fuel-wise primary energy consumption trend of Pakistan is shown in Figure 1.6.

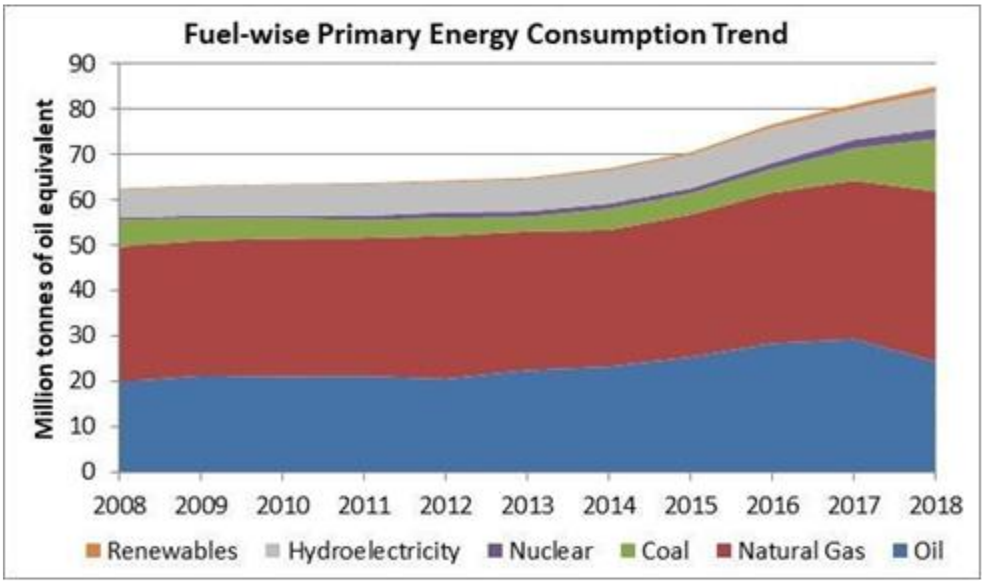


Figure 1.6: Pakistan Primary Energy Consumption Trend (fuel-wise)
Source: BP Statistical Review of World Energy 2019

Natural gas is the largest contributor to Pakistan's primary energy consumption mix accounting for 44.2%of total consumption, followed by oil, which contributes 28.6%.

1.4 Natural Gas

Natural gas is the major fuel for Pakistan. Till 2014, 100% of natural gas used in Pakistan was from indigenous production. Natural gas is available in the four provinces, namely Balochistan, KPK, Punjab and Sindh, with Sindh being the major producer contributing 64% of the national production. A summary of oil reserves and consumption of oil in Pakistan in 2017-18 is given in Table 1.1.

Table 1.1: Summary of oil reserves and consumption of oil in Pakistan in 2017-18

Particulars	Value
Reserve(Balance recoverable)	19.5 trillion cubic feet
Production	3,997 million cubic feet/day
Consumption	1,455 billion cubic feet
LPG Supplies	1.19 million tonnes
LPG Consumption	1.28 million tonnes
LPG Import	313,902,345 MMBTu

Source: Pakistan Energy Yearbook 2018

The province-wise natural gas production from 2012-13 to 2017-18 is given in Table 1.2.

Table 1.2: Province-wise natural gas production in Pakistan

Province	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
	Million tonnes of oil equivalent					
Balochistan	5.422	5.15	5.019	5.564	5.727	5.36
KPK	3.185	3.427	3.352	3.558	3.817	3.99
Punjab	1.606	1.469	1.216	1.224	1.286	1.41
Sindh	20.939	20.907	20.417	20.097	19.358	19.112
Total	31.152	30.953	30.004	30.443	30.188	29.872

Source: Pakistan Energy Yearbook 2018

During 2012-13, Pakistan natural gas production was at its peak and it has been gradually decreasing. By end of 2018, Pakistan had around 0.4 trillion cubic meters of proven natural gas reserves, which accounts for only 10.7 years of current production. From 2015 onward, Pakistan started importing LNG to meet the increased demand. The production, consumption and import data of natural gas from 2008 to 2018 is shown in Figure 1.7.

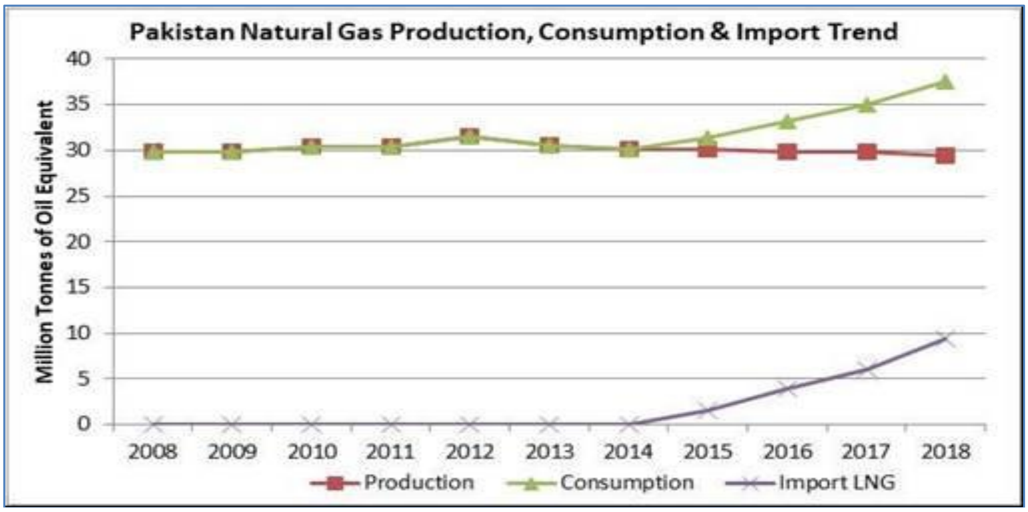


Figure 1.7*:* Production, consumption and import data of natural gas.

Source: BP Statistical Review of World Energy 2019

In 2018, Pakistan imported LNG from14 different countries with major portion from Qatar followed by Nigeria. The distribution of gas consumption in different sectors in the year 2017-18 is given in Table 1.3.

Table 1.3: Sector wise natural gas consumption

Particulars	**Natural Gas**	
	toe	**% share**
Electric power station (Including auxiliary energy consumption)	11.05	35.4
Consumption for non-energy use	3.50	11.2
Domestic sector	6.65	21.3
Commercial sector	0.75	2.4
Industrial sector	7.64	24.5
Transportation sector	1.65	5.3

Source: Pakistan Energy Yearbook 2018

Pakistan's LPG consumption has been growing steadily with exponential increase during 2015-16 and a steady growth is expected to continue in coming years. Government wants to promote LPG as an alternative to conventional biomass as LPG is widely available, highly energy efficient and has less CO2 and air-polluting particles emission than combustion of conventional solid biomass with less risk of deforestation by over exploitation of forest resources. The Oil and Gas Regulatory Authority (OGRA) has issued licenses for establishment of LPG outlets. The sector-wise LPG consumption data is given in Table 1.4.

Table 1.4: LPG consumption in tonnes and year on year percentage increase in consumption

Sector	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**
Domestic	227,287	239,850	288,963	430,212	454,623	495,809
Commercial	188,116	225,892	287,762	413,426	431,220	515,780
Others	73,013	75,491	122,428	275,152	323,577	268,962
Total	488,416	541,233	699,153	1,118,790	1,209,420	1,280,551
Increase in consumption		10.8%	29.2%	60.0%	8.1%	5.9%

Source: Pakistan Energy Yearbook 2018

1.5 Oil

Oil is Pakistan's second major primary energy source. Petroleum is the major import for Pakistan. Pakistan imports petroleum in the form of refined petroleum and crude petroleum. In 2017, refined petroleum constituted 12.6% of Pakistan's total import value and crude petroleum represented 5.2%. A summary of oil reserves and consumption of oil in Pakistan in 2017-18 is given in Table 1.5.

Table 1.5: Pakistan oil reserves and consumption in 2017-18

Particulars	Value
Reserves(Balance Recoverable)	47.47 Million Tonnes
Production	4.5 Million Tonnes
Refining Capacity	19.37 Million Tonnes per Year
Crude Processed	14 Million Tonnes
Refinery Production	13.6 Million Tonnes
Consumption	24.6 Million Tonnes
Import of crude	10.3 Million Tonnes

Source: Pakistan Energy Yearbook 2018

Crude oil is mainly available in the provinces of KPK, Sindh and Punjab, with a very small portion in Balochistan. KPK is the major producer, contributing 50.2% of the national production in 2017-18, followed by 31.9% from Sindh. The province wise petroleum production from 2012-13 to 2017-18 is given in Table 1.6.

Table 1.6: Province-wise petroleum production in Pakistan

Province	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
	US Barrels					
Balochistan	20,154	27,983	38,785	38,150	35,343	29,392
KPK	11,246,372	14,856,959	16,279,020	15,851,634	17,014,317	16,344,032
Punjab	5,263,072	5,058,633	5,158,576	5,481,675	6,077,518	5,798,037
Sindh	11,311,377	11,641,150	13,013,672	10,280,724	9,142,239	10,385,592
Total	27,840,975	31,584,725	34,490,053	31,652,183	32,269,417	32, 557,053

Pakistan's share of world oil consumption is 0.26% which was about 498 thousands of barrels per day (2018).Pakistan's oil production, consumption and import trend is shown in Figure 1.8.

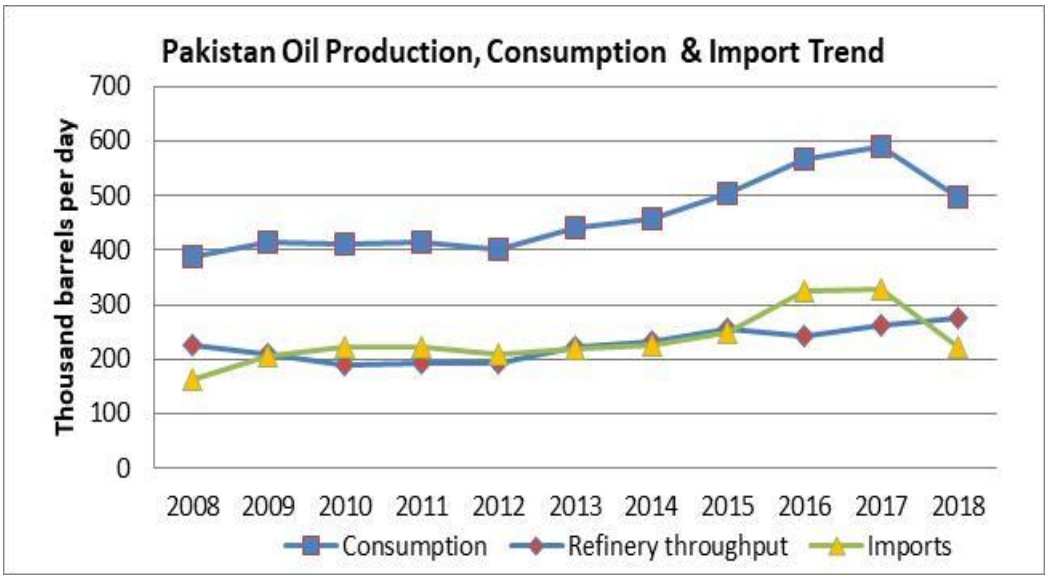


Figure 1.8: Production, consumption and import data of Oil.
Source: BP Statistical Review of World Energy 2019

In 2017, Pakistan imported 60% refined petroleum from UAE followed by 14% from Kuwait, 9.3% from the Netherlands and 7% from Oman since the consumption was higher than refinery throughput. Also, Pakistan imported 59% of crude petroleum from UAE and 41% from Saudi Arabia.

The transport sector has the largest share (59.8%) in petroleum (oil) consumption, followed by the power sector. The growing mobility and increasing demands for passenger and freight movement has increased the consumption of petroleum products in the road transport sector. The distribution of oil consumption is shown in Table 1.7.

Table 1.7: Petroleum Consumption Sector-wise

Particulars	**Petroleum Product**	
	toe	**% share**
Electric power station (Including auxiliary energy consumption)	6,470,741	24.6
Consumption for non-energy use	605,016	2.3
Domestic sector	68,162	0.3
Industrial sector	1,785,880	6.8
Agricultural sector	15,134	0.1
Transportation sector	16,988,579	64.5
Other Government usage	407,198	1.5
Total consumption	26,340,710	100

Source: Pakistan Energy Year book 2018

Pakistan’s current daily oil demand is around 67,927 tonnes, and the self-sufficiency rate is 55%. Over the years, there has been a continuous increase in the quantity of oil imported. However, there was a drop in the import quantity in 2017-18 mainly due to increase in Pakistan’s own refinery throughput and shift from oil to natural gas for power generation.

1.6 Coal

Coal is the third most consumed primary fuel in Pakistan. In 2017, coal briquettes constituted 1.8% of Pakistan's total import value. A summary of coal reserves and consumption of Pakistan in 2017-18 is given in Table 1.8.

Table 1.8: Coal reserves and consumption of Pakistan in 2017-18

Particulars	Values
Measured reserves	7,775.5 million tonnes
Production	4.3 million tonnes
Import	13.7 million tonnes
Consumption	17.9 million tonnes

Source: Pakistan Energy Year book 2018

Balochistan has the largest share of indigenous coal production (35.5% in 2017-18), followed by Sindh (30.5% in 2017-18), Punjab (23.4% in 2017-18) and KPK (10.6%).The province wise indigenous coal production and coal imports from 2012-13 to 2017-18 is given in Table 1.9.

Table 1.9: Province wise coal production in Pakistan

Production, Million Tonnes	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Balochistan	1.15	1.35	1.66	2.06	1.75	1.52
Punjab	0.60	0.68	0.66	0.94	0.99	1.00
Sindh	1.16	1.16	1.12	0.75	1.07	1.31
KPK/FATA	0.27	0.24	0.27	0.39	0.36	0.46
Import	3.71	3.12	5.00	4.89	7.02	13.68
Total	6.89	6.56	8.72	9.03	11.19	17.98

Source: Pakistan Energy Year book 2018

Coal production and consumption trend of Pakistan is shown in Figure 1.9.

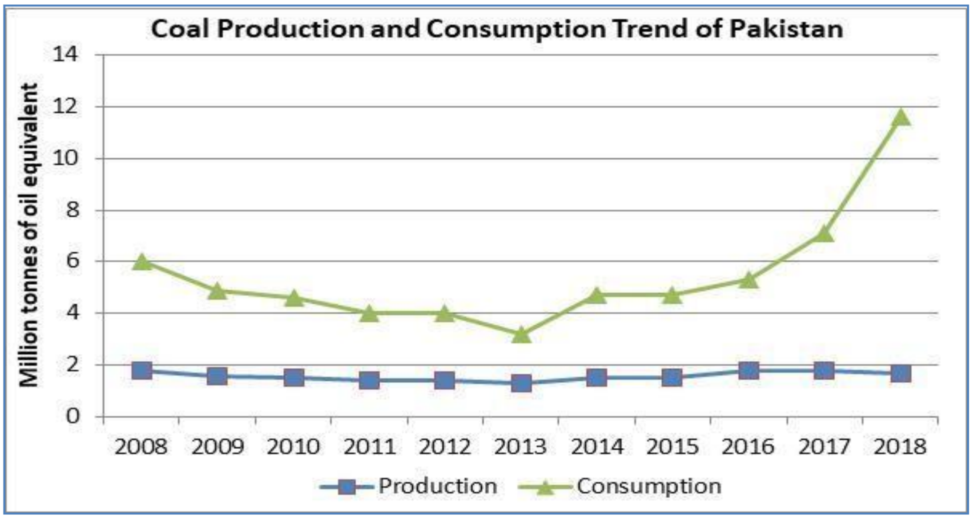


Figure 1.9: Pakistan coal production and consumption trend

The rise in consumption is mainly due to increase in power generation from coal based power plants. From 2016 onwards, there has been an exponential increase in Pakistan's coal consumption as well as coal imports. Pakistan imports 75% of coal briquettes from South Africa, 16.4% from Indonesia and 6.6% from Afghanistan.

Coal is mainly used in cement sector and brick kilns. Figure 1.10 shows the sector wise consumption share of coal in Pakistan.

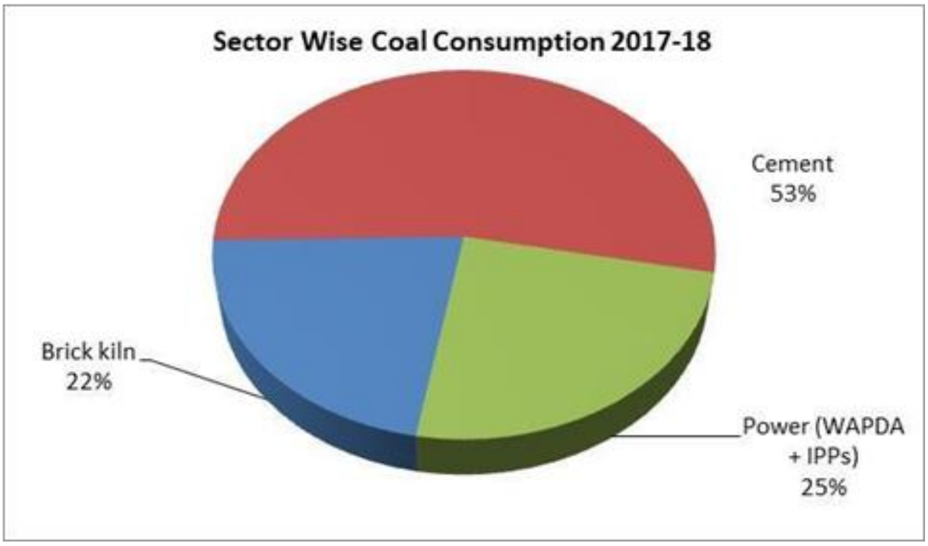


Figure 1.10: Sector wise consumption of coal

Source: Pakistan Energy Year book 2018

1.7 Electricity Supply Trend

Average electricity demand in Pakistan is growing at over 6% per year, owing to rapid economic growth, industrialization, expansion in grid connection and inclusion of new electrical devices and appliances.

In 2018, Pakistan's total installed capacity for electricity generation was 33.5GW, of which 21.3% is hydroelectric power plants, 69.6% is thermal power plants, 4.3% is nuclear plants and 4.9% is renewable energy. In recent years, fuel oil based units have been upgraded to gas fired units. The electricity generation trend of Pakistan is shown in Figure 1.11.

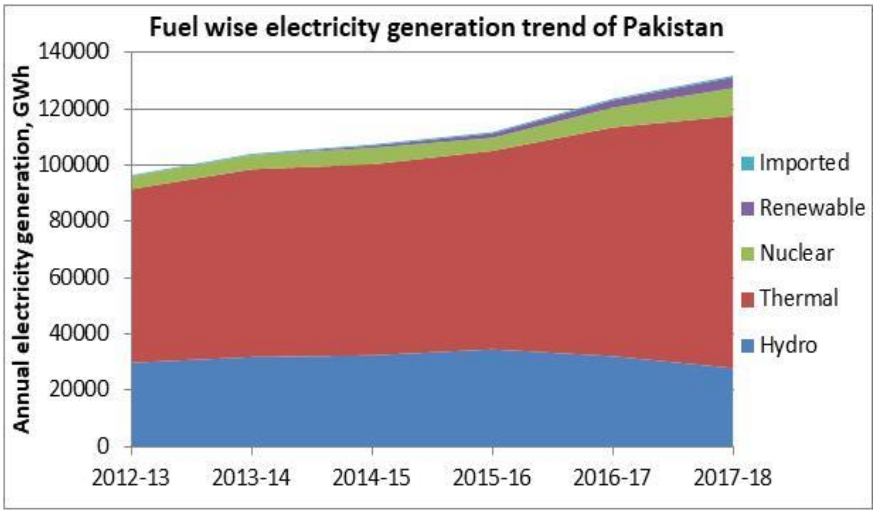


Figure 1.11: Electricity generation trend of Pakistan

In FY 2017-18, of the total thermal power generation, 44%was gas based, 33% oil based, 2% coal based and remaining 11% was RLNG based. Since 2017, electricity generation using coal has increased exponentially. Most of these coal based power plants belong to Independent Power Producers. Over the years there has been considerable impact on the cost of grid electricity, mainly due to the variations in global oil market. Average levellised tariffs determined by NEPRA for recent projects in Pakistan, shows that renewable have a much lower cost compared to all fossil fuels.

According to a World Bank report on electricity access in Pakistan, over 83% of rural areas have grid connectivity. A break-up of sector-wise electricity consumption for FY 2017-18 is given in Table 1.10.

Table 1.10: Sector wise electricity consumption in GWh for FY 2017-18

Sector	Punjab	Sindh	KPK	Balochistan	AJK	Total	Share (%)
Domestic	35,216	11,270	6,124	672	745	54,027	50
Commercial	5,312	2,292	776	131	95	8,606	8
Industry	19,327	5,349	2,550	173	69	27,468	26
Agriculture	5,476	769	121	3,762	-	10,128	10
Street lighting	232	222	13	8	-	474	0.4
Bulk Suppliers	3,958	784	651	122	-	5,514	5
Other Govt.	197	164	43	47	256	708	0.7
Total	69,718	20,849	10,278	4,915	1,166	106,926	100

Source: Pakistan Energy Year book 2018

Domestic sector is the major electricity consuming sector followed by industries.

1.8 Renewable Energy:

Solar, wind and bagasse are the major sources of renewable energy for Pakistan. In FY 2017-18, renewable energy constituted 3% of the total electricity generation mix. Renewable also form 4.9% of the total installed electricity generation capacity of Pakistan. The Alternative Energy Development Board is the agency responsible for developing and encouraging renewable energy projects in Pakistan.

1.8.1 Wind Energy Projects:

Pakistan has a wind energy potential of 50GW at a height of 50m above sea level. The NREL wind speed potential estimation project has identified the Karachi-Hyderabad region, especially the hill top areas, ridges in the Northern Indus Valley, wind corridor areas in Western Pakistan and high mountainous regions in South–Western Pakistan as potential wind energy project sites. The coastal belt of Pakistan is estimated to have a wind corridor of 60km width and 180km length. Pakistan wind energy resource potential map is shown in Figure 1.12.

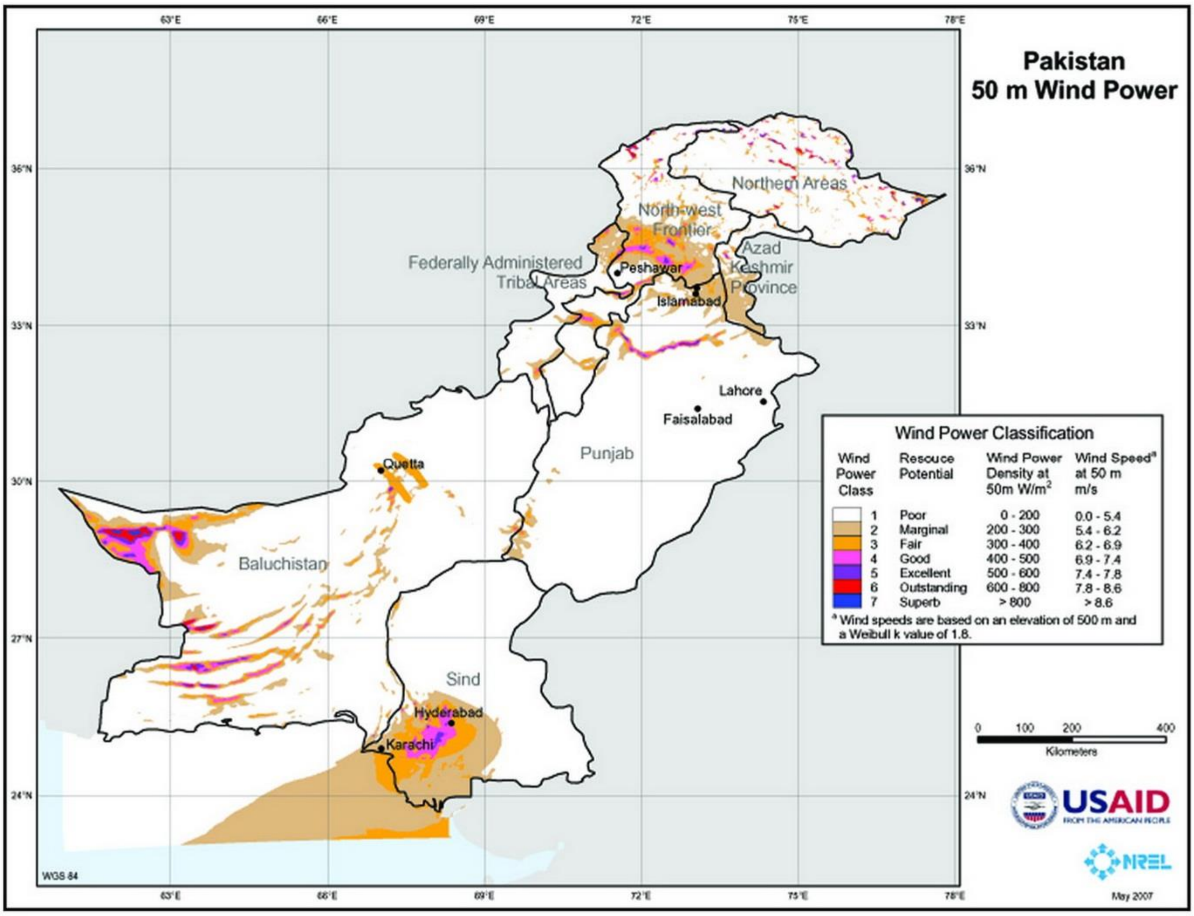


Figure 1.12: Wind resource potential map of Pakistan

By end of 2018, Pakistan had a total installed wind power generation capacity of 1,006MW.

1.8.2 Solar Energy Projects

Solar energy is the second major source of renewable energy for Pakistan. As of 2018, Pakistan had a total installed capacity of 430MW. The south western province of Balochistan and south eastern province of Sindh have the highest solar potential in Pakistan. Estimated solar power generation potential of Pakistan is around 2900GW. Pakistan started commissioning solar projects since 2007and the largest solar park, Quaid-e-Azam Solar Park was commissioned in 2015 with an installed capacity of 400MW. Multiple private companies have also commissioned solar PV plants throughout Pakistan. In addition decentralized generation has also been employed to provide electrification to remote villages. 3000 homes have been electrified with a cumulative capacity of 200kW solar PV by AED Bin Kohat (KPK), DG Khan, Rawalpindi (Punjab) Tharparkar (Sindh), Turbat/Kalat (Baluchistan). PCRET also electrified 500 numbers of schools, houses and mosques with cumulative solar PV capacity of 80kW.

1.8.3 Bagasse Based Generation

Pakistan is the fifth largest producer of sugarcane. At present, Pakistan has around 83 sugar mills with total crushing capacity of 745,000TCD, and installed co-generation capacity of 745MW. Bagasse based power generation accounts for a total generation of

988GWh in FY2017-18. Bagasse based power plants contributed 25.6% of the renewable energy generation in FY 2017-18.

1.9 Energy Balance in Pakistan

Figure 1.13 shows the energy balance of Pakistan in FY2017-18, based on the data from Pakistan Energy Year book 2018. Primary energy supply of Pakistan is 86,301 thousand toe, of which 43.3% is dependent on natural gas, followed by 32.4% of on petroleum products & LPG, 12.6% on coal and remaining 13.5% from hydro, nuclear and other imported electricity.

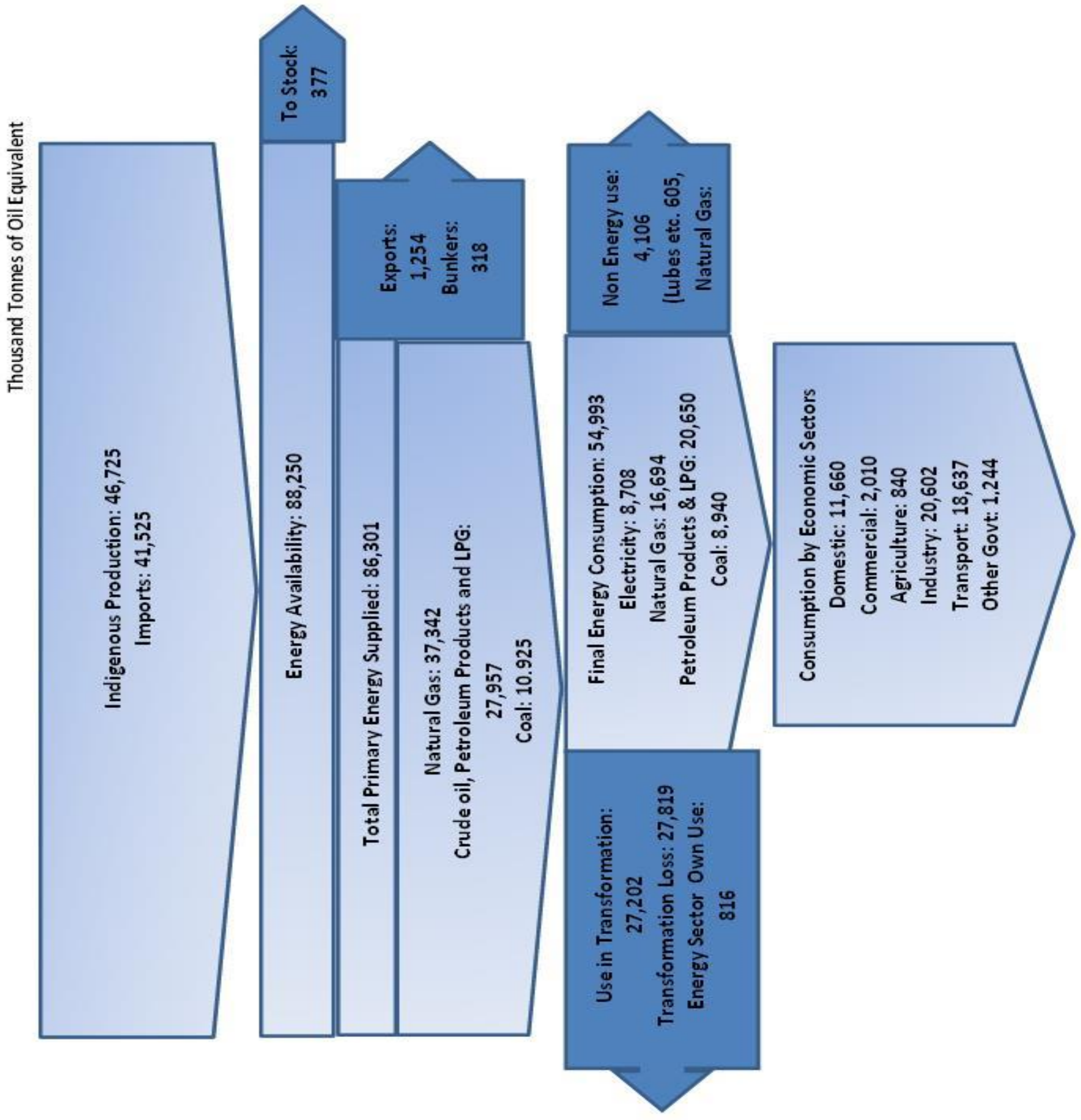


Figure 1.13: Energy balance of Pakistan in FY2017-18

Source: Pakistan Energy Yearbook 2018

1.10 National Energy Efficiency and Conservation Act 2016

The National Energy Conservation and Efficiency Act (NEECA Act 2016) provides the governance framework that can facilitate national efforts for wide scale adoption of sound energy efficient practices. The Act declares the National Energy Conservation and Efficiency Authority (NEECA) as the apex agency to coordinate and catalyze efforts to promote conservation in all sectors of economy and NEECA has been entrusted with a wide range of regulatory responsibilities. The Act also recognizes the crucial role the Provinces can play in implementing country efficiency initiatives and allows for them to tailor their activities in a manner consistent with individual provincial priorities.

Few of the powers vested in NEECA by the Act include:

- initiating demonstration and research and development programs
- taking up capacity building and institutional development initiatives
- establishing accredited laboratories for carrying out testing and analysis
- recommending to Federal or Provincial Government, fiscal and financial incentives for achieving energy conservation objectives
- carrying out energy audits either by itself or through certified individuals for factories, building premises etc. for identifying energy conservation measures
- prohibiting manufacture, sales or import of equipment or appliances which are not energy efficient etc.

In addition, the Act also states the power and function of Federal Government to facilitate and enforce efficient use of energy. Few of the powers entrusted on Federal Government are:

- specify norms/specifications for process and energy consumption standards for equipment
- direct display of energy consumption data on labels of equipment
- specify any user or class of users of energy in the energy intensive industries and other establishments as designated consumer
- establish and specify energy consumption norms and standards for designated consumers
- direct designated consumers to get energy audits conducted by accredited energy auditor at prescribed intervals
- direct designated consumer to furnish to designated agency, information pertaining to energy consumption and action taken on recommendations of accredited energy auditor
- direct designated consumer to appoint energy manager in charge of energy efficiency and conservation related activities
- prescribe minimum qualification for energy auditors and managers
- prescribe energy conservation building codes
- arrange and organize trainings for personnel and specialist in technique for efficient use of energy
- prescribe penalties for energy inefficient apparatus, equipment, plant and machinery

The Federal Government is also empowered to issue energy saving certificates to designated consumers whose energy consumption is below the prescribed norms. Such energy saving certificates can be traded in open market and the designated consumers whose energy consumption is higher than the prescribed norms are obligated to purchase the energy saving certificates.

Keeping in view the need for accommodating certain local necessities and scenarios, the Provincial Governments are also empowered to:

- amend energy conservation building codes to suit regional and local conditions
- direct all owners/occupiers of building complexes being designated consumers to comply with provisions of energy conservation building codes
- direct such designated consumers (building owners) to conduct energy audits through accredited energy auditor
- establish and designate laboratories duly certified by Federal Government

As part of implementation of National Energy Efficiency and Conservation Act, in 2016, the Punjab Energy Efficiency and Conservation Authority (PEECA) was established. PEECA was the first designated agency to launch the energy efficiency standards and label programme for appliances. As of September 2017, 83,100 lower efficiency fans were replaced with high energy efficient fans in Punjab Government buildings and leading to an estimated reduction in annual electricity consumption by 2.63MWh. PEECA has also been working to replace 250,000 fans in 20,000 public education institutions and close to 20,000 fans in public health facilities. In 2017, PEECA also initiated a project for integrating solar PV systems in public institutes in Punjab.

1.11 National Energy Conservation Policy 2006

The National Energy Conservation Policy 2006 provides broad guidelines to enhance end-use energy efficiency in various energy consuming sectors of the economy. Few initiatives outlined in the policy are mentioned below:

Policy initiatives:

- Formulate and enact comprehensive legislation on Energy Conservation and Management
- Development of energy conservation codes and standards
- Create public awareness through training, education, information dissemination and demonstration
- Declare energy conservation as an industry to allow fiscal and financial incentives to be available for Energy Conservation pursuits
- Institution of National Awards for outstanding work on energy conservation

Sectorial initiatives:

- Industry
  - Introduce and initiate energy audits in industries and promote targeted technical services
  - Encourage and promote better housekeeping and implementation of low cost fast payback energy conservation measures in industry
  - Promote energy efficiency combustion process instrumentation and control and metering practices in industries
  - Develop MIS and Energy Efficiency Potential indices
  - Promote energy efficiency conservation, modernization and revamps.

- Power
  - Support deployment of cost effective energy efficient technologies
  - Promote co-generation as a means to plug energy deficits
  - Collaborate with WAPDA and utilities to devise and enforce efficient administrative and technical measures for promoting Demand Side Management and conservation projects
  - Collaborate with power utilities to reduce T&D losses

The policy also outlines initiatives to be implemented in the transport, building, agriculture, renewable energy sectors and implementation and monitoring measures.

1.12 Key Energy Efficiency Policies in Pakistan Vision 2025

Pakistan's Vision 2025 (Pillar – IV) is focused on the energy-water and food security. While addressing the energy sector, the Vision document emphasizes ensuring uninterrupted access to affordable and clean energy. The main energy efficiency and conservation related goals constituted in the Vision 2025 for Energy sector are[1]:

- Maximize distribution efficiency and cut wasteful losses through investment in transmission and distribution infrastructure and effective enforcement of controls;
- Focus on demand management and conservation to ensure prioritization in allocation, elimination of wasteful use, incentives to use more energy efficient equipment and appliances and achieve better balance between peak and off-peak hours.

1.13 Pakistan's Nationally Determined Contributions

Globally, Pakistan adopted the international climate agreement at the U.N. Framework Convention on Climate Change (UNFCCC) Conference of the Parties (COP21) in Paris in December 2015. Pakistan's Ministry of Climate Change in collaboration with other ministries has outlined post-2020 climate actions intended to take under the Paris agreement[2] Internationally, three main components outlined in this agreement are (a) holding the increase in global average temperature below 2°C (b) pursue efforts to limit the increase to 1.5°C (c) net zero emission in the second half of the century.

Pakistan's NDC is strategically aligned with "Vision 2025" and is based on sectorial growth in accordance with various line ministries and entities' plans and policies. The NDC document submitted by Government of Pakistan has also incorporated the major projects such as China Pakistan Economic Corridor (CPEC), projecting the future economic growth and the subsequent GHG emissions.

The historical GHG emission trend of Pakistan has been fairly consistent with an average GDP growth rate of 4%. Considering the historical trend, projections for GHG emission for 2030 is estimated as 1603 MT of CO_2 equivalent and same is shown in figure below.

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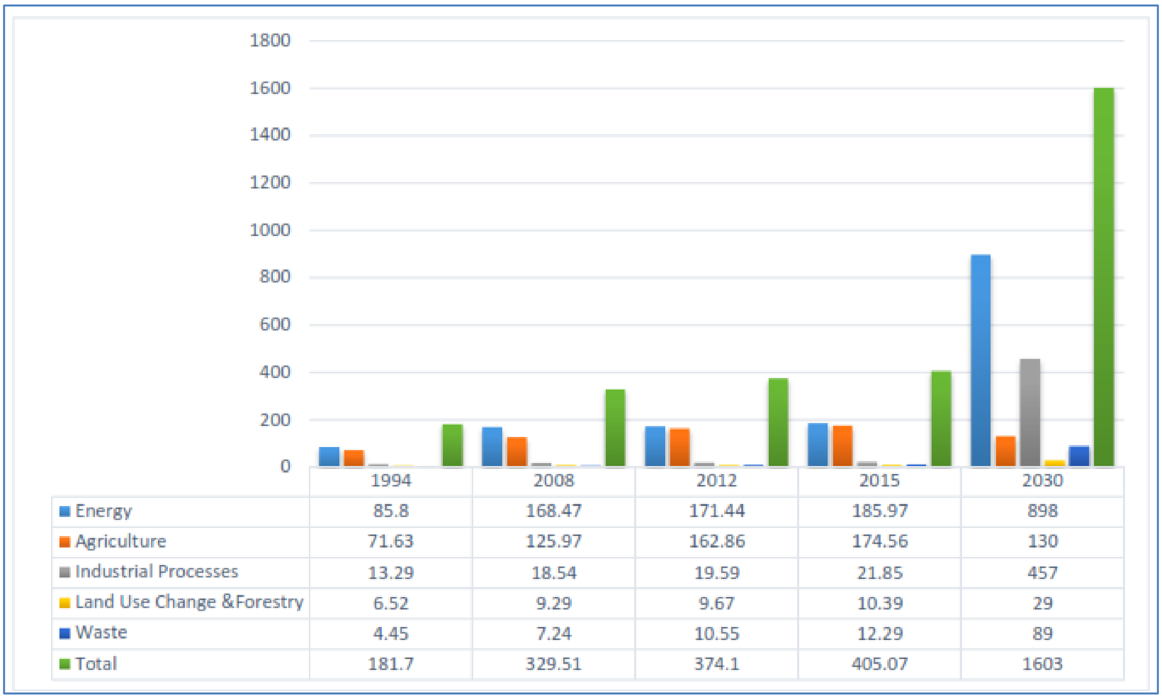
[1] source: http://pc.gov.pk/web/vision

[2] These post-2020 climate action intended to take under the Paris agreement are known as Intended Nationally Determined Contributions (INDCs).



	1994	2008	2012	2015	2030
🟦 Energy	85.8	168.47	171.44	185.97	898
🟧 Agriculture	71.63	125.97	162.86	174.56	130
◼ Industrial Processes	13.29	18.54	19.59	21.85	457
🟨 Land Use Change &Forestry	6.52	9.29	9.67	10.39	29
🟦 Waste	4.45	7.24	10.55	12.29	89
🟩 Total	181.7	329.51	374.1	405.07	1603

Figure 1.14: Sector wise GHG emission trend of Pakistan
Source: CPEC contribution in GHG emission in Pakistan

From 1994-2015, the overall increase in emission is approximately 123% with 90% of emissions solely attributed to energy and industrial sector (See Figure 1.14). The emission profile is dominated by energy sector with the major share of 46% out of total emission, and there will be significant growth in its share in future.

With a projected population growth rate of 2.4%, Pakistan's population is expected to increase to 95.5 million by 2025 and 102 million by 2030. In 2014, Pakistan's per capita oil equivalent use was reported to be 482 kg (including traditional biomass fuels) which is one of the lowest ranked across the world. Similarly, Pakistan greenhouse gas emissions are very low; between 0.1-4.0 tonnes CO_2 equivalent per capita/year. However, considering the expected population growth along with economic development, the future emission may increase exponentially.

The government of Pakistan sets GDP growth target of 7% till 2025 in "Vision 2025", and same for an extended period until 2030. The addition of 25,000 MW of electricity in the grid is envisaged by 2025, with major policy shift in the energy mix for renewable energy. The currently planned addition of 10,400 MW is in the pipeline to eliminate the current demand-supply gap by 2018. The projected emissions for the GDP growth through energy sector by 2030 are calculated as 898 MT CO_2-equivalent out of the total 1,603 MT CO_2-equivalent.

Pakistan's vulnerability to adverse climate change is well established. The Global Climate Risk Index 2017[3] has categorized Pakistan in top ten severely climate-affected countries in the world, with imminent adverse impacts. National Disaster Management Authority (NDMA) assessment revealed that climate catastrophe resulted in an economic loss of USD 4 billion.

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[3] Global Climate Risk Index 2017/https://germanwatch.org/sites/germanwatch.org/files/publication/16411.pdf

The floods (2010-2014) resulted in losses of USD 18 billion, 38.12 million people were affected, 3.45 million houses damaged, and 10.63 million acres of crops destroyed[4]. In addition, federal expenditure related to climate was between 5.8 and 7.6% of total expenditure in 2015[5].

The scenarios based economic analyses by the Ministry of Climate Change shows that:

- 20% reduction is projected emission by 2030 requires an overall investment of USD 40 billion
- A reduction of 15% GHG emissions requires USD 15.6 billion and reduction of 10% requires USD 5.5 billion.

Most of these investments will be channelized toward the mitigation; concentrated efforts will be required for energy and agriculture sector. The projected emissions share of energy sector in 2030 is more than 50% (898 out of 1,603 MT CO_2-equivalent) and it has the most potential for mitigations and adaptation in Pakistan. Therefore, it is estimated that Pakistan's adaptation efforts require between US$ 7 to US$ 14 billion/annum. More specifically in the energy sector, the focus of these mitigations and adaptations will be directed towards energy efficiency and conservation measures.

1.13.1 Pakistan NDC Statement

Pakistan intends to reduce up to 20% of its 2030 projected GHG emissions subject to availability of international grants to meet the total abatement cost for the indicated 20% reduction, amounting to about US$ 40 billion at 2016 prices.

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[4] http://www.ndma.gov.pk/

[5] http://www4.unfccc.int/Submissions/INDC/Published%20Documents/Pakistan/1/Pak-INDC.pdf

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."

Organizations 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 organizations, energy management is "business as usual".

Successful energy management needs 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 organization. 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

As per National Energy Efficiency and Conservation Act 2016, "energy audit" means an extermination of any energy consuming project about the way the energy is generated, transmitted, distributed or used there and identification of areas where energy waste can occur for improving energy efficiency and where scope for improving energy use efficiency may be possible.

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 utilization 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	Longer time frame, say 15–30 days
Uses readily available data for quick analysis and results are general	Uses operating data, detailed observations, measurements, energy and mass balance to assess energy performance
Focus on common opportunities for energy efficiency	More specific recommendations for energy improvements covering all areas
Economic analysis is mostly limited to calculation of simple payback period	Economic analysis may include internal rate of return, net present value, life cycle cost, as well as simple payback period
Broad recommendations	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 for 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.

2.4.1 Step-by-Step Guidance for Detailed Energy Audit

Step	Plan of Actions	Results
	a) INITIATING THE AUDIT	
Step1	• 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	
Step2	• 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.
Step3	• 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) EXECUTINGTHE AUDIT	
Step4	• 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.
Step5	• 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. • Break-down of energy consumption by department/section as a pie-chart. • Baseline energy consumption.
Step6	• 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 (24hours) 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.
Step7	• Analyse use of energy, material and water use.	• Energy & material balance and assessment of energy losses/wastes. • Water conservation opportunities.

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

2.4.2 Audit Criteria and Scope

These define purpose, depth and methodology to be adopted by energy audit or for the given audit. In case of mandatory energy auditor 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).

2.4.2.1 Sample Scope of Work (commercial buildings)

The energy audit consultancy organization, 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. Heating Ventilation & Air-Conditioning Systems

The equipment under HVAC System would cover:
- Centrifugal chillers
- Auxiliary equipment: chilled water and cooling water pumps
- Distribution & Utilization system (Air Handling Unit)

The scope of the study would include:
- Estimation of actual TR generation by the chillers.
- Measurement of power consumption and estimation of specific power i.e., kW/TR for chillers
- Measurement of power consumption and evaluation of operating efficiencies for the other auxiliary consuming equipment's.
- Study operational features of chiller compressors such as temperatures, pressure control
- Study of auxiliary components for energy efficiency and their impact.
- Study of distribution network for temperature drop, pressure drop and insulation
- Monitoring of operating parameters vis-à-vis desirable parameters in user locations
- User end area cooling load distribution analysis (as feasible) to arrive at energy conservation measures
- Application potential for various energy saving retrofits

B. Pumping System

The study of pumps would cover water pumps:

- Flow and head measurement of water pumps by using sophisticated energy audit equipment
- Measurement of power parameters (kW, kVA, pf, frequency, current, voltage)
- Evaluation of operating efficiency of pumps
- Application and matching of drive
- Application of flow control methods
- Application of retrofit for energy savings

C. Cooling Towers

The cooling tower efficiency will directly affect the performance of plant equipment, which leads to higher energy consumption. In view of this a study will be under taken to analyze;

- The present approach and range of the cooling tower against its designed values
- Cooling tower optimization along with suitability of retrofits such as automatic temperature controller,
- Cooling water user areas, etc. will be looked into.

D. Fans & Blowers

The study of fans & blowers would cover:

- Flow and head measurement by using sophisticated energy audit equipment.
- Measurement of power parameters (kW, kVA, pf, frequency, current, voltage)
- Evaluation of efficiency of fans & blowers
- Application and matching of drive
- Application of flow control methods
- Application of retrofit for energy savings

E. Compressed Air Systems

The scope of compressed air system study would cover:

- Free air deliver (FAD) assessment of working compressors
- Operation of inter / after coolers
- Loading and unloading practices
- No-load test (leakage test) to quantify leakage quantity – During plant shut down period
- Compressed air distribution network survey – for pressure drops (reference plant pressure gauges)
- Application potential for energy saving retrofits

The above areas will be studied to identify opportunities for energy saving.

F Electrical Systems

The scope of electrical systems covers

- Transformer Load Management
- Distribution Losses
- System voltage optimization
- Power factor analysis
- Harmonics study

An in-depth study of the energy losses in the cable system would indicate the measures to be taken for minimizing the energy losses in the cables and the overall distribution losses (percentage).

G Electric Motor & Drives

The scope of electric motors and drives covers motor loading analysis and drive matching by using power analyzer. Operating parameters such as kW, kVA, pf, Voltage, Current and Frequency will be measured. Based on the above analysis the following practically implementable energy conservation measures recommendations will be made.

- Proper sizing of motor
- Use of energy efficient motors by replacing oversized and inefficient motors
- Possibility of operating motors in star mode wherever motors are under loaded
- Reactive power compensation for motors operating at low PF
- Application speed controlling devices & smooth starting devices
- Energy efficient transmission

H. Lighting System

Examine present lighting system in all areas and assess lighting load (lighting inventory, lighting equipment, type, rating, numbers and corresponding control gears)

- Measure lux levels at various locations and analyze lighting performance indices like lux/m2, lux/watt, lux/watt/m2 and compare with norms
- Evaluate possibilities to reduce energy use by incorporating energy efficient lighting system, equipment's including layout changes
- Explore Energy Conservation Options (ENCON) in lighting system.

I Others

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

2.4.3 Initial Site Visit and Preparation

An initial site visit may be planned before the audit to give the energy audit or an opportunity to meet the top management and other department heads, to familiarize with the site, and to assess the procedures necessary to carryout 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
- Identifylistofparameterstobemeasuredandtheinstrumentsneededduringtheenergy audit
- Create awareness through a meeting/programme.

2.4.4 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.

2.4.5 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.

2.4.5.1 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 1–3years)
- Production data(1–3years)
- 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 utilization
- Amount and type of input materials used
- Electricity consumption
- Steam consumption
- Water consumption
- Fuel consumption
- Efficiencies/yield
- Type and quantity of waste generated
- Percentage rejection/reprocessing

2.4.5.2 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.

2.4.5.3 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.

2.4.6 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–3 and 1(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
- Digital manometer
- Vane anemometer
- Tachometers- Stroboscopic tachometer
- Ultrasonic Flow Meter
- Anemometer
- Hygrometer (Humidity measurements) Temperature Probe
- Ultrasonic stream trap tester Thermal imaging devices Miscellaneous instruments–leak detectors, pH meter and TDS meter

2.4.7 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:

2.4.7.1 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.

2.4.7.2 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.

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

2.4.8 Identification of Energy Conservation Opportunities

2.4.8.1 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.

2.4.8.2 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.

2.4.8.3 Energy distribution

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

2.4.8.4 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.

2.4.8.5 Technical and Economic Feasibility

The technical feasibility addresses the following issues:

- The technology availability, space, skilled man power, 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).

2.4.9 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 house-keeping 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.

2.4.10 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.

2.4.11 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 hardcopy. The report is authorized by the certified energy auditor or accredited energy auditor (for designated consumers).

2.4.11.1 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 Flowchart 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 2.1shows summary of baseline energy and resource consumption. 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 Savings (Fuel & Electricity) (kWh/MT or KL/MT)	Annual Savings Rs. Million	Capital Investment (Rs. Million)	Simple Payback period (Years)
1.					
2.					
3.					
	Total				

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 prioritize and implement various ENCON measures and tool such as ISO 50001 is highly useful.

2.5.1 Role of ESCO

ESCO is an organization 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.

2.7.1 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 Tonnes or Kilo litres. 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 Bench marking 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 bench marking 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 bench marking 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:

Power plant	**Heat rate, kCal/kWh Power produced**
Cement plant	kWh/MT clinker or cement produced
Textile unit	kWh/kg yarn produced
Paper plant	kWh/MT, kCal/kg, paper produced
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/Nm3 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

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.

2.9.1 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.

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

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).

$$Reference\ year\ equivalent\ = Reference\ year\ energy\ use \times Procudtion\ factor$$

The plant energy performance is calculated using the following relation:

$$Plant\ Energy\ Performance = \frac{Reference\ year\ equivalent - current\ year\ energy}{Reference\ year\ equivalent} \times 100$$

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.

Example:

The integrated paper plant has produced 119366MT of paper during the year 2015-16. The management has implemented various energy conservation measures and had reduced the specific energy consumption from 53GJ/tone of product to 50GJ/tone 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=119366MT
Reference year specific energy consumption=53GJ/tonne of product
Assessment year production=124141MT
Assessment year specific energy consumption = 50GJ/tonne of product

$$Production\ Factor = \frac{Assessment\ Year\ Production}{Reference\ Year\ Production}$$

Production factor = (124141/119366) = 1.04

$$Reference\ year\ energy\ consumption, GJ = Reference\ year\ Specific\ Energy\ Consumption\ \left(\frac{GJ}{MT}\right) \times Reference\ year\ production, MT$$

=53 x 119366 = 6326398 GJ

$$Assessment\ Year\ energy\ consumption, GJ = Reference\ year\ Specific\ Energy\ Consumption\ \left(\frac{GJ}{MT}\right) \times Assessment\ Year\ Production\ , MT$$

=50x124141=6207050GJ

$$Reference\ Year\ equivalent\ energy\ use\ , GJ = Reference\ Year\ energy\ consumption\ , GJ \times Production\ Factor$$

=6326398GJx1.04=6579454 GJ

$$Plant\ energy\ performance\ \% = \frac{Reference\ year\ equivalent\ energy - Assessment\ year\ energy}{Reference\ year\ equivalent\ energy} \times 100$$

= ((6579454- 6207050)/6579454) x 100 =5.66%

Plant energy performance = 5.66

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

Example:

A manufacturing industry plans to improve its energy performance through implementation of an energy conservation scheme. After implementation, calculate the Plant Energy Performance (PEP) with 2017-18 as the reference year. What is your inference?
Given that:

- The current year (2018-19) Annual Production – 28,750 T ,
- Current year (2018-19) Annual Energy Consumption– 23,834 MWh,
- Reference year (2017-18) production - 34,000 T,
- Reference year (2017-18) Energy consumption - 27,200 MWh.

Production factor, current year (PF) = 28750/34000 = 0.846

Ref year equivalent energy (RYEE) = Ref Year Energy Use (RYEU) x PF
= 27,200 x 0.846= 23011MWh
PEP = (RYEE – current year energy)/RYEE = (23011 – 23834)/23011
= (-) 0.0369 ie (-) 3.7 %

Since the PEP is negative, it implies that the energy conservation measure did not yield reduction in energy consumption, action to be taken to improve the plant performance.

2.9.2 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 Maximizing 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
- Maximize 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 2.1.

Table 2.1: 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 them or. Instant measurements can be taken with hand-held meters, while more advanced ones facilitates cumulative readings with print outs at specified intervals say every 1/2hr 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 standstill 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 photocell 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 in built 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.

No.	Name of the Instrument	Features and Typical Applications
6.	**Thermometer** 	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 to175°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.
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.
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 diameter of pipe). This non-contact flow measuring device uses Doppler effect/ Ultrasonic 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.

No.	Name of the Instrument	Features and Typical Applications
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 inducts can be measured using a pitot tube falonwds.an inclined manometer for further calculation of the principle is based on measuring the differential
15.	**Conductivity Meter** 	This instrument is used for spot analysis of the amount of total dissolved solids (TDS) in water especially in case of boiler blowdown. An accurate measurement of TDS is required to maintain blow down rate in boilers and optimize energy consumption. TDS meter measures the conductivity of solution then converts that value to an equivalent TDS reading.
16.	**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.

No.	Name of the Instrument	Features and Typical Applications
17.	**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 not measure the size of the leak.
18.	**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.

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 organization'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 CO_2 emissions to the environment, and the organization thereby contributes its part to addressing the climatic change objectives of the country.

Despite these opportunities for energy savings and efficiency improvements, organizations 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. As per one of the definitions: ISO 50001 defines EnMS as "set of interrelated or interacting elements to establish an energy policy and energy objectives, and processes and procedures to achieve those objectives."

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 world-wide. 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 organization take appropriate actions to overcome barriers in implementing practical energy saving measures, International Organization for Standardization (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 overtime. 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 inter related 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.

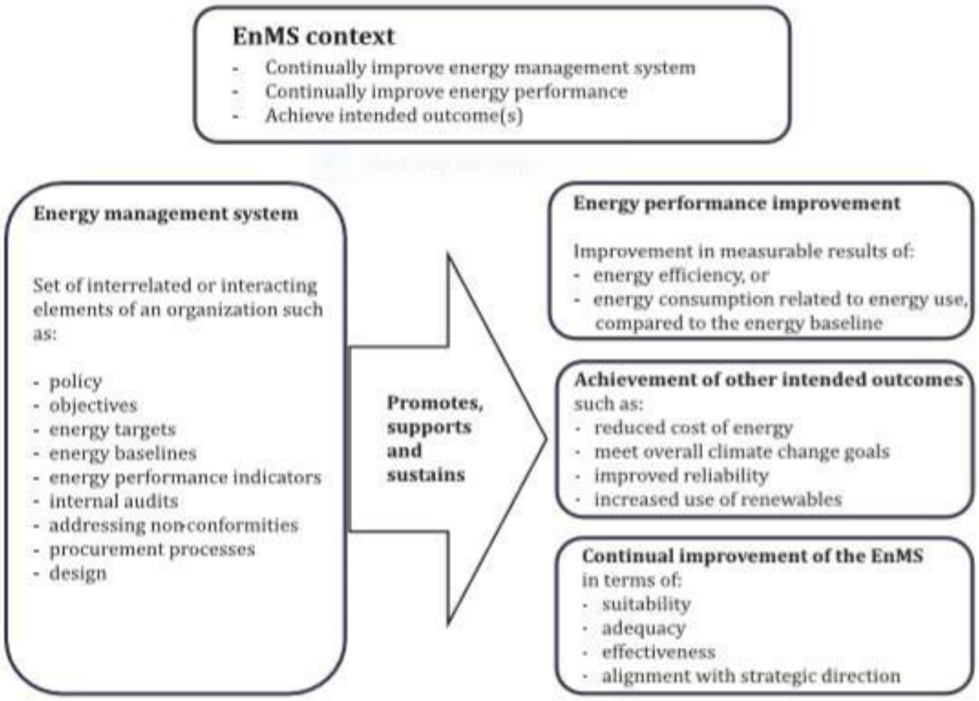


Figure 3.1–Relationship between EnMS and Energy Performance

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.

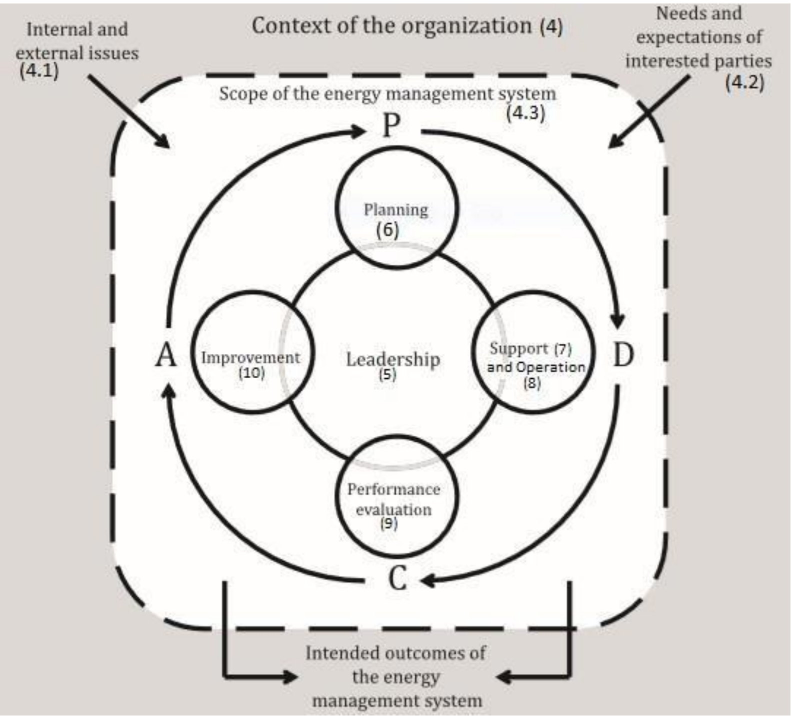


Figure 3.2 PDCA cycle

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 50001will 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 50001comparable 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 so brings risk management approach—risk management, risk analysis in energy management system. Salient feature of HLS:

- A common structure for all Standards (ISO 9001, ISO14001) 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:

1. 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;
2. better integration with strategic management processes;
3. clarification of language and document structure;
4. stronger emphasis on the role of top management;

5. adoption of context order for the terms and their definitions in Clause 3 and update of some definitions;
6. inclusion of new definitions, including energy performance improvement;
7. clarification on exclusions of energy types;
8. clarification of "energy review";
9. introduction of the concept of normalization of energy performance indicators[EnPI(s)] and associated energy baselines [(EnB (s)];
10. addition of details on the energy data collection plan and related requirements (Previously energy management plan): and
11. clarification of text related to energy performance indicators [EnPI(s)] and energy baselines [EnB (s)].
12. addition of details on the energy data collection plan and related requirements (previously energy measurement plan);
13. 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 standards 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 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 inter-changeable. "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.

Chapter 4 Financial Management

4.1 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 atleast 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.

4.2 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 high lighting 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 house-keeping 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

- To retrofit 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

4.2.1 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.

4.2.1.1 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 behavior.

This criterion helps complete technical evaluation. Once the list of investment opportunities is shortlisted based on the above criteria the investments required and savings appraisal needs to be done.

4.2.1.2 Investment Appraisal Criteria

Energy Manager has to

- Identify how cost savings arising from energy management contribute to profits,
- How energy projects are comparable to the 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 core activities
- Enhancing the quality of service or customer care delivered.
- Protecting the environment

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 is applied to all its other investments.

4.3 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 proposal cost?
- How much money will be saved by implementing the proposal?
- Whether alternate proposals costless 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.

4.3.1 Profit, Revenue and Costs

Business's prime goal is to maximize profits, which occur when difference between total revenue and total cost is the highest.

$$Profit = Total\ revenue - Total\ cost$$

Energy specialists have no control on factors impacting revenue. However, energy specialists can aid in cost minimization by

- identifying and evaluating energy conservation measures 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 formulas related to preparation of income statement are given below:

$$\begin{aligned}&Earnings\ before\ Interest, Taxes, Depreciation\ and\ Amortization\ (EBITDA)\\&= Operating\ income - Operating\ expenses\end{aligned}$$

$$\begin{aligned}&Earnings\ before\ Interest\ and\ Taxes\\&= EBITDA - Depreciation\ expense - Amortization\end{aligned}$$

$$EBIT = Operating\ income - Operating\ expense + Non - operating\ income$$

$$Earnings\ Before\ Taxes\ (EBT) = EBIT - Interest$$

$$Earnings\ after\ Taxes\ (EAT) = EBT - Income\ Tax$$

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 insensitivity/risk analysis of the projects.

The subsequent sections will highlight how each cash flow element effect investment choices.

Example 1: Estimating EBIT

Sales Revenue	**PKR 300,000**
Cost of goods sold	PKR 5,000
Depreciation	PKR 8,000
Selling expenses	PKR 2,000
Non-operating income	PKR 500

$$\begin{aligned}EBIT &= Sales\ revenue - (cost\ of\ goods\ sold + depreciation + selling\ expenses)\\&\quad + Non - operating\ income\\EBIT &= 300{,}000 - (5{,}000 + 8{,}000 + 2{,}000) + 500\end{aligned}$$

4.3.1.1 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, installments 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 etc. 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 2 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 PKR 900,000, the annual output is 219MWh and the maintenance cost is PKR 30,000 per annum. The cost of producing each unit of electricity is 3.50PKR/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 (PKR)
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 table above, it can be seen that the fixed costs represent 18.4% of the total cost. In fact, the annual electricity output of 219 MWh assumes that the plant is operating with an average output of 25kW (assuming 24hours, 365days operation). If this output were increased to an average of 45kW, then the fuel cost would become PKR 6,898,500 (assuming unit cost of generation remains the same), with the result that the fixed costs would drop to 11.3% 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.

4.3.1.2 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:

Thickness of insulation (in inches)	Marginal cost (PKR)	
	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 thickness of insulation to be installed.

Solution: The proper amount is where marginal cost is equal to marginal cost savings. This occurs between the eight hand ninth inch of insulation. Therefore, if the home owner installs the eighth inch, the cost savings are greater than the investment cost. 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 analyze solar collector by square foot than by 32ft2 collector.

The concept of equating costs with savings can also be estimated using break-even analysis concept.

4.3.1.3 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.

$$UC_{uti} \times W_{av} \times n = FC + (UC_{prod} \times W_{av} \times n)$$

Where,

UCutil unit cost per kWh of energy bought from utility (PKR/kWh)
UCprod unit cost per kWh of produced energy (PKR/kWh)
FC fixed costs (PKR)
Wav average power output (or consumption) (kW)
Number of hours of operation (hours)

Example 4: Assessing break-even point

If the electricity bought from a utility company costs an average of PKR 4.5/kWh, the break -even point for the generator described in Example 2, when the average output is 25kW is given by:

$$4.5\times25\times n = (900{,}000+150{,}000) + (3.5\times 25\times n)$$

$$n = 42{,}000$$

If the average output is 45kW, the break-even point is given by:

$$4.5\times45\times n = (900{,}000+150{,}000) + (3.5\times 45\times n)$$

$$n = 23{,}324$$

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 utilized.

(Moreover if the loading of DG set is improved to 75%-80% of rated capacity, unit cost of generation will reduce as specific energy generation of the DG set will improve. Thus in the above example, there will be further reduction in break- even time of the project)

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 PKR 1,000,000 asset is depreciated at 20% and the marginal tax rate is 40%, the depreciation would be

- PKR 200,000 and the tax cash flow would be PKR 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.

4.4 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)?

4.4.1 How interest charges are calculated.

Two types of interest are normally charged namely simple 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>
<tr><td>Calculation and concept of Simple and Compound Interest</td><td></td></tr>
<tr><td>Simple Interest</td><td>Compound Interest</td></tr>
<tr><td>$S.I. = P \times n \times \frac{r}{100}$</td><td>$C.I. = P \times (1 + \frac{r}{100})^n$</td></tr>
<tr><td>$Total\ Repayment\ Value = P + S.I.$</td><td>$Total\ Repayment\ Value = P + C.I.$</td></tr>
<tr><td>
<table>
<tr><td></td><td></td><td></td><td>$r_{3rd\ yr}$ = (1xr)</td></tr>
<tr><td></td><td></td><td>$r_{2nd\ yr}$ = (1xr)</td><td>$r_{2nd\ yr}$ = (1xr)</td></tr>
<tr><td></td><td>r_{1styr} = (1xr)</td><td>r_{1styr} = (1xr)</td><td>r_{1styr} = (1xr)</td></tr>
<tr><td>P = PKR 1</td><td>PKR 1</td><td>PKR 1</td><td>PKR 1</td></tr>
<tr><td>$FV_{0th\ yr}$ = P = PKR 1</td><td>$FV_{1st\ yr}$ = 1 + r</td><td>$FV_{1st\ yr}$ = 1 + r + r</td><td>$FV_{1st\ yr}$ = 1 + r + r</td></tr>
</table>
</td><td>
<table>
<tr><td>P = PKR 1</td><td>x (1+r)</td><td>x (1+r)</td><td>x (1+r)</td></tr>
<tr><td colspan="2">Amount 1st year end</td><td></td><td></td></tr>
<tr><td colspan="3">Amount 2nd tear end</td><td></td></tr>
<tr><td colspan="4">Amount 3rd year end</td></tr>
</table>
</td></tr>
<tr><td>Where S.I. : Simple Interest
r : Interest rate
n : Repayment period
P : Principal</td><td>Where C.I. : Compound Interest
r : Interest rate
n : Repayment period
P : Principal</td></tr>
</table>

The techniques involved in calculating simple and compound interest are illustrated in Example 5.

Example 5: Calculating Simple and Compound Interest

A company borrows PKR 3,00,00,00 to finance a new boiler installation. If the interest rate is 10% per annum and there payment period is 5 years. Calculate the value of the total repayment and the monthly repayment value assuming (i) Simple interest and (ii) compound interest.

(i) Assuming simple interest:

Total repayment =3,000,000+ (10/100 x 3,000,000 x 5)
=PKR 4,500,000

Monthly repayment = 4,500,000 / (5x12)
= PKR 75,000

(ii) Assuming compound interest

Repayment at end of year 1 = 3,000,000 + (10/100 x 3,000,000)
= PKR 3,300,000

Repayment at end of year 2 = 3,300,000+ (10/100 x 3,300,000)
= PKR 3,630,000

Similarly, there payments at the end of years 3, 4 and 5 can be calculated: Repayment at end of year 3 =PKR 3,993,000

Repayment at end of year 4 = PKR 4,392,300

Repayment at end of year 5 = PKR 4,831,530

Alternatively, the following equation can be used to determine the compound interest repayment value.

Total repayment value $=3,000,000 \times (1+10/100)^5$
= PKR 4,831,530

Monthly repayment = 4,831,530/ (5x12)
= PKR 80,525

It can be seen that by using compound interest, the lender recoups an additional PKR 331,530. Lenders usually charge compound interest on loans.

4.4.2 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 PKR100 deposit will be worth PKR 110 in one year's time. Thus the PKR 110 in one year is a future value equivalent to the PKR 100 present value.

In the same manner, PKR100 received one year from now is only worth PKR 90.91 in today's money (i.e.PKR90.91plus 10% interest equals PKR100). Thus PKR 90.91 represents the present value of PKR100 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:

$$Future\ Value = NPV \times (1+i)^n$$

$$NPV = \frac{Future\ Value}{(1+i)^n}$$

Where,

FV – Future Value
NPV – Net Present Value
i- Interest rate
n – Number of years in 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.

$$FV_n(PKR\ 1) = PV \times FVIF(n\ years, r)$$
$$PV_n(F) = F \times PVIF(n\ years, r)$$

Example 6: Future Value of a Fixed Amount Greater than PKR 1.

A residential customer decides to buy two 1 m^2 solar collector panels at PKR 20,000 each and has the option of paying PKR 20,000 now or PKR 30,000, in 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 PKR 20000, in 5 years from now, is calculated as follows

Method 1: using the formula

$$Future\ Value\ (FV) = NPV \times (1+i)^n$$

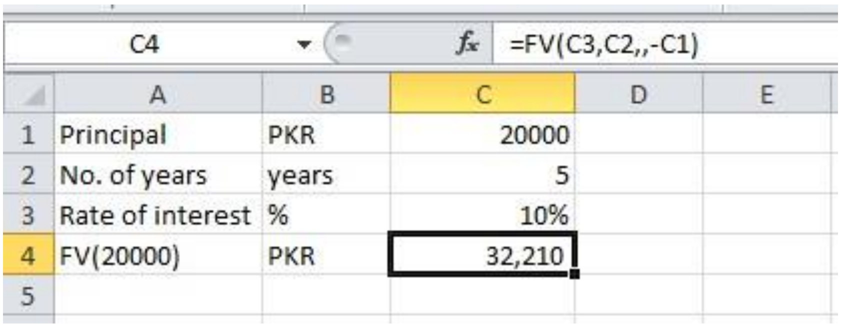
$$FV = 20{,}000(1+0.1)^5 = PKR\ 32210$$

Method 2: using FVIF tables (Appendix 2 is given at the back of this module).

FV5 (PKR 20,000) = 20000xFVIF (5 years, 10%)
= 20000 x 1.610
= PKR 32210

Method 3: using MS Excel.

MS Excel Formula=FV (rate, no. of periods, principal, 1)



C4 =FV(C3,C2,,-C1)

	A	B	C	D	E
1	Principal	PKR	20000		
2	No. of years	years	5		
3	Rate of interest	%	10%		
4	FV(20000)	PKR	32,210		
5					

FVIF (5 years, 10%) is obtained from Appendix 2. Thus, the future value of the PKR 30,000 payment in 5 years is less than the PKR 20,000 payment now, and the business could wait 5 years and pay PKR 30,000 to minimize the cost. Instead of paying PKR 20,000 now, the business could put the PKR 20,000 in a bank account drawing 10% interest per year. After 5 years, the business would have PKR 32,210 in the account and could pay the PKR 30,000 and use the remaining PKR 2,210 for other purpose. If the PKR 20,000 is paid now, the business in effect loses PKR 2,210.

4.4.2.1 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 was PKR 670 per Million Metric BTU in 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:

$$Future\ Value\ (FV) = NPV \times (1 + i)^n$$

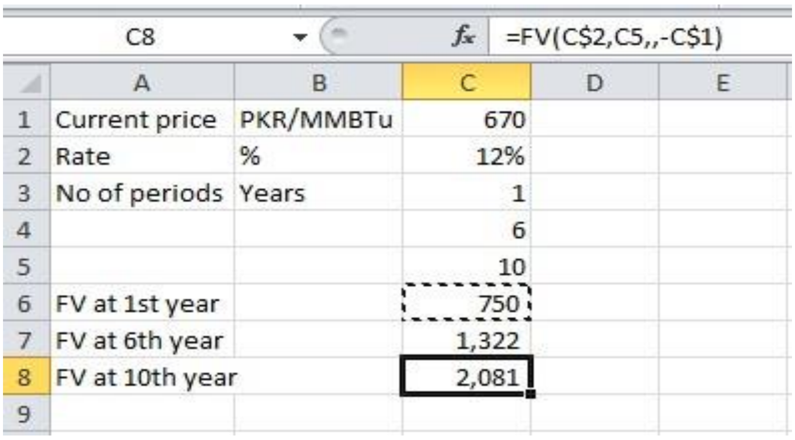
Particulars	Value
FV of NG at end of	PKR
1 year	750
6 years	1,322
10 years	2,081

Method 2: Using Formula: Price of natural gas after years=Price n now x FVIF (nyear,12%)

Solution:

Particulars	Value
Price of natural gas after 1 year	=PKR670x1.1200=PKR 750
Price of natural gas after 6 years	=PKR 670x1.9738=PKR 1,322
Price of natural gas after 10 years	=PKR 670x3.1058=PKR 2,081

Method 3: Using MS Excel Formula: FV (rate, no. of periods, principal, 1)



C8 =FV(C$2,C5,,-C$1)

	A	B	C	D	E
1	Current price	PKR/MMBTu	670		
2	Rate	%	12%		
3	No of periods	Years	1		
4			6		
5			10		
6	FV at 1st year		750		
7	FV at 6th year		1,322		
8	FV at 10th year		2,081		
9					

4.4.2.2 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 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.

$$FVA_n(PKR\ 1) = (1+r)^{n-1} + (1+r)^{n-2} + \cdots + (1+r)^1 + PKR\ 1$$

Where,

FVAn(PKR1)=Future value of an annuity of PKR 1 after paying for n time periods at ‘r’ rate of interest.

$$FVA_n(M) \times FVIF(n\ years, r)$$

Where,

FVAn (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

FVIFa (n years, r) =Future value of an annuity of PKR1, 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 PKR 1peryear

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) and 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 PKR5 per kilowatt hour (kWh), and the interest rate is 8%.

Method 1: Using formula

$$FVA_n\ (PKR1) = 11826 \times \{(1+0.08)^3 + (1+0.08)^2 + (1+0.08)^1 + 1\}$$

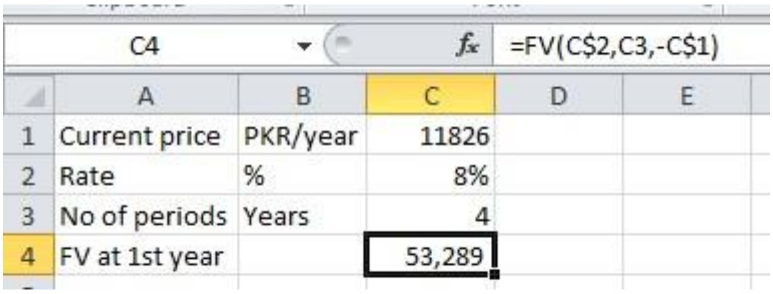
Method 2: Using FVIFAppendix2:

FVAn(M) =MxFVIFa(4years, 8%)

Particulars	Units	Value
Current wattage of bulb	W	300
Replace with	W	30
Electricity usage hours per year	h/yr	8,760
Electricity savings per year	Wh/yr	2,365,200
1kWh	Wh	1,000
Savings in electricity	kWh/yr	2,365.2
Cost of electricity	PKR/kWh	5
Cost savings per year	PKR/yr	11,826
Thus, the savings associated with this project form an annuity of PKR 11826 per year.		

Particulars	Units	Value
Annuity per year	PKR/yr	11,826
Interest rate	%	8
Future value at end of	years	4
Future value of annuity at end of 4 years	PKR	53,289

Method 3: MS Excel Formula=FV (rate, no. of periods, M)



C4 =FV(C$2,C3,-C$1)

	A	B	C	D	E
1	Current price	PKR/year	11826		
2	Rate	%	8%		
3	No of periods	Years	4		
4	FV at 1st year		53,289		

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 PKT 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:

$$PVA_{n_0}(PKR\ 1) = PVIF(1\ year, r) + PVIF(2\ year, r) + \cdots + PVIF(n\ year, r)$$

Where,

PVAn0 (PKR1)=Present value of an annuity of PKR1 for n time periods at ‘r’ rate of interest.

PVIF=Present Value interest factor (the Present Value of PKR1) 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 bulb so of a certain wattage with LED bulb so of a lower wattage in every hallway of a hotel. These bulbs have an expected life of 8 years, and will save PKR1300 per year for the 8-year period. The interest rate is 6%.

Find: The present value of the cost savings.

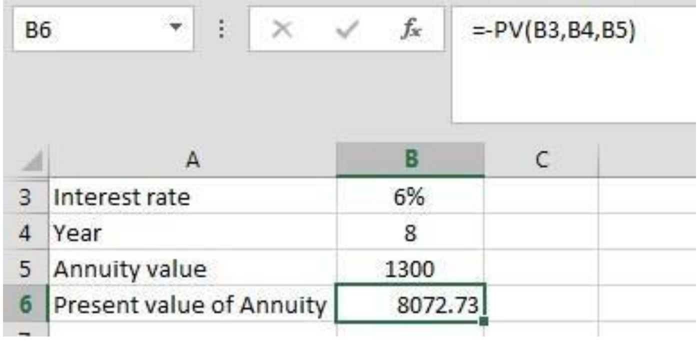
Solution:

Method 1: Using PVIF Factor (Appendix1)

The cost savings form an annuity of PKR1300 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(PKR)	PVIF	Present value(PKR)
1	1300	0.9434	1,226.42
2	1300	0.8900	1,157
3	1300	0.8396	1,091.48
4	1300	0.7921	1,029.73
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	8,072.87

Method 2: Using MS Excel Formula:



B6 =-PV(B3,B4,B5)

	A	B	C
3	Interest rate	6%	
4	Year	8	
5	Annuity value	1300	
6	Present value of Annuity	8072.73	

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 (12h/d, Monday through Saturday) in an area of 25000ft2 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 PKR5 per kWh and the contract ensures the same cost for the next 5 years, after which it will increase to PKR 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:

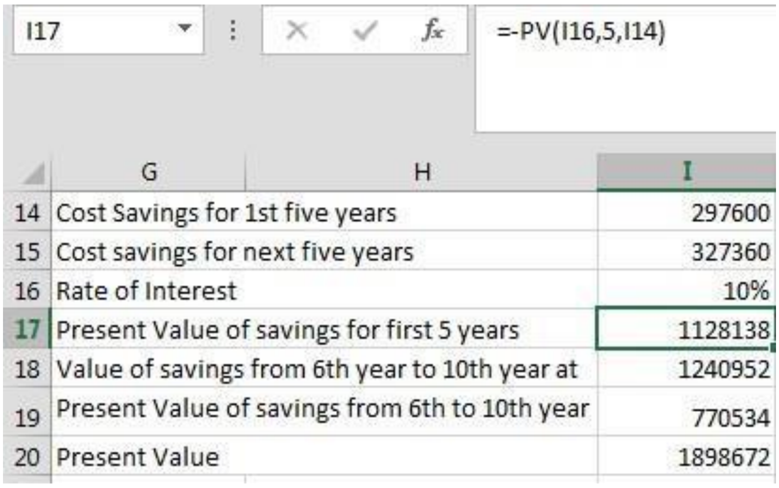
Parameter	**Unit**	**Value**
Floor area of store	ft^2	25000
Business hours per year	h/yr	3720
Total no. of light fixtures at store	nos.	400
No. of bulbs in each fixture	nos.	4
Wattage of each bulb	W	40
Cost of electricity for first 5 years	PKR/kWh	5
Cost of electricity for next 5 years	PKR/kWh	5.5
No. 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	PKR/yr	297600
Cost savings for next 5 years	PKR/yr	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(PKR)**	**PVIF(Appendix1)**	**Present Value(PKR)**
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:



I17

=-PV(I16,5,I14)

	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

4.5 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 atleast 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.

4.5.1 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:

$$Simple\ Payback\ Period = \frac{Capital\ cost\ of\ project\ (PKR)}{Net\ annual\ cost\ savings\ (PKR)}$$

Example 11: Calculating pay-back period.

A new small cogeneration plant installation is expected to reduce a company's annual energy bill by PKR 486,000. If the capital cost of the new boiler installation is PKR 2,220,000 and the annual maintenance and operating costs is PKR 42,000, the expected payback period for the project can be worked out as follows.

Solution:

$$Simple\ Payback\ Period = \frac{2{,}220{,}000}{486{,}000 - 42{,}000} = 5\ years$$

According to the payback criterion, the shorter the payback period, the more desirable the project is.

Example 12: Payback Period when savings each year are equal

ASME (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 PKR 320,000 and will generate net after tax savings of PKR 40,000 per year.

Find: The payback period of this investment

Solution:

$$Simple\ Payback\ Period = \frac{320{,}000}{40{,}000} = 8\ years$$

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 12) suppose the annual net cost savings is PKR 40,000 for the first year and will increase 12% each year thereafter, whereas, the original price of the system remains at PKR 3,20,000. Find the pay-back period of this investment.

Solution: Consider the following table.

Table: Payback period with an irregular flow of cost savings

Year	Original Savings (first year)(PKR)	Escalation FVIP 12%	Actual savings For year(PKR)	Cumulative savings at end of year(PKR)
0	40,000	Given	40,000	40,000
1	40,000	1.12	44,800	84,800
2	40,000	1.2544	50,176	134,976
3	40,000	1.4049	56,196	191,172
4	40,000	1.5735	62,940	254,112
5	40,000	1.7623	70,492	324,604

The Table above shows, the total cost savings of the project becomes 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 favors 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 (PKR)	Cash Flow of B (PKR)
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

4.5.2 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:

$$ROI = \frac{Annual\ Net\ Cash\ Flow}{Capital\ Cost} \times 100$$

Limitations

- It does not take into account the time value of money.
- It does not account for the variable nature of annual net cash inflows.

Example 15: Calculating rate of return

A municipality replaced 1,000,40W CFL streetlight bulbs with 25W LED bulbs investing PKR 3,000,000. The life of LED bulbs is 10 years. The annual electricity savings due to replacement of bulbs is 65,700kWh considering 12hrs operation. Assuming electricity cost of PKR 5.0/kWh, annualized yearly savings are PKR 201849 considering interest rate of 10%.The return on investment would be:

$$ROI = \frac{201849}{3{,}000{,}000} \times 100 = 6.73\%$$

4.5.3 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:

$$\frac{Benefit}{Cost} = \frac{Actual\ net\ cost\ savings/Year}{Net\ cost\,\frac{savings}{year}\,need\ to\ recover\ original\ invetsment}$$

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.

4.5.4 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:

$$Profitability\ Index = \frac{Sum\ of\ discounted\ net\ savings}{Capital\ cost}$$

The higher the profitability index, the more attractive is the project.

Example 16: Calculating and comparing profitability index of two different projects

Consider two projects A and B with investment of PKR 30,000 in project A and PKR 35,000 in project B. The assessment of profits indicates project A generates profit of PKR 10,254 and project B generates profit of PKR 10,867 over the life of project tenure. The profitability index can be calculated as given below.

$$Profitabilty\ index\ of\ Project\ A = \frac{30{,}000}{10{,}245} = 0.342$$

$$Profitability\ index\ of\ Project\ B = \frac{35{,}000}{10{,}867} = 0.33$$

This index is a quick tool to consider the better alternative among two different proposed projects.

4.6 Discounted Cash Flow Methods

In order to over-come 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.

4.6.1 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,

$$NPV = \frac{CF_0}{(1+k)^0} + \frac{CF_1}{(1+k)^1} + \cdots + \frac{CF_n}{(1+k)^n} = \sum_{t=0}^{n} \frac{CF_t}{(1+k)^t}$$

Where

NPV=Net Present Value

CFt=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 (PKR)
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 percent. The net present value of the proposal is:

$$NPV = \frac{100{,}000}{1.1^0} + \frac{200{,}000}{1.1^1} + \frac{200{,}000}{1.1^2} + \frac{300{,}00}{1.1^3} + \frac{300{,}000}{1.1^4} + \frac{350{,}000}{1.1^5}$$

$$NPV = 5{,}273$$

Example 18: Calculating NPV

In a cement plant, 16000 liters lubricant/yr is used to manually lubricate grinding equipment gear trains every 2hours. An automatic oil-mist system was proposed by a supplier claiming that his automatic system uses only 600 liters/yr without compromising on lubricating functionality. The gear lubricant costs PKR100/liter. The expected life of the system is 5 years. The system would cost PKR 600,000 to purchase and install. Maintenance costs would be PKR 37,000/yr. The interest rate is 9%. Find the net present value of installing the automatic oil-mist system.

Solution:

Particulars	Unit	Value
Current lubricant usage	lit/yr	16000
Cost of lubricant	PKR/lit	100
Lubricant required in new oil-mist system	lit/yr	600
Life of new system	Yr	5
Capital cost of new system	PKR	6,00,000
Maintenance cost of new system	PKR/yr	37000
Interest rate	%	9
Solution		
Lubricant savings due to new system	lit/yr	15400
Cost savings	PKR/yr	5,40,000

Thus, the cost savings associated with this project for man annuity of PKR 154000/yr for 5years. The present value of this annuity is as follows:		
PV(cost savings)	PKR	59,90,063
PV(maintenance requirement)	PKR	1,43,917
Present value of the purchase of installation and maintaining new system		
PV(all costs of new system)	PKR	7,43,917
Net Present Value (NPV)	PKR	52,46,146
Since NPV>0 the project should be implemented		
Alternate method:		
Net cost savings/yr (Savings–Cost)	PKR/yr	1503000
Present value of net cost savings	Net savings/yrx PVIF a (5 years, 9%)	
	PKR	5846146
Net Present value	PV of (net cost savings- Capital cost)	
	PKR	5,246,146

When analyzing one particular project, the NPV method offers no special advantage. However, the NPV method 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, 18 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 (PKR)	Maintenance cost (PKR/yr)	Cost Savings (PKR)	NPV(PKR)
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.

$$PV = S \times DF$$

Where S – Cash Flow

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%.

Particulars	Project A	Project B
Capital cost in PKR	30,000	30,000
Year	Net annual savings (PKR)	Net annual savings (PKR)
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:

Year	Discount Factor for 8%	Project A		Project B	
		Net Savings (PKR) (b)	Present Value, PKR (a*b)	Net Savings (PKR) (b)	Present Value, PKR (a*b)
0	1	30,000	30,000	30,000	30000
1	0.926	6,000	5,556	6,600	6,112
2	0.857	6,000	5,142	6,000	5,142
3	0.794	6,000	4,764	6,300	5,002
4	0.735	6,000	4,410	6,300	4,631
5	0.681	6,000	4,086	6,000	4,086
6	0.630	6,000	3,780	6,000	3,780
7	0.583	6,000	3,498	5,700	3,323
8	0.540	6,000	3,240	5,700	3,078
9	0.500	6,000	3,000	5,400	2,700
10	0.463	6,000	2,778	5,400	2,500

Method 2: Using M.S. 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 PKR 10,260, while for Project B it is PKR 10,360. 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 rates lightly 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.

4.6.2 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.

$$0 = \frac{CF_0}{(1+k)^0} + \frac{CF_1}{(1+k)^1} + \cdots + \frac{CF_n}{(1+k)^n} = \sum_{t=0}^{n} \frac{CF_t}{(1+k)^t}$$

Where,

CFt cash flow at the end of year "t"
K discount rate
N life of the project

- ***CFt is negative if expenditure >savings***
- ***CFt 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	(100,000)	30,000	30,000	40,000	45,000

The internal rate of return is the value of "K" which satisfies the following equation:

$$100{,}000 = \frac{30{,}000}{(1+k)^1} + \frac{30{,}000}{(1+k)^2} + \frac{40{,}000}{(1+k)^3} + \frac{45{,}000}{(1+k)^4}$$

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:

$$\frac{30{,}000}{(1+0.15)^1}+\frac{30{,}000}{(1+0.15)^2}+\frac{40{,}000}{(1+0.15)^3}+\frac{45{,}000}{(1+0.15)^4}=100{,}802$$

This value is slightly higher than our target value,100,000. So we increase the value of k from 15 percent to16 percent. (In general, a higher k lowers and a smaller k increases the right-hand side value). The right-hand side becomes:

$$\frac{30{,}000}{(1+0.16)^1}+\frac{30{,}000}{(1+0.16)^2}+\frac{40{,}000}{(1+0.16)^3}+\frac{45{,}000}{(1+0.16)^4}=98{,}641$$

Since this value is now less than 100,000, we conclude that the value of k lies between 15 percent and 16 percent. 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 20ft x 17.5ft. 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 airflow velocity through the open door is 500fpm. Steam, which supplies 2100 Btu/kg, is used for heating. The cost of steam is PKR0.5/kg. The cost of the air-lock is PKR 1,770,000 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=1ft^3-°F.

Particulars	**Unit**	**Value**
Door size	ft	20x17.5
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	PKR/kg	0.5
0.0183Btu supplied to 1ft^3 air raises temp by1°F	ft^3-°F	1
Cost of air lock installed	PKR	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

Particulars	**Unit**	**Value**
Heat loss	Btu/min	101199
Heating cost per min of door opening	PKR/min	24.095
Annual cost savings due to installation of airlock	PKR/yr	433,710
Thus, this project yields uniform savings of PKR433,710/yr over its life.		
Proper PVIa (20years, %)		3.920
From Appendix 3, for 20 year period the proper PVIa of 3.92 corresponds to 25% Interest, PVIa of 3.954 corresponds to 26% interest. Since the PVIa needed is equal to 3.920 the exact value of internal rate of return (i) can be interpolated as follows.		

Example 23: Assess project whether it will achieve desired IRR

A proposed project requires an initial capital investment of PKR 20,000. The cash flows generated by the project are shown in the table below:

Year	Cash flow (PKR)
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 (PKR)**	**8% discount rate**		**12% discount rate**		**16% discount rate**	
		Discount factor	**Present value (PKR)**	**Discount factor**	**Present value (PKR)**	**Discount factor**	**Present value (PKR)**
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% and1 6%.

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:

$$Internal\ Rate\ of\ Return = 0.12 \times (0.16 - 0.12) \times \frac{459.5}{(459.5 - (-1{,}508.9))} \times 100$$

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 PKR 500,000, will last 10 years and will result in fuel savings of PKR 150,000 each year. Find the ‘i’ that will equate the following:

PKR 500,000= 150,000 x PV (A= 10 years, i=?) To do this,
Step I: Calculate proper PVIa

$$Proper\ PVI_a = \frac{Cost}{Annual\ savings} = \frac{500{,}000}{150{,}000} = 3.33$$

From PVIa Table in Appendix 3, for 10 years period check PVIa values corresponding to proper PVIa i.e.,3.33. As can be seen from PVIa table, the IRR falls between 27% and 28% with PVIa 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) x3.364/ (3.364+3.269)= 0.275,or27.5percent

4.6.3 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:

$$Modified\ IRR = \sqrt[n]{\frac{\sum_{t=0}^{n} E_t \times (1 + r_{EXT})^{n-t} + R_n}{\sum_{t=0}^{n} A_t \times (1 + r_{EXT})^{-t}}} - 1$$

Where

IRRmod = modified Internal Rate of Return
At = negative Cash Flows at time t
Et = positive Cash Flows at time t
rEXT = reinvestment rate
n = operating life
Rn = remaining value at time n

4.7 Comparison of Project Evaluation Methods

Method	**Needed Information**	**Result**
Capital recovery factor and benefit cost	• Original Cost, • Life of Investment, • Reinvestment 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, • Reinvestment rate, • Net cost savings per year	How much total present value of net Cost savings exceeds (or less than) original
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

Chapter 5 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 risks, normally the charges for financing will be higher. Also, as per them a date 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 are:

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 in this section.

5.1 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.

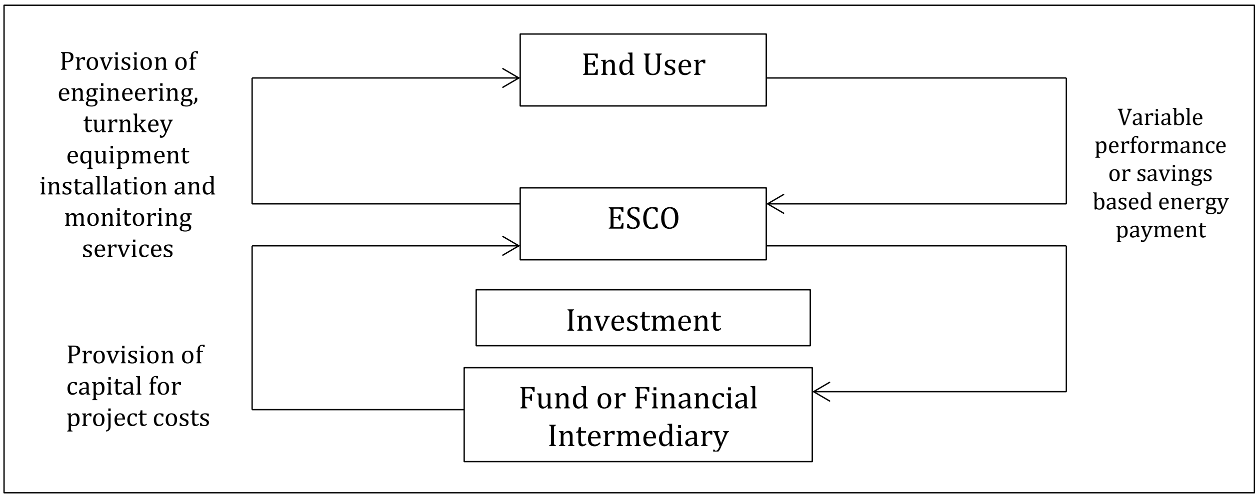
In performance contracting, the end-user (such as an industry, institution, or utility) who is seeking to improve its energy efficiency contracts with ESCO for energy efficiency services and financing. In some contracts, the ESCOs provide a guarantee for the savings that will be realized, and absorbs 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.

5.1.1 What are performance contracts?

Performance contracting represents one of the ways to address some 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 out lay 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.

5.2 Self-Financing Energy Management

Large and capital intensive energy savings project funding or implementation is considered based on external financing and smaller or easily implementable projects are considered by internal teams. To sustain continuous improvement the teams need to been courage 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.

5.3 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:

- Furthering energy efficiency measures
- Activities necessary to create the right climate for successful energy management which do not, by themselves, directly generate savings
- Maintaining or up-grading the management information system.

APPENDIX1: Present Value Tables

Discount factors: Present value of PKR1 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	0.990	0.980	0.971	0.962	0.952	0.943	0.935	0.926	0.917	0.909	0.901	0.893	0.885	0.877	0.870
2	0.980	0.961	0.943	0.925	0.907	0.890	0.873	0.857	0.842	0.826	0.812	0.797	0.783	0.769	0.756
3	0.971	0.942	0.915	0.889	0.864	0.840	0.816	0.794	0.772	0.751	0.731	0.712	0.693	0.675	0.658
4	0.961	0.924	0.888	0.855	0.823	0.792	0.763	0.735	0.708	0.683	0.659	0.636	0.613	0.592	0.572
5	0.951	0.906	0.863	0.822	0.784	0.747	0.713	0.681	0.650	0.621	0.593	0.567	0.543	0.519	0.497
6	0.942	0.888	0.837	0.790	0.746	0.705	0.666	0.630	0.596	0.564	0.535	0.507	0.480	0.456	0.432
7	0.933	0.871	0.813	0.760	0.711	0.665	0.623	0.583	0.547	0.513	0.482	0.452	0.425	0.400	0.376
8	0.923	0.853	0.789	0.731	0.677	0.627	0.582	0.540	0.502	0.467	0.434	0.404	0.376	0.351	0.327
9	0.914	0.837	0.766	0.703	0.645	0.592	0.544	0.500	0.460	0.424	0.391	0.361	0.333	0.308	0.284
10	0.905	0.820	0.744	0.676	0.614	0.558	0.508	0.463	0.422	0.386	0.352	0.322	0.295	0.270	0.247
11	0.896	0.804	0.722	0.650	0.585	0.527	0.475	0.429	0.388	0.350	0.317	0.287	0.261	0.237	0.215
12	0.887	0.788	0.701	0.625	0.557	0.497	0.444	0.397	0.356	0.319	0.286	0.257	0.231	0.208	0.187
13	0.879	0.773	0.681	0.601	0.530	0.469	0.415	0.368	0.326	0.290	0.258	0.229	0.204	0.182	0.163
14	0.870	0.758	0.661	0.577	0.505	0.442	0.388	0.340	0.299	0.263	0.232	0.205	0.181	0.160	0.141
15	0.861	0.743	0.642	0.555	0.481	0.417	0.362	0.315	0.275	0.239	0.209	0.183	0.160	0.140	0.123
16	0.853	0.728	0.623	0.534	0.458	0.394	0.339	0.292	0.252	0.218	0.188	0.163	0.141	0.123	0.107
17	0.844	0.714	0.605	0.513	0.436	0.371	0.317	0.270	0.231	0.198	0.170	0.146	0.125	0.108	0.093
18	0.836	0.700	0.587	0.494	0.416	0.350	0.296	0.250	0.212	0.180	0.153	0.130	0.111	0.095	0.081
19	0.828	0.686	0.570	0.475	0.396	0.331	0.277	0.232	0.194	0.164	0.138	0.116	0.098	0.083	0.070
20	0.820	0.673	0.554	0.456	0.377	0.312	0.258	0.215	0.178	0.149	0.124	0.104	0.087	0.073	0.061

Number of Years	Interest Rate per Year														
	16%	**17%**	**18%**	**19%**	**20%**	**21%**	**22%**	**23%**	**24%**	**25%**	**26%**	**27%**	**28%**	**29%**	**30%**
1	0.862	0.855	0.847	0.840	0.833	0.826	0.820	0.813	0.806	0.800	0.794	0.787	0.781	0.775	0.769
2	0.743	0.731	0.718	0.706	0.694	0.683	0.672	0.661	0.650	0.640	0.630	0.620	0.610	0.601	0.592
3	0.641	0.624	0.609	0.593	0.579	0.564	0.551	0.537	0.524	0.512	0.500	0.488	0.477	0.466	0.455
4	0.552	0.534	0.516	0.499	0.482	0.467	0.451	0.437	0.423	0.410	0.397	0.384	0.373	0.361	0.350
5	0.476	0.456	0.437	0.419	0.402	0.386	0.370	0.355	0.341	0.328	0.315	0.303	0.291	0.280	0.269
6	0.410	0.390	0.370	0.352	0.335	0.319	0.303	0.289	0.275	0.262	0.250	0.238	0.227	0.217	0.207
7	0.354	0.333	0.314	0.296	0.279	0.263	0.249	0.235	0.222	0.210	0.198	0.188	0.178	0.168	0.159
8	0.305	0.285	0.266	0.249	0.233	0.218	0.204	0.191	0.179	0.168	0.157	0.148	0.139	0.130	0.123
9	0.263	0.243	0.225	0.209	0.194	0.180	0.167	0.155	0.144	0.134	0.125	0.116	0.108	0.101	0.094
10	0.227	0.208	0.191	0.176	0.162	0.149	0.137	0.126	0.116	0.107	0.099	0.092	0.085	0.078	0.073
11	0.195	0.178	0.162	0.148	0.135	0.123	0.112	0.103	0.094	0.086	0.079	0.072	0.066	0.061	0.056
12	0.168	0.152	0.137	0.124	0.112	0.102	0.092	0.083	0.076	0.069	0.062	0.057	0.052	0.047	0.043
13	0.145	0.130	0.116	0.104	0.093	0.084	0.075	0.068	0.061	0.055	0.050	0.045	0.040	0.037	0.033
14	0.125	0.111	0.099	0.088	0.078	0.069	0.062	0.055	0.049	0.044	0.039	0.035	0.032	0.028	0.025
15	0.108	0.095	0.084	0.074	0.065	0.057	0.051	0.045	0.040	0.035	0.031	0.028	0.025	0.022	0.020
16	0.093	0.081	0.071	0.062	0.054	0.047	0.042	0.036	0.032	0.028	0.025	0.022	0.019	0.017	0.015
17	0.080	0.069	0.060	0.052	0.045	0.039	0.034	0.030	0.026	0.023	0.020	0.017	0.015	0.013	0.012
18	0.069	0.059	0.051	0.044	0.038	0.032	0.028	0.024	0.021	0.018	0.016	0.014	0.012	0.010	0.009
19	0.060	0.051	0.043	0.037	0.031	0.027	0.023	0.020	0.017	0.014	0.012	0.011	0.009	0.008	0.007
20	0.051	0.043	0.037	0.031	0.026	0.022	0.019	0.016	0.014	0.012	0.010	0.008	0.007	0.006	0.005

Note: For example, if the interest rate is10%per year, the present value of PKR1 received at year 5 is PKR .621.

APPENDIX 2: Future Value Tables

Future value of PKR1 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 is10% per year, the investment of PKR1 today will be worth PKR 1.611 at year 5.

APPENDIX 3: Present Value Annuity Tables

Annuity table: Present value of PKR1 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	0.990	0.980	0.971	0.962	0.952	0.943	0.935	0.926	0.917	0.909	0.901	0.893	0.885	0.877	0.870
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	0.862	0.855	0.847	0.840	0.833	0.826	0.820	0.813	0.806	0.800	0.794	0.787	0.781	0.775	0.769
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 PKR1 received in each of the next 5 years is PKR 3.791.

APPENDIX 4: Future Value Annuity Tables

Values of e^{rt}. Future value of PKR1 invested at a *continuously compounded* rate *r* for *t* years.

rt.	0.00	0.01	0.02	0.03	0.04	0.05	0.06	0.07	0.08	0.09
0.00	1.000	1.010	1.020	1.030	1.041	1.051	1.062	1.073	1.083	1.094
0.10	1.105	1.116	1.127	1.139	1.150	1.162	1.174	1.185	1.197	1.209
0.20	1.221	1.234	1.246	1.259	1.271	1.284	1.297	1.310	1.323	1.336
0.30	1.350	1.363	1.377	1.391	1.405	1.419	1.433	1.448	1.462	1.477
0.40	1.492	1.507	1.522	1.537	1.553	1.568	1.584	1.600	1.616	1.632
0.50	1.649	1.665	1.682	1.699	1.716	1.733	1.751	1.768	1.786	1.804
0.60	1.822	1.840	1.859	1.878	1.896	1.916	1.935	1.954	1.974	1.994
0.70	2.014	2.034	2.054	2.075	2.096	2.117	2.138	2.160	2.181	2.203
0.80	2.226	2.248	2.271	2.293	2.316	2.340	2.363	2.387	2.411	2.435
0.90	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	10.070	10.180	10.280	10.380	10.490	10.590	10.700	10.800	10.910
2.40	11.020	11.130	11.250	11.360	11.470	11.590	11.700	11.820	11.940	12.060
2.50	12.180	12.300	12.430	12.550	12.680	12.810	12.940	13.070	13.200	13.330
2.60	13.460	13.600	13.740	13.870	14.010	14.150	14.300	14.440	14.590	14.730
2.70	14.880	15.030	15.180	15.330	15.490	15.640	15.800	15.960	16.120	16.280
2.80	16.440	16.610	16.780	16.950	17.120	17.290	17.460	17.640	17.810	17.990
2.90	18.170	18.360	18.540	18.730	18.920	19.110	19.300	19.490	19.690	19.890
3.00	20.090	20.290	20.490	20.700	20.910	21.120	21.330	21.540	21.760	21.980
3.10	22.200	22.420	22.650	22.870	23.100	23.340	23.570	23.810	24.050	24.290
3.20	24.530	24.780	25.030	25.280	25.530	25.790	26.050	26.310	26.580	26.840
3.30	27.110	27.390	27.660	27.940	28.220	28.500	28.790	29.080	29.370	29.670
3.40	29.960	30.270	30.570	30.880	31.190	31.500	31.820	32.140	32.460	32.790
3.50	33.120	33.450	33.780	34.120	34.470	34.810	35.160	35.520	35.870	36.230
3.60	36.600	36.970	37.340	37.710	38.090	38.470	38.860	39.250	39.650	40.040
3.70	40.450	40.850	41.260	41.680	42.100	42.520	42.950	43.380	43.820	44.260
3.80	44.700	45.150	45.600	46.060	46.530	46.990	47.470	47.940	48.420	48.910
3.90	49.400	49.900	50.400	50.910	51.420	51.940	52.460	52.980	53.520	54.050

Note: For example, if the continuously compounded interest rate is 10% per year, the investment of PKR 1 today will be worth PKR1.105 at year 1 and PKR1.221 at year 2.

APPENDIX 5: Present Value Annuity Tables

Present value of PKR1 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	0.995	0.990	0.985	0.981	0.976	0.971	0.967	0.962	0.958	0.954	0.950	0.945	0.941	0.937	0.933
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	10.140	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	0.929	0.925	0.922	0.918	0.914	0.910	0.907	0.903	0.900	0.896	0.893	0.889	0.886	0.883	0.880
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: For example, if the interest is 10% per year, a continuous cash flow of PKR 1 per year for 5 years is worth PKR 3.977. A continuous flow of PKR 1 in year 5 only is worth PRK 3.997 – PKR 3.326 = PKR 0.651

APPENDIX 6: Discount Factor Table

The following formula is used to calculate discount factor for year t and imputed rate of interest i: 1/(1+i)t

Number of Years	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

Book 2:
Energy Efficiency in Thermal Utilities

Guide Book

For

National Certification Examination

For Energy Auditors and Managers

National Energy Efficiency and Conservation Authority

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One of the main tasks of the project was the finalization of syllabus, and course modules including the development of model question banks for examination processes. This task was entrusted to a consortium of experts from two organizations, namely The Energy and Resources Institute (TERI) India, and PITCO from Pakistan.

This Book covers details of fuels and combustion processes, boilers, furnaces, steam systems, insulation and refractories, fluidized bed combustion, co-generation and waste heat recovery mechanisms.

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Their comments and feedback helped the consultants to make sure that the recommendations made were the most appropriate and fair in terms of benefits to the project developers, the government and other relevant partners.

Table of Contents

Chapter 1 Fuels and Combustion

1.1 Introduction to fuels

The various types 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/m^3.

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 oils is given in table 1.1.

Table 1.1: Specific gravity of various fuel oils

Fuel Oil	Light Diesel Oil (L.D.O.)	Furnace oil	Low Sulphur Heavy Stock (L.S.H.S.)
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 prescribed conditions. It is a very rough indication of the lowest temperature at which fuel oil is readily pump-able.

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, whereas 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 (GCV) or net calorific value (NCV). 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 in table 1.2.

Table 1.2: Typical Gross calorific value of some of the commonly used liquid fuels

Fuel Oil	Calorific Value (kCal/kg)
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.

$$GCV = NCV + (\frac{9H_2\% + M\%}{100}$$

Where,

GCV: Gross calorific value of fuel, kCal/kg
NCV: Net calorific value of fuel, kCal/kg
H2%: Hydrogen percentage by weight present in fuel
M%: Moisture percentage by weight present in 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 sulphur content of various fuel oils is given in Table 1.3.

Table 1.3: Typical sulphur content figures

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
L.S.H.S.	< 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 economizer.

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 of 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 equipment.

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 Table 1.4.

Table 1.4: Typical specification of fuel oil

Properties	Fuel Oils		
	Furnace Oil	**LS.H.S.**	**L.D.O.**
Density (Approx. g/cc at15°C)	0.89 - 0.95	0.88-0.98	0.85-0.87
Flash Point (°C)	66	93	66
Pour Point (°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 10 days 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 per year

Removal of Contaminants

Furnace oil arrives at the factory site either in tankers 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 Figure 1.1 gives an illustration of the duplex system of arrangement of strainers.

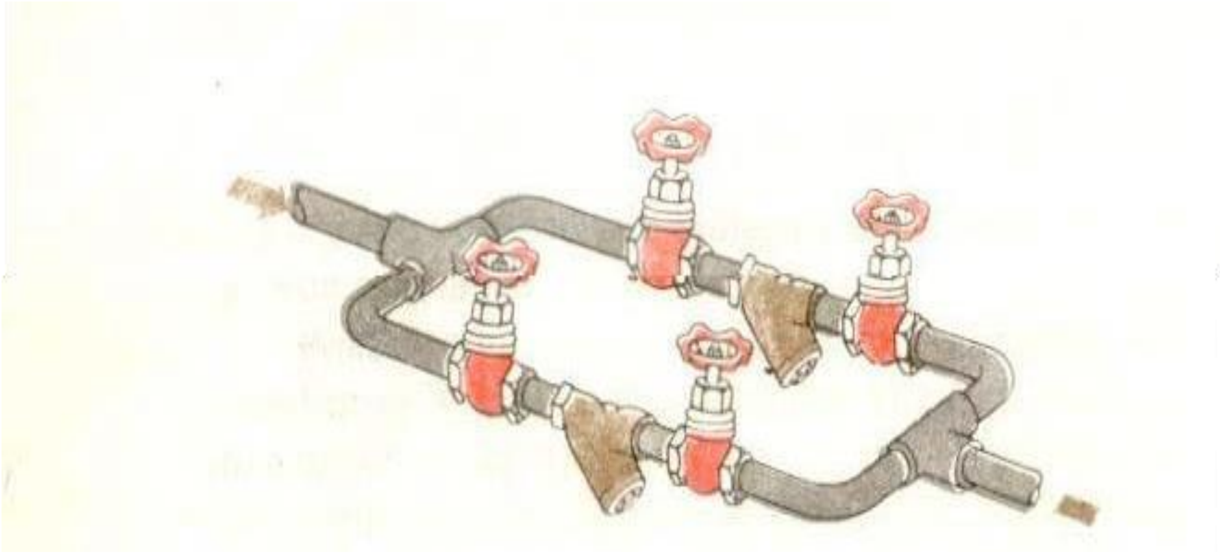


Figure 1.1: Duplex arrangement of strainers

Table 1.5 gives sizing of strainers at various locations.

Table 1.5: 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 rank and preheater	40	6
Between preheater 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 pumps have 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 pump-able. 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 Table 1.6.

Table 1.6: GCVs for various coals

Parameter	Lignite	Pakistan Coal	Indonesian Coal	South African Coal
GCV (kCal/kg)	6,300	2,900 – 8,616	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 types of coal is given in the Table 1.7.

Table 1.7: Typical proximate analysis of various types of coal

Parameter	Pakistan Coal	Indonesian Coal	South African Coal
Moisture, %	6.05	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

d) 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 to10%.
Moisture

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

e) 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 economizers
- 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 table 1.8.

Table 1.8: Ultimate analyses of Lignite and Indonesian coal

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

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 builds up in coal heap, on account oxidation may lead to spontaneous combustion of coal in storage.
The measures that would help in reducing the carpet loses are as follows:

- Preparing a hard ground for coal to be stacked upon.
- 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:

- Poor combustion conditions and inadequate furnace temperature.
- Higher excess air resulting in higher stack loss.
- Increase of unburnt in the ash.
- 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:

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

Table 1.9 gives the proper size of coal for various types of firing systems.

Table 1.9: Proper size of coal for various types of firing systems

S.No	Firing	Size, mm
1	(a) Natural draft	25-75
	(b) Forced draft	25-40
2	Stoker Firing	
	(a) Chain grate	
	i) Natural draft	25-40
	ii) Forced draft	15-25
	(b) Spreader Stoker	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 coal is very high, wetting of coal can decrease the percentage of unburnt carbon and excess air level required to be supplied for combustion. Table 1.10 shows the extent of wetting, depending on the percentage of fines in coal.

Table 1.10: 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 1.11 and 1.12.

Table 1.11: Proximate analysis of various types of coal

Parameter	Leco fines	Lignite	Pakistan Coal	Thar Coal (variety of Pakistan Coal)	Indonesian Coal	South African Coal
Moisture (%)	9.92	49.79	4 – 9	29.9	9.43	8.5
Ash (%)	5.93	10.41	35 – 50	4.9	13.99	18
Volatile matter	24.08	47.76	16 - 42	35.4	29.79	23.28
Fixed Carbon (%)	60.70	41.83	11 - 44	29.8	46.79	51.22

Table 1.12: Ultimate analysis of various coals

Parameter	Leco fines	Lignite	Pakistan Coal	Thar Coal (variety of Pakistan Coal)	Indonesian Coal
Carbon (%)	71.02	62.01	60 - 78	69.9	58.96
Hydrogen (%) + Nitrogen(%) + Oxygen(%)	12.58	26.99	17.7 - 38	28.2	17.06
Sulphur (%)	0.55	0.59	3 – 4.9	1.9	0.56
GCV(kCal/kg)	7242	6301	2900 - 8616	6858	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/Nm^3) 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 in Table 1.13.

Table 1.13: 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 Temperature, °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 (C_3H_8), Propylene (C_3H_6), 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 time as heavy as air. Consequently, the vapour may flow along the ground and into drains sinking to the lowest level of surroundings and be ignited at a considerable distance from the source of leakage. In still air, vapour will disperse slowly. Escape of even small quantities of 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 and 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 accounts 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 1.14.

Table 1.14: Comparison of carbon contents in oil, coal and gas

Parameters	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 table 1.15.

Table 1.15: Typical Properties of Agro Residues

Parameters	Deboiled Bran	Paddy Husk	Saw Dust	Coconut Shell
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 (O_2) 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 reducing diluting agent 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 (NOx), 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 kilogram of fuel than when CO or smoke are produced.

$$C + O_2 \rightarrow CO_2 + 8084\ \text{kCal/kg of Carbon}$$
$$2C + O_2 \rightarrow 2CO + 2430\ \text{kCal/kg of Carbon}$$
$$2H_2 + O_2 \rightarrow 2H_2O + 28{,}922\ \text{kCal/kg of Hydrogen}$$
$$S + O_2 \rightarrow SO_2 + 2{,}224\ \text{kCal/kg of Sulphur}$$

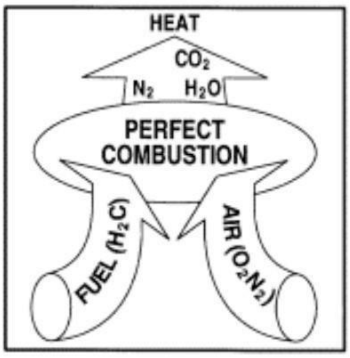
3 T's of Combustion

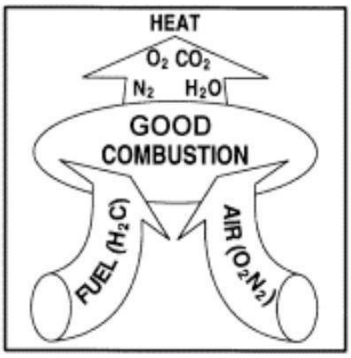
The objective of good combustion is to release all of the heat in the fuel. This is accomplished by controlling the "three T's" of combustion which are (1) Temperature high enough to ignite and maintain ignition of the fuel, (2) Turbulence or intimate mixing of the fuel and oxygen, and (3) Time sufficient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

Not all of the energy in the fuel is 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 CO_2.





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-1which would require heating the oil to about 105^{0}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 stoichiometric 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 is proper and combustion is perfect. The combustion products are primarily Carbon Dioxide (CO_2), water vapor (H_2O) and Sulphur Dioxide (SO_2), which pass through the chimney along with the Nitrogen (N_2) in the air.

Rules for combustion of oil

- Atomize 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 flue gases leave the system through the chimney, carrying away 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_2O	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_2O	18

$$C + O_2 = CO_2$$

$$H_2 + {}^1\!/_2\, O_2 = H_2O$$

$$S + O_2 = SO_2$$

Element wise calculation

$$C + O_2 = CO_2$$

$$12 + 32 = 44$$

12 kg of carbon requires 32 kg of oxygen to form 44kg of carbon dioxide.

Thus 1kg of carbon would require (32/12=) 2.67kg of oxygen to form 3.67kg of carbon dioxide. So, 85.9kg of carbon would require (85.9x2.67) = 229.3kg of oxygen to produce 314.97kg of carbon dioxide

$$2H_2 + O_2 = 2H_2O$$

$$4 + 32 = 36$$

4 kg of hydrogen requires 32 kg of oxygen to form 36kg of water.

Thus 1kg of hydrogen would require (32/4=) 8kg of oxygen to form 9kg of water.

$$12H_2 + (12 \times 8)O_2 = (12 \times 9)H_2O$$

So, 12kg of hydrogen would require (12x8) = 96kg of oxygen to produce 108kg of water.

$$S + O_2 = SO_2$$

$$32 + 32 = 64$$

32 kg of sulphur requires 32 kg of oxygen to form 64kg of sulphur dioxide.

Thus 1kg of sulphur would require (32/32=) 1kg of oxygen to form 2kg of sulphur dioxide

$$0.5\mathrm{S} + (0.5 \times 1)\mathrm{O}_2 = (0.5 \times 2)\mathrm{SO}_2$$

So, 0.5kg of sulphur would require (0.5x1) = 0.5kg of oxygen to produce 1kg of sulphur dioxide.

$$Total\ theoritical\ oxygen\ reguired = (229.3 + 96 + 0.5)kg$$

$$= 325.8\ kg$$

$$Oxygen\ already\ present\ in\ 100kg\ of\ fuel = 0.7kg$$

$$Additional\ oxygen\ required = (325.8 - 0.7)kg = 325.1kg$$

$$Quantity\ of\ dry\ air\ required = \frac{325.1}{0.23} = 1413.48kg\ of\ air$$

(Since air contains 23% oxygen by weight)

Theoretical air required for 100kg of fuel = 1413.48kg

Theoretical air required for 1 kg of fuel = 14.13kg

Nitrogen in flue gas = 1413.48-325.1+0.5 = 1088.88kg

Theoretical CO_2% if dry flue gas is calculated as below:

$$Moles\ of\ CO_2 in\ flue\ gas = \frac{314.97}{44} = 7.16$$

$$Moles\ of\ N_2\ in\ flue\ gas = \frac{1088.88}{28} = 38.88$$

$$Moles\ of\ SO_2\ in\ flue\ gas = \frac{1}{64} = 0.016$$

$$Theoretical\ CO_2\%\ by\ volume = \frac{Moles\ of\ CO_2}{Total\ moles\ of\ dry\ flue\ gas} \times 100$$

$$Theoretical\ CO_2\%\ by\ volume = \frac{7.16}{7.16 + 38.88 + 0.016} \times 100 = 15.5\%$$

Calculation of constituents of flue gas by excess air

$$\%\ CO_2\ measured\ in\ flue\ gas = 10\%\ (measured\ value)$$

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

= 52.4%

Theoretical air required for 100kg of fuel burnt = 1413.48kg

At 52.4% excess air, total quantity of air supplied = (1413.48x1.524)kg = 2154.14kg

Excess air quantity = (2154.14 – 1413.48)kg = 740.66kg

Oxygen = (740.66*0.23)kg = 170.35kg

Nitrogen = (740.66-170.35)kg = 570.31kg

The final constituents of flue gas with 52.4% excess air for every 100kg of fuel is

CO_2 = 314.97kg; H_2O = 108kg; SO_2 = 1kg; O_2 = 170.23kg

N_2 = (1088.88 + 570.31)kg = 1659.19kg

Determination of actual CO_2% by calculating in dry flue gas by volume
Moles of CO_2 in flue gas = 314.97/44 =7.16
Moles of SO_2 in flue gas = 1/64 = 0.016

Moles of O_2 in flue gas = 170.23/32 = 5.32

Moles of N_2 in flue gas = 1659.19/28 = 59.26

$$Actual\ CO_2\%\ by\ volume = \frac{Moles\ of\ CO_2}{Total\ moles\ (dry)} \times 100$$

$$= \frac{7.16}{7.16 + 0.016 + 5.32 + 59.26} \times 100$$

$$= \frac{7.16}{71.756} \times 100 = 10\%$$

$$Actual\ O_2\%\ by\ volume = \frac{5.32 \times 100}{71.756} = 7.42\%$$

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 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 (CO_2) or oxygen (O_2) in flue gases by continuous recording instruments or Orsat apparatus or some other portable instruments, the excess air level as well as stack losses can be estimated with the graph as shown in Figure 2 and Figure 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.

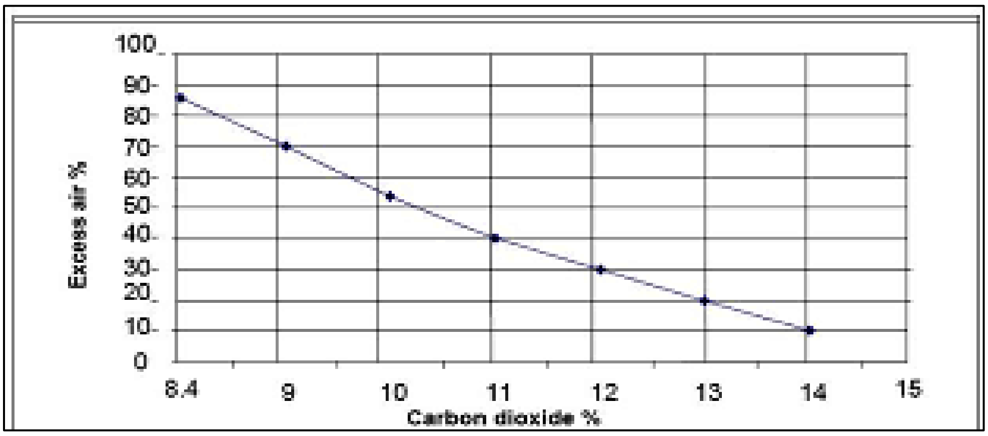


Figure 1.2: Relation between CO2 and excess air for fuel oil

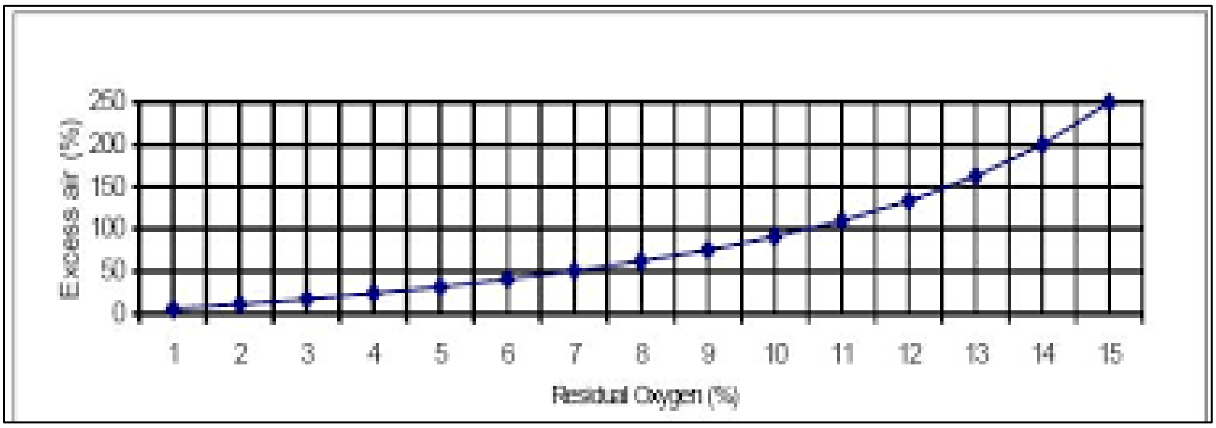


Figure 1.3: Relation between residual oxygen and excess air Oil Firing

Burners

The burner is the principal device for firing of the fuel. The primary function of burner is to atomize 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 atomized, more readily will the particles come in contact with the oxygen in 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.

Figure 1.4 shows an 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.

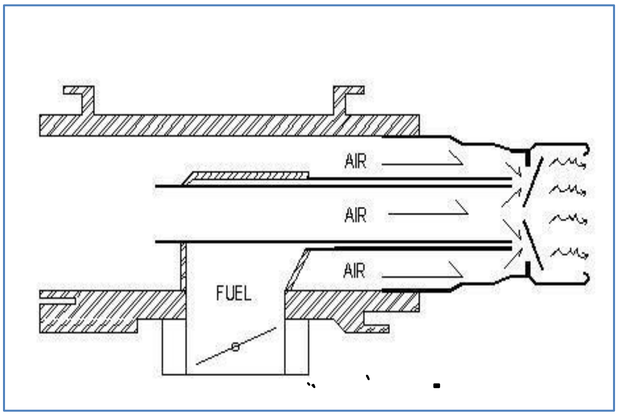


Figure 1.4: Amplified burner head

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 250,000 kCals and minimum rate is 50,000 kCals, 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

1 kg 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 un burnt (black smoke) and forming carbon monoxide instead of carbon dioxides.

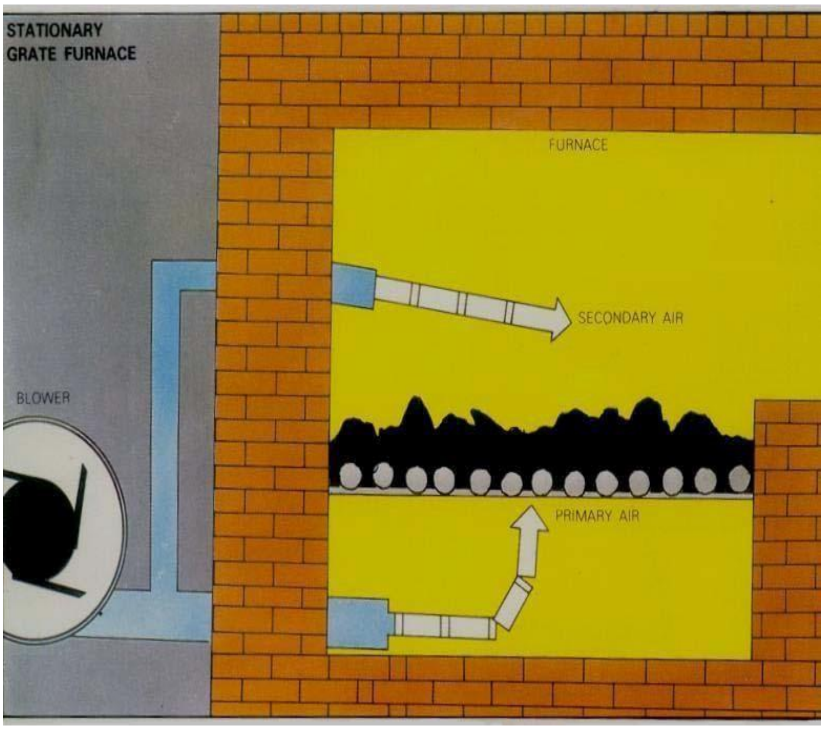


Figure 1.5: Stoker fired boilers

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 1.5** 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 varies from 9.5:1 to 10:1.

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

$$CH_4 + O_2 = CO_2 + 2H_2O$$

For every 16kg of methane that is consumed, 12kg of carbon is released and 44kg of carbon dioxide is 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.

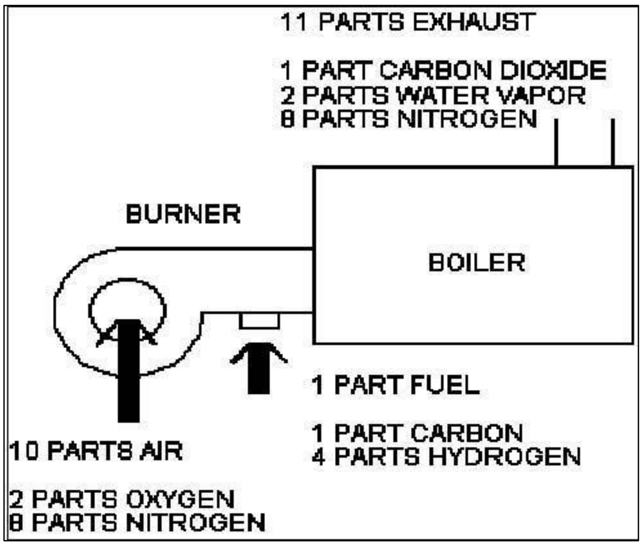


Figure 1.6: Combustion of natural gas

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 (2psi), 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 assembly is encased in a rectangular cast-iron box, built in to the boiler setting and having louver doors in 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 a venturi 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 venturi can be increased or decreased by turning a revolving Shutter, which can be locked in any desired position. Excess air level in natural gas burner is in the order of 5%.

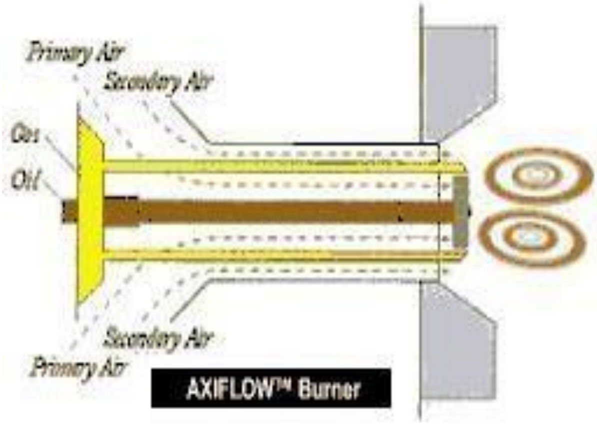


Figure 1.8: High pressure burner

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 air, flows 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 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 a slight negative pressure below the atmospheric pressure so that combustion air flows through the system.

Forced Draft: The Forced draft system uses a fan for delivering air to 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 also 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 CO_2 in the flue gas while 15% excess air is supplied.

Solution:

$$CH_4 + 2O_2 = CO_2 + 2H_2O$$

1 mole of ethane requires 2 moles of oxygen

16kg of methane requires, 64kg of oxygen

16 kg of methane produces 44kg of carbon dioxide

Therefore, 500kg/h of methane would require 2000kg/h of oxygen and produce 1375kg/h of carbon dioxide.

Theoretical air required for combustion = 2000/0.23 kg/h = 8695.6kg/h

Considering 15% excess air,

Actual air supplied for combustion = 8695.6x1.15kg/h = 10,000kg/h

Flue gas generated at 15% excess air = (10000 + 500)kg/h = 10500kg/h

Percentage of CO2 in flue gas = 1375/10500*100% = 13.09%

Problem -2:

Propane is used as fuel in heaters for preheating paints. Calculate the Air to Fuel ratio for complete combustion of C_3H_8 (Propane) and CO_2 released per kg of propane, if 15% excess air is supplied to the heater.

Solution:

$$C_3H_8 + 5O_2 = 3CO_2 + 4H_2O$$

1 mole of propane requires 5 moles of oxygen

Molecular weight of propane is 44kg per mole

44kg of propane requires, 160kg of oxygen

Theoretical air required for combustion = 160/0.23 kg/h = 695.6kg/h

For 15% excess air,

Actual air supplied for combustion = 695.6x1.15kg/h = 800kg/h

Air to fuel ratio = 800/44 = 18.18

From above reaction,

44kg of propane produces 132kg of carbon dioxide

Thus 1kg of propane will produce 3kg of CO_2

Chapter 2 Boiler

2.1 Introduction

A boiler is an enclosed vessel that provides a mechanism for combustion heat to be transferred into water until it becomes heated water or steam. The steam or hot water under pressure is then usable for transferring 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°C)
Type of boiler	3 Pass Fire tube Package Boiler
Design steam pressure	10.5 kg/cm2 (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 Figure 2.1.

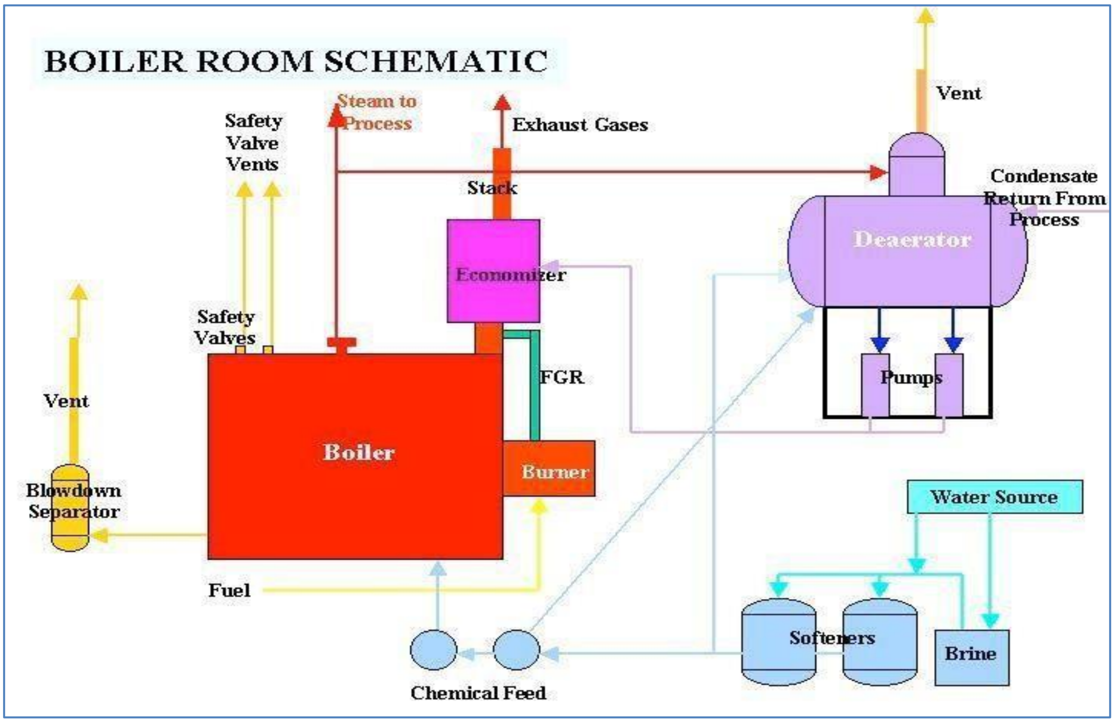


Figure 2 .1: Boiler room

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 using heat in flue gas.

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 gases 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/h and pressure of 17.5 kg/cm^2.

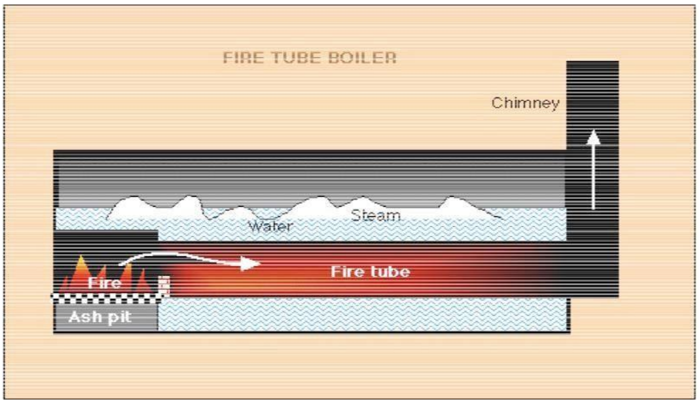


Figure 2.2: Fire tube boiler

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

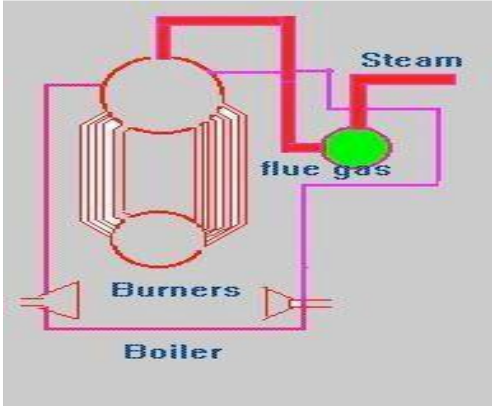


Figure 2.3: Water tube boiler

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 design so 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.
- Large 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.

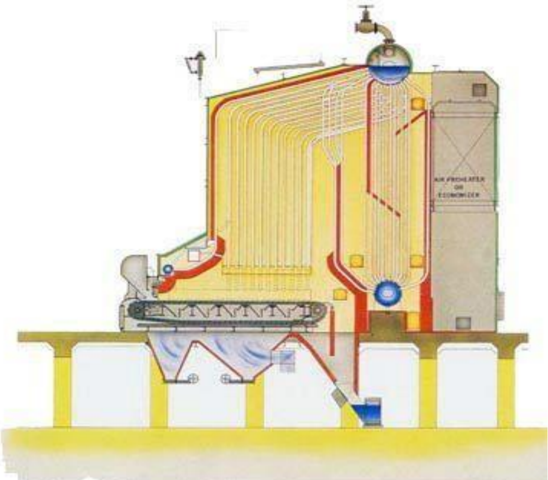


Figure 2.5: Chain grate boiler

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 Figure 2.5).

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 meter (µm) and 70-75% is below 75 microns, for 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.

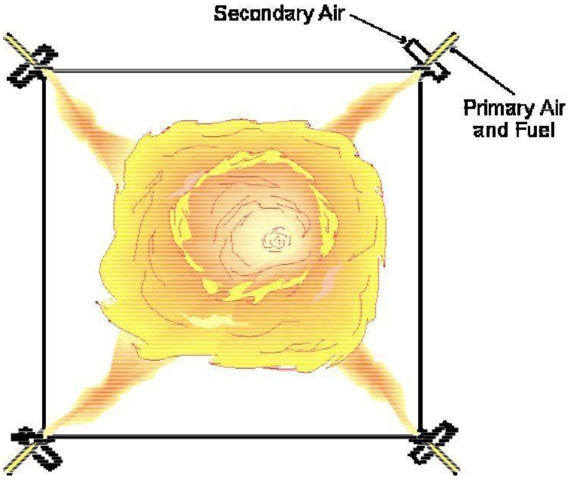


Figure 2.6: Tangential firing

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.

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)

FBC Boiler

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

When 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.

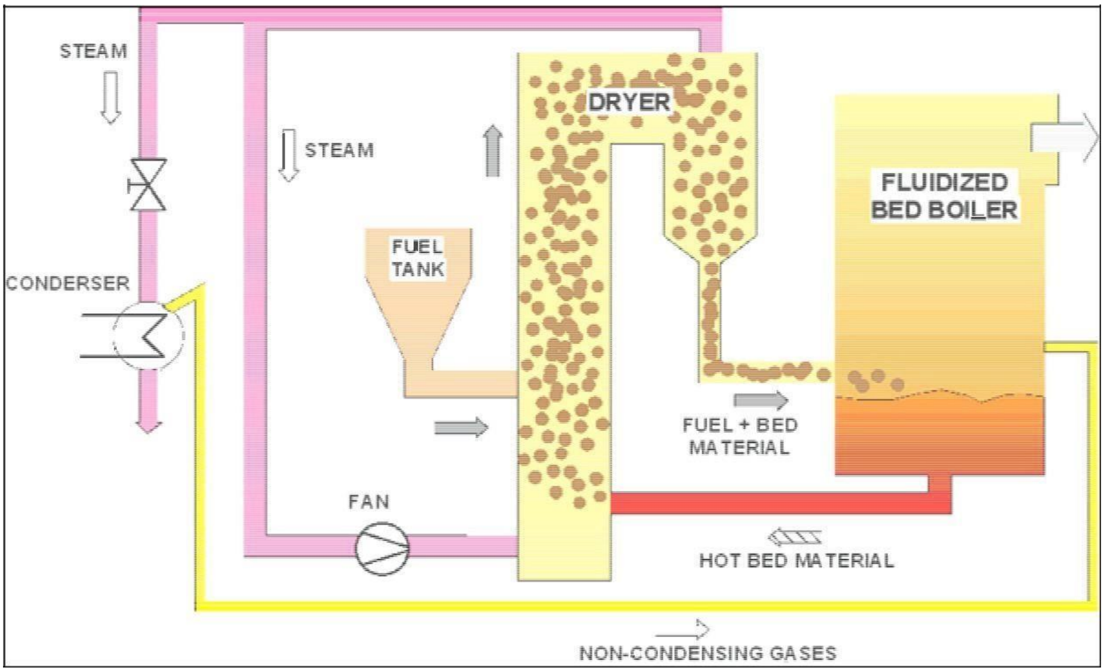


Figure 2.7: Schematic of fluidized bed boiler

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 - economizer, evaporator and super heater the supercritical boiler has only an economizer 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 minimize 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.

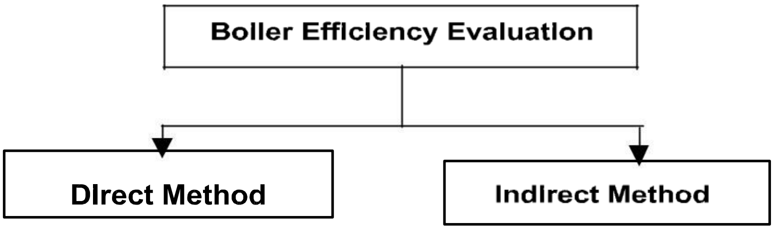
2.4 Performance Evaluation of Boilers

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 lead to poor boiler performance. Efficiency tests helps to identify 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.

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



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.

$$Boiler\ Efficieny = \frac{Heat\ output}{Heat\ input} \times 100$$

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/cm^2(g)) and superheat temperature (^{O}C), if any
- The temperature of feed water (^{O}C)
- Type of fuel and gross calorific value of the fuel (GCV) in kCal/kg of fuel

$$Boiler\ efficiency, \eta = \frac{Q \times \left(h_g - h_f\right)}{q \times GCV} \times 100$$

Where,

hg - Enthalpy of saturated steam in kCal/kg of steam

hf - 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 :

$$Boiler\ efficiency = \frac{8 \times (665 - 85)}{1.8 \times 3200} \times 100$$

$$Boiler\ efficiency = 80.5\%\ (on\ GCV\ basis)$$

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 insignificant.

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

Indirect Method

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

Indirect method is also called as heat loss method. The efficiency can be arrived at, by subtracting the heat loss fractions from 100. All standards do not include 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 (H_2, O_2, S, C, moisture content, ash content)
- Percentage of Oxygen or CO_2 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)

Steps for calculating boiler efficiency by indirect method:

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

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

$$Actual\ mass\ of\ air\ supplied\ per\ kg\ of\ fuel(AAS) = \left\{1 + \frac{EA}{100}\right\} \times Theoretical\ air$$

i. Percentage Heat loss due to dry flue gas

$$= \frac{m \times C_p \times (T_f - T_{a)}}{GCV of\ fuel} \times 100$$

Where,

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

= (mass od dry products of combustion per kg of fuel)+(mass of N_2 per kg of fuel)+(mass of N_2 in actual mass of air supplied)

C_p = specific heat of flue gas (0.24 kCal/kg°C)

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

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

Where,

H2 = Percentage of hydrogen in 1kg of fuel

0.45 = Specific heat of superheated steam

584 = Latent heat of superheated vapour at partial pressure

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

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

Where,

M = Percentage of moisture in 1kg of fuel

iv. Percentage heat loss due to moisture in air

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

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

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

Where,

%CO = Volume of CO in flue gas

(1% = 10000 ppm)

$\%CO_2$ = Actual volume of CO_2 in flue gas

C = Carbon content, kg/kg of fuel

vi. Percentage heat loss due to unburnt in flyash

$$= \frac{Total\ flyash\ collected\ per\ kg\ of\ fuel\ burnt \times GCV\ of\ flyash}{GCV\ of\ fuel} \times 100$$

vii. Percentage heat loss due to unburnt in bottom ash

$$= \frac{Total\ bottom\ ash\ collected\ per\ kg\ of\ fuel\ burnt \times GCV\ of\ bottom\ ash}{GCV\ of\ fuel} \times 100$$

viii. Percentage of heat loss due to radiation and other unaccounted losses

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% to1% are typical. The loss may be assumed appropriately depending on the surface condition.

$$Boiler\ efficiency, \eta = 100 - (i + ii + iii + iv + v + vi + vii + viii)$$

Example: Calculating boiler efficiency by indirect method

- Type of boiler : Oil fired
- Ultimate analysis of Oil : C - 84.0%; H_2 -12.0%; S- 3.0%; O_2 -1.0%
- GCV of Oil : 10200kCal/kg
- Percentage of Oxygen in flue gas : 7
- Percentage of CO_2 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 x100)/(21-7) =50%

2. Theoretical air requirement

   = [(11.6 x C) + {34.5 x (H_2 – O_2/8)} + (4.35 x S)]/100 kg/kg of fuel

   = [(11.6 x 84) + {34.5 x (12 – 1/8)} + (4.35 x 3)]/100 kg/kg of fuel

   = 974.4 + 409.6875+13.05

   = 13.97

3. Actual mass of air supplied per kg of fuel (AAS)

   =[1+EA/100]x Theo .Air

   = [1 + 50/100] x13.97

   = 20.96

4. Percentage heat loss due to dry flue gas (L1)
5.

$$= \frac{m \times C_p \times (T_f - T_a)}{GCV of\ fuel} \times 100$$

m = (0.84 x (44/12)) + (0.03 x (64/32)) + (20.96 x 0.77) + ((20.96 – 13.97) x 0.23)
= 3.08 + 0.06 + 16.14 + 1.61

= 20.89

L1 = 20.89 x 0.24 x (220 – 27) x 100 / 10200 = 9.49%

6. Percentage heat loss due to evaporation of water formed due to H2 in fuel (L2)

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

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

7. Percentage heat loss due to moisture in air

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

L3 = 20.96 x 0.018 x 0.45 (220-27) x 100 / 10200 = 0.31%

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

Boiler efficiency, η = 100 – (L1+L2+L3+L4)
= 100 – (9.49 + 7.1 + 0.31 + 3.5) = 79.6%

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 solids and 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

Sl. No.	Boiler Type	Maximum TDS (ppm)
1.	Lancashire	10,000 ppm
2.	Smoke and water tube boilers (12 kg/cm2)	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:

$$Boiler\ blowdown\ \% = \frac{Feed\ water\ TDS\ \times \%\ of\ Make\ up\ water}{(Maximum\ permissible\ TDS\ in\ boiler\ water - Feed\ water\ TDS)}$$

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:

= [(300 x 10) / (3000 – 300)]

= 1.11%

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

= 3000 x 0.0111

= 33.3kg/hr

Conductivity as Indicator of Boiler Water Quality

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

Intermittent vs. Continuous Blow down

Conventional methods for blowing down of the boiler are - 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 boiler 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.

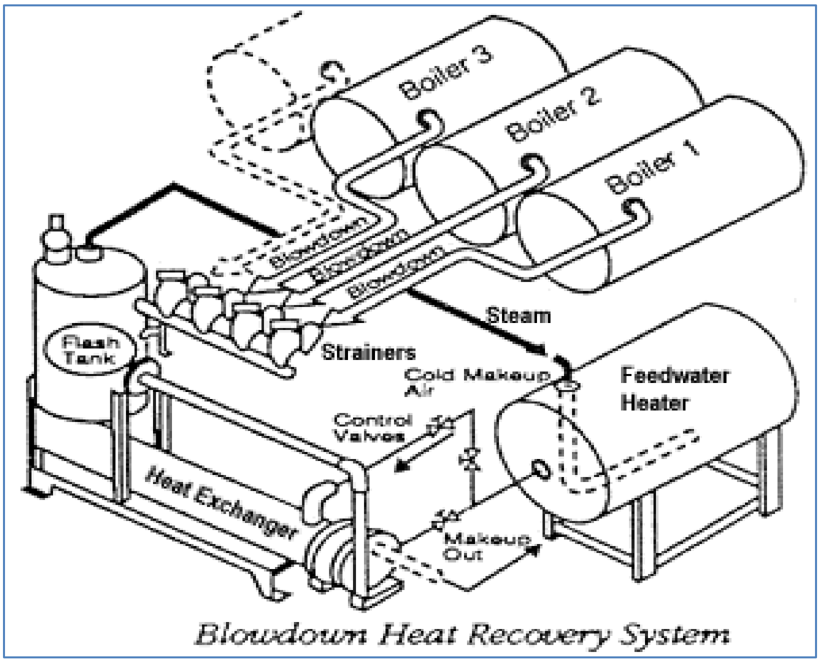


Figure 2.8: Blow down heat recovery system

Benefits of Blow down

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

- Lower pretreatment costs
- Less make-up water consumption
- Reduced maintenance down 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 sludges, which can be removed by blow down. This method is limited to boilers, where feed water is low in hardness salts, so 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 types of water 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.

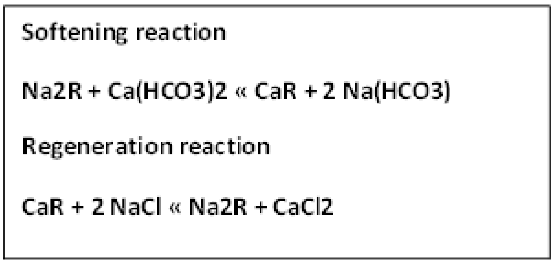
Methods of pre-treatment include simple sedimentation in settling tanks or settling in clarifiers with aid of coagulants and flocculants. Pressure sand filters, with spray aeration to remove carbon dioxide and iron, may be used to remove metal salts from bore well water.

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

Na2R + Ca(HCO3)2 « CaR + 2 Na(HCO3)

Regeneration reaction

CaR + 2 NaCl « Na2R + CaCl2

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).

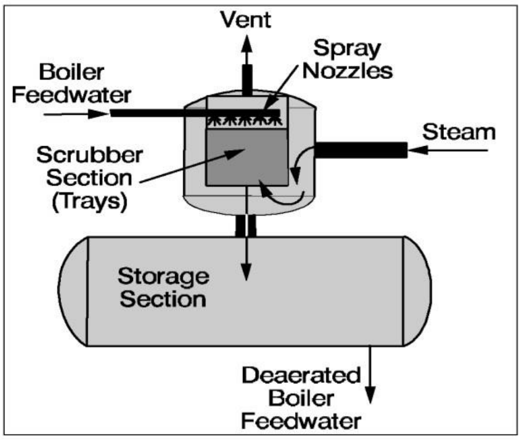


Figure 2.9: Deaerator

Removal of oxygen, carbon dioxide and other 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 and 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 105oC. 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.

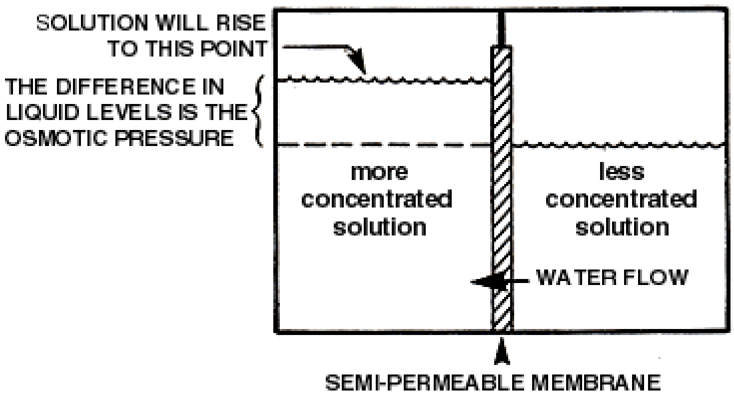
Chemical de-aeration

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; this 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.

Figure 1 - 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 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.

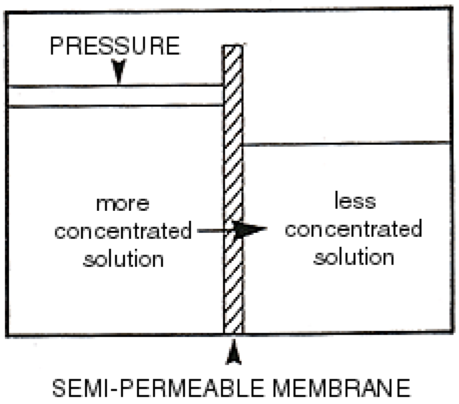
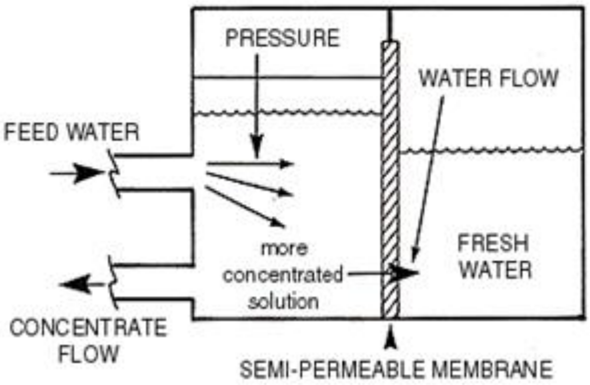
	When a pressure is applied to the concentrated solution which is great than the osmotic pressure difference, the direction of water passage through the membrane *is reversed* and the process that we refer to as reverse osmosis is established. That is, the membrane's ability to selectively pass water is unchanged, only the direction of the water flow is changed.
	The feed water and *concentrate (reject stream) ports* 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 untreated feed water quality, treatment process used and boiler operating procedures. As a general rule, higher the boiler's operating pressure, 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/cm2	21 - 40Kg/cm2	41 - 60Kg/cm2
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 residual, ppm	-	-	-0.02-0.04
pH at 25°C	8.8-9.2	8.8-9.2	8.2-9.2
Hardness	1.0	0.5	-

Table 2.3: Typical Recommended boiler water limits

Factor	Up to 20Kg/cm2	21 - 40Kg/cm2	41 - 60Kg/cm2
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 Economizer

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 Preheat

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 color of 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 and 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

Table 2.4 gives the theoretical amount of combustion air required for 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	m^3 of flue/kg of fuel	Theoretical CO2% in dry flue gas	CO2% 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 analyzers 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 are more 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% of the gross calorific value at full rating, but will increase to around 6%, if the boiler operates at only 25% 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 up on tubes acts as an insulator against 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 review 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 rises by 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 affected 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 evaluated.

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 mass flow rate of the flue gases through tubes. This reduction in flow rate for the same heat transfer area reduces 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 boiler can be financially attractive if the existing boiler is:

- old and in efficient
- 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 Economizer

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

Boiler capacity (TPH)	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 analyzer and data logger. The result is summarized below:

Thermal efficiency : 80.99%
Flue gas Temperature : 315°C
CO_2 : 13%
CO : 167PPM

The temperature of 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 : 5.04TPH
Average flue gas temperature : 315°C
Average steam generation / kg of fuel oil : 16.05kg
Feed water inlet temperature : 110°C
Fuel oil supply rate : 314kg/h
Flue gas quantity : 17.4 kg/kg of fuel

Cost Economics

Parameter	Value
Quantity of flue gases	= 5463.6kg/h
Quantity of heat available in the flue gases	= 5463.6 x0.25 x(315-200)
	= 157078kCal/h
Rise in the feed water temperature	= 26°C
Heat required for pre-heating the feed water	= 5040 x 1.065 x 26
	= 139557kCal/h
Saving in terms of HSD fuel (considering GCV of HSD as 10000 kCal/kg)	= 139557 kCal/h /10000 kCal/kg
	= 14kg/h
Annual operating hours	= 8600
Annual savings of fuel oil	= 120400kg

Conclusion

Through recovery of waste heat by installation of an economizer, the paper mill was able to save 14kg/h of HSD fuel, which amounts to about 120,400 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:

$$NCV = GCV - \left[9 \times \frac{\%\, of H_2 in\ fuel}{100} + \frac{\%\ of\ moisture\ in\ fuel}{100}\right] \times 584$$

$$NCV = 10500 - \left[9 \times \frac{12}{100} + \frac{1}{100}\right] \times 584$$

$= \quad 10500 - [9 \times 0.12 + 0.01] \times 584$

$= \quad 10500 - 636.56$

$= \quad 9863$ kCal /kg

$$Boiler\ efficiency\ on\ NCV\ basis = \frac{85}{9863} \times 100$$

$= \quad 90.5\%$

Problem -2:

A textile plant is using furnace oil as fuel for firing in the boiler, generating steam on an average of 30TPH. The unit has decided to switch over to natural gas as fuel owing 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 hours	: 8000
Efficiency of natural gas boiler	: 86%

Calculate the Reduction in GHG emissions?

Solution:

Furnace oil fired boiler:

Kg of CO_2/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 = $21.95*10^6/10200 = 2.152$TPH.
CO_2 emission with furnace oil = 2.152* 3.08 = 6.628TPH.

Gas fired Boiler:

Kg of CO_2/kg of gas = 0.74* (44/12) = 2.71

Heat input to boiler = 18/0.86 = 20.93 million kCal/h

Natural gas consumption = $20.93* 10^6/9500 = 2203$ Sm^3/h
= 2203*0.8/1000 = 1.7624TPH

CO_2 emission with natural gas = 1.7624*2.71 = 4.776TPH

Annual CO_2emission reduction = (6.628-4.776)*8000 = 14816 T/y

Problem -3:

Oil fired Boiler is generating 100 TPH of steam at 85% efficiency, operating 330 days in a year. Management installed a water treatment plant at PKR 30.6 Million of investment cost for reducing the TDS in boiler feed water from 450ppm to 150ppm. 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 1200kCal/kg. Calculate the payback period if the cost of fuel is PKR 53,750 / Ton.

Solution:

$$Boiler\ blowdown\ \% = \frac{Feed\ water\ TDS\ \times \%\ of\ Make\ up\ water}{(Maximum\ permissible\ TDS\ in\ boiler\ water - Feed\ water\ TDS)}$$

Initial blow down	= 450 * 10 / (3000 – 450)	= 1.76 %
Improved blow down	= 150 * 10 / (3000 – 150)	= 0.53 %
Reduction in blow down	= 1.76 – 0.53	= 1.24 %
Reduction in blow down	= 1.24 * 100 * 1000 / 100	= 1238 kg/h

Specific heat of water is 1 kCal/kg °C

Heat savings = $m * Cp * (T_1 – T_2)$ = 1238 * 1 * (175 – 45)

= 160991 kCal/h

Fuel oil saving = 160991 / (1200 * 0.85) = 157.83 kg/hr
Annual fuel oil savings = 157.83 * 24 * 330 / 1000
= 1250 MT / annum
Fuel oil cost savings = 1250 * 53750 = PKR 67.18 million
Investment on water treatment plant = PKR 30.6 million
Payback period = 30.6 / 67.18
Payback period = 0.45 years (or) 5 months

Chapter 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^{0}C i.e. containing heat value of 25kCal is heated by adding 75kCal, the water is brought to boiling point of 100^{0}C.*

Enthalpy of Evaporation (Heat Content of Steam)

Enthalpy of evaporation is the heat energy to be added to 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 it 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****. If a boiler is operating at a pressure of 8kg/cm*^{2}*, steam saturation temperature is170° C and steam enthalpy or total heat of dry saturated steam is given by:*

hf +hfg= 171.35 +489.46 = 660.81 kCal/kg.

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

171.35+ 0.96 x 489.46 = 641.23 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 100^0C. 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 $h_g = h_f + x.h_{fg}$ where x 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.

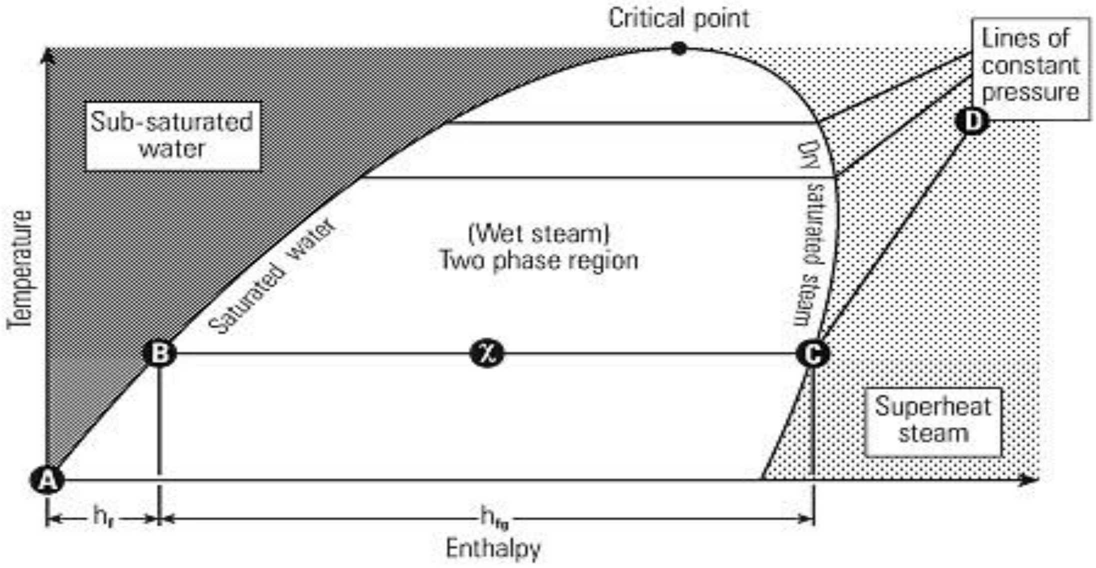


Figure 3.1: Steam Phase Diagram

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, hf, (**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, hfg, (**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.

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/cm2)	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	143.7	509.96	653.66	0.47
5	151	152.13	503.9	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

Thermal Energy Basics

Temperature

Temperature is a physical property that quantitatively expresses the common notions of hot and cold. Objects of low temperature are cold, while various degrees of higher temperatures are referred to as warm or hot. Temperature is measured with thermometers, which may be calibrated to a variety of temperature scales. Much of the world uses the Celsius scale for most temperature measurements. In Fahrenheit scale (British system), the freezing point of water is 32°F and the boiling point of water is 212°F at atmospheric pressure.

The Kelvin scale is the temperature standard for scientific or engineering purposes. It has the same incremental scaling(1°) as the Celsius scale, but fixes its origin, or null point, at absolute zero (0K = −273.15°C)

Conversion of the degree Celsius into Fahrenheit = (°C x 1.8) + 32

Conversion of the Fahrenheit into degree Celsius = (°F - 32) / 1.8

Degrees Celsius (C) to degrees Kelvin (K) = °C + 273 = (K)

Pressure

It is the force per unit area applied to outside of a body.

$P = F/A = ma/A = mg/A$ (when $g=a$)

P is the pressure in N/m^2 or Pascals

F is the force in Newtons (N)

a is the acceleration in m/s^2

g is the acceleration due to gravity in m/s^2

Absolute pressure

The absolute pressure (ps) is total or true pressure. It is measured relative to the absolute zero pressure - the pressure that would occur at absolute vacuum. All calculation involving the gas laws requires pressure to be in absolute units and temperature in Kelvin.

Gauge Pressure

Gauge pressure (pg) is the pressure indicated by a gauge. All gauges are calibrated to read zero at atmospheric pressure. Gauges indicated the pressure difference between a system and the surrounding atmosphere. The gauge pressure can be expressed as
pg = ps - pa

where
pg = gauge pressure
ps = system pressure (absolute)
pa = atmospheric pressure

Atmospheric Pressure

Atmospheric pressure (pa) is pressure in the surrounding air at the surface of the earth. The atmospheric pressure varies with temperature and altitude above sea level.

Standard Atmospheric Pressure

Standard Atmospheric Pressure (atm) is used as a reference for gas densities and volumes. The Standard Atmospheric Pressure is defined at sea-level at 273oK (0^oC) and is 1.01325 bar or 101325 Pascal (absolute). The temperature of 293^oK (20^oC) is also used.

1 atm = 1.01325 bar = 101.3 kPa= 760 mmHg =10.33 meter H2O = 1013 mbar = 1.0332 kgf/cm^2

Heat

Heat is transferred from one body to another body at a lower temperature by virtue of temperature difference i.e. Heat is energy in transition or transitory energy. The quantity of heat depends on the quantity and type of substance involved. Calorie is the unit for measuring the quantity of heat. It is the quantity of heat, which can raise the temperature of 1g of water by 1°C. Calorie is too small a unit for many purposes. Therefore, a bigger unit kilocalorie (1 kilocalorie = 1000 calories) is used to measure heat. 1 kilocalorie can raise the temperature of 1000g (i.e. 1kg) of water by 1°C. However, nowadays generally Joule as the unit of heat energy is used. It is the internationally accepted unit. Its relationship with calorie is as follows:

1 Calorie = 4.187 J $\approx$ 4.2 J

Specific Heat

If the same amount of heat energy is supplied to equal quantities of water and milk, their temperature goes up by different amounts. This is due to different specific heats of different substances. Specific heat is defined as the quantity of heat required to raise the temperature of 1kg of a substance through 1°C or 1 K. Specific heat is expressed in terms of kcal/kg^{o}C or J/kg K. Specific heat varies with temperature. In case of gases-there are an infinite number of processes in which heat may be added to raise gas temperature by a fixed amount and hence a gas could have an infinite numbers of specific heat capacities. However-only two specific heats are defined for gases i.e. specific heat at constant pressure, cp and specific heat at constant volume, Cv. For solids and liquids, however, the specific heat does not depend on the process.

The specific heat of water is very high as compared to other common substances; it takes a lot of heat to raise the temperature of water. Also, when water is cooled, it gives out a large quantity of heat.

Sensible Heat

The amount of heat which when added to any substance causes a change in temperature. The changes in temperature that do not alter the moisture content of air. It is expressed in calories or Joules.

Sensible heat = mass x specific heat x change in temperature
Q = m Cp DT

Phase Change

The change of state from the solid state to a liquid state is called fusion. The fixed temperature at which a solid changes into a liquid is called its melting point. The change of a state from a liquid state to a gaseous is called vaporization. The fixed temperature at which a liquid changes into a vapour is called its boiling point. The change of a state from gaseous state to a liquid state is called condensation.

Latent heat

It is the change in heat content of a substance, when its physical state is changed without a change in temperature.

Latent heat of fusion

The latent heat of fusion of a substance is the quantity of heat required to convert 1 kg solid into liquid state without change of temperature. It is represented by the symbol hif. Its unit is Joule per kilogram (J/Kg) Thus, QL (ice) = 335 KJ/kg. The change in phase occurs in either direction at the fusion temperature i.e. liquid to solid and solid to liquid. The temperature and quantity of heat to bring about the change will be the same in either case and can be determined from the following equation:

QL = m x hif
Where QL = The quantity of latent heat in kilojoules
m = The mass in kg
hif = The latent heat of fusion in kJ/kg

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 network, 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.

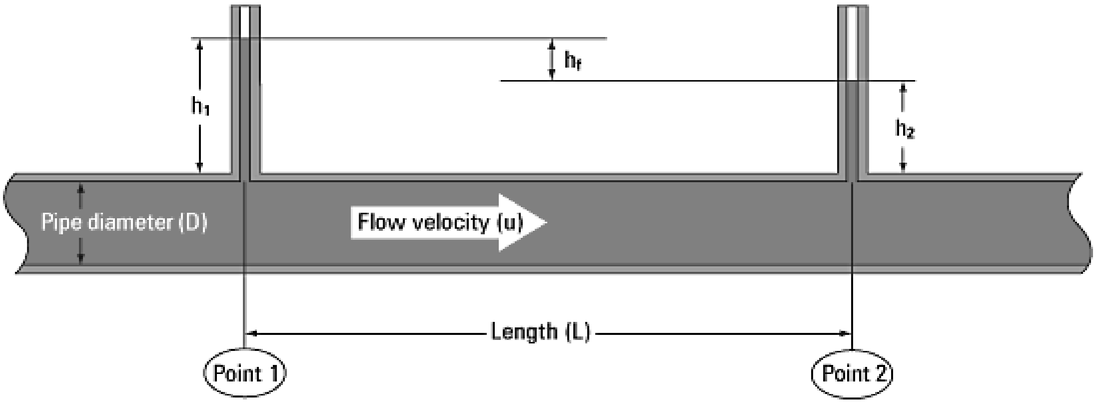


Figure 3.2: Pressure drop in steam pipes

This is illustrated by the equation,

$$h_f = \frac{4fLu^2}{2gD}$$

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/s^2)
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 flow rate is 45 m^3/h at 15°C and the friction factor for this pipe is taken as 0.005.

Solution:

$$Velocity\ (m/s) = \frac{Volume\ (m^3/s)}{Cross\ setional\ area\ (m^2)}$$

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

Velocity = 0.71m/s

$$h_f = \frac{4fLu^2}{2gD}$$

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

h_f = 3.43m ~ 0.343bar

Example-2: Determining the pipe size

A process requires 5000 kg/h of dry saturated steam at 7 kg/cm^2 (g). For the flow velocity not to exceed 25 m/s, determine the pipe size

Solution:

Flow rate : 5000 kg/h or 1.398 kg/s
Specific volume at 7kg/cm^2 : 0.24 m^3/kg
Flow velocity : 25m/s
Volume flow rate = 1.398x0.24 m^3/s
= 0.333m^3/s

Thus

$$D^2 = \frac{4 \times Volume\ flow\ rate}{\pi \times Velocity}$$

$$D = \sqrt{\frac{4 \times 0.33}{\pi \times 25}} = 0.13m$$

Since the steam velocity must not exceed 25m/s, the pipe size must be at least 130mm; the nearest commercially available size, 150mm, 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 meters length in the direction of the steam flow
2. Drain points should be provided at intervals of 30-45 meters 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, de-superheating is often required, to compensate for superheat gained in PRV application due to isenthalpic expansion. Pressure reduction and de-superheating 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 steam after de-superheating will be closer to saturation temperature for heat transfer applications.

The de-super heating of steam is done by spraying water through a spray nozzle into a pipe. Normally, the de-super 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 heating 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 a heat source: [1000 – 6000]W/m^2K
- The rate at which heat is transferred to the heat transfer surface of a heat exchanger using steam as a heat source: [6000 – 15000]W/m^2K

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 kCal/kg°C). The latent heat of steam at 1 kg/cm^2 is 525kCal/kg.

Solution:

Quantity of water evaporated from milk = 680x0.25kg
= 170kg/batch
Heat required for raising temperature of milk from 26 to 100°C = 690x0.9x(100-26)
= 45288 kCal/batch
Amount of heat required to evaporate 170kg of water = 170x540
= 91800 kCal/batch
Total heat required = (45288+91800) kCal/batch
= 137088 kCal/batch
Quantity of steam required = 137088/525
= 261kg per batch

Thermo-compressor

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 thermos- 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 thermos-compressing would give a large improvement in waste heat recovery.

Thermo-compressors 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 thermo-compressor. As the nozzle opens, the high velocity motive steam draws the lower- pressure steam into the thermo-compressor 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 thermo-compressor. 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 thermos-compressor. A typical application is in evaporators where the boiling steam is recompressed and used as heating steam.

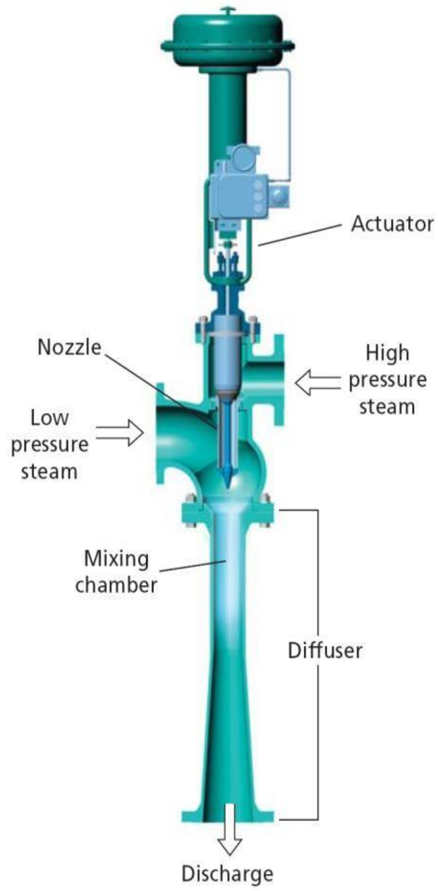


Figure 3.3: Thermo-compressor

Advantages of thermo-compressors

- No condensation losses takes place
- Thermal efficiency of the system is extremely high
- Entrainment of low pressure steam results is 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 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.

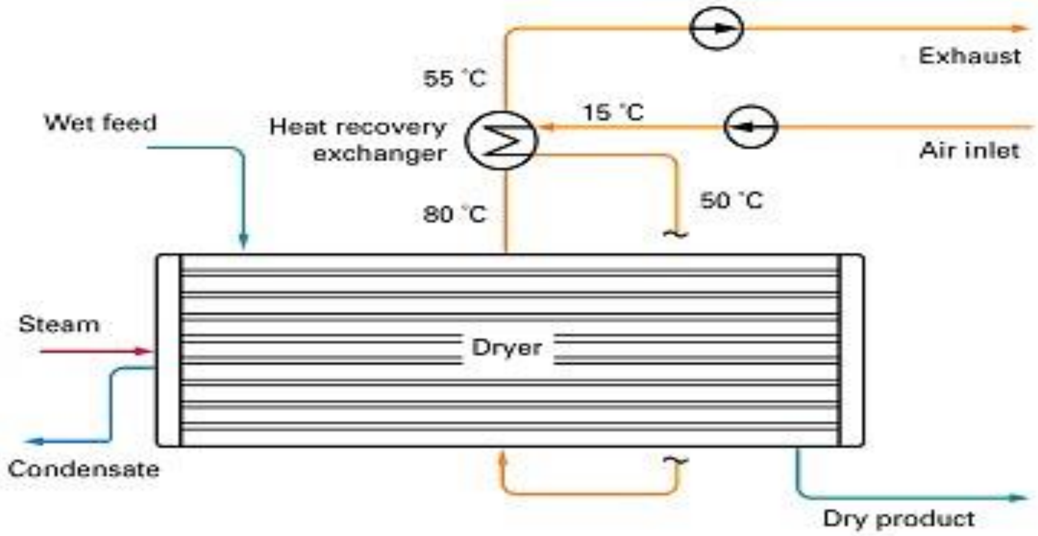


Figure 3.4: Hot air dryer using steam

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

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.

Solution:

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 x 200)/900 g = 22.2 g moisture are associated with 200 g dry matter.

1 kg of original matter must lose (800 - 22) g moisture = 778 g = 0.778 kg moisture.
Heat energy required for 1 kg original material = heat energy to raise temperature to 100°C + latent heat to remove water

= (100 - 21) x 3.8 + 0.778 x 2257

= 300.2 + 1755.9

= 2056 kJ.

Energy/kg water removed, as 2056 kJ are required to remove 0.778 kg of water,

= 2056/0.778

= 2643 kJ.

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).

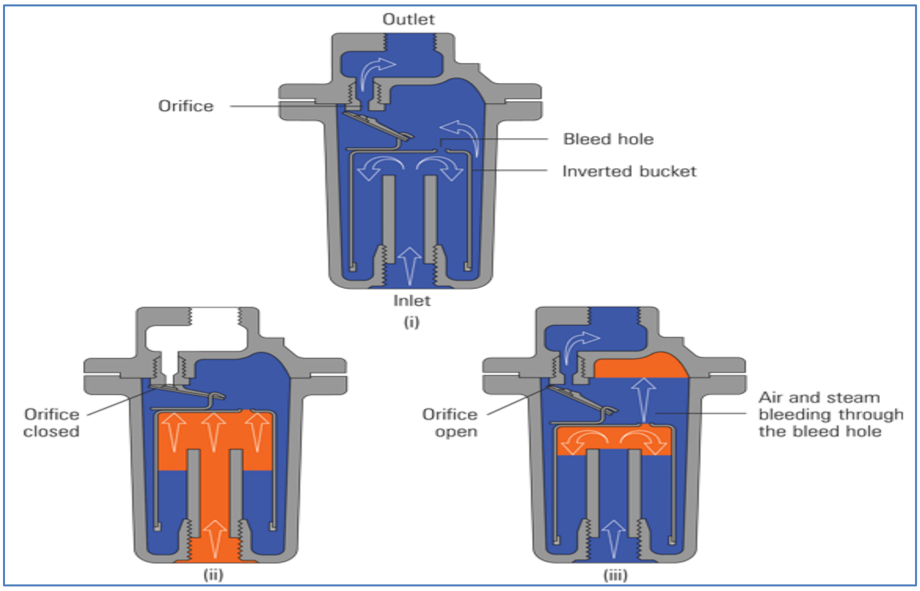


Figure 3.5: Inverted bucket trap

Inverted bucket traps, as a group, are capable of handling a wide range of steam pressures and condensate capacities. However, each specific steam trap handles 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.

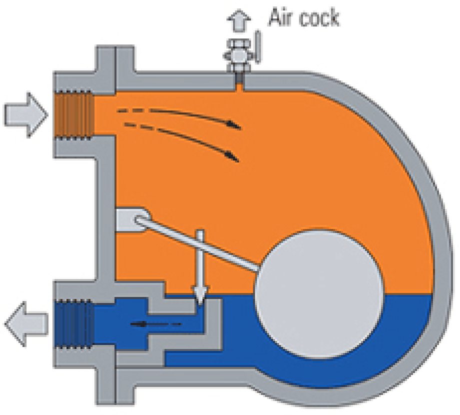


Figure 3.6A: Float trap with air cock

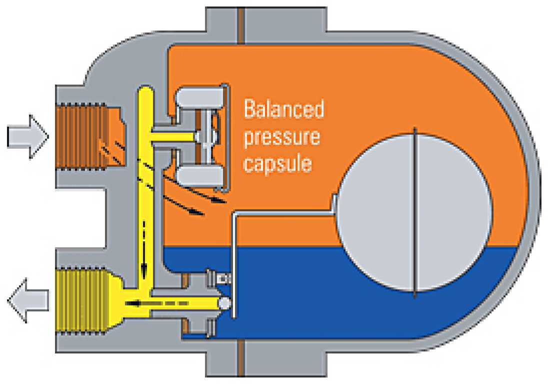


Figure 3.6B: Float trap with thermostatic air vent

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).

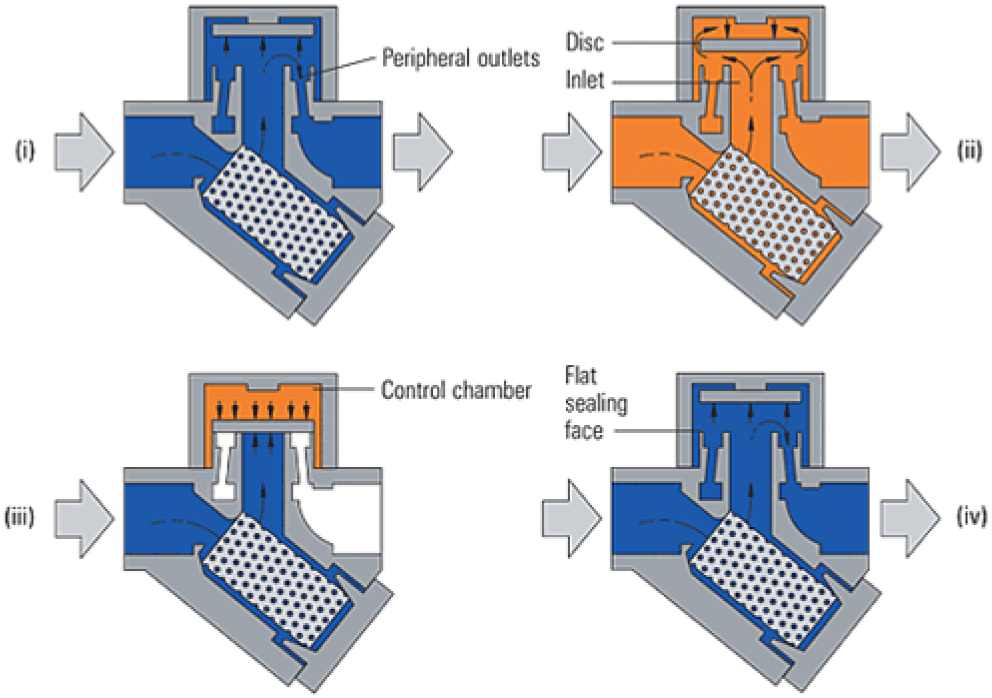


Figure 3.7: Thermodynamic Trap

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).

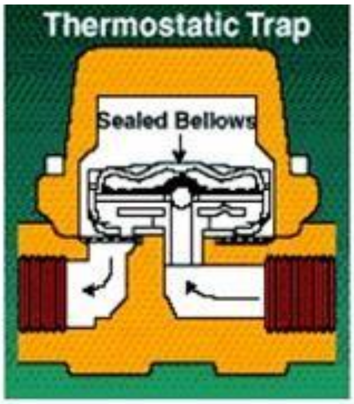


Figure 3.8: Thermostatic trap

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).

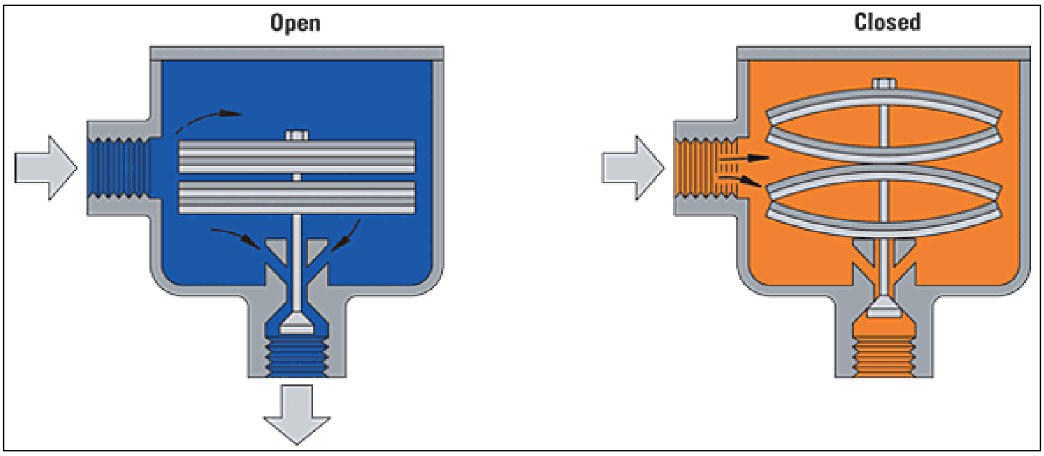


Figure 3.9: Bimetallic Trap

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 off at least 100mm diameter is needed in such cases.

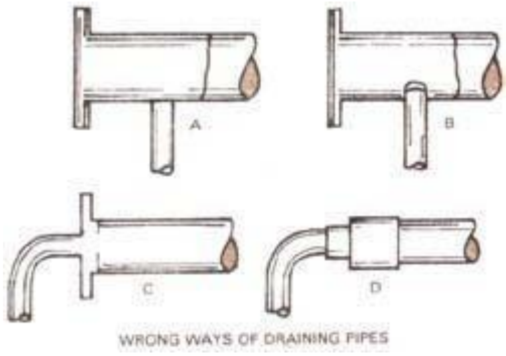


Figure 3.10A: Wrong ways of draining pipe

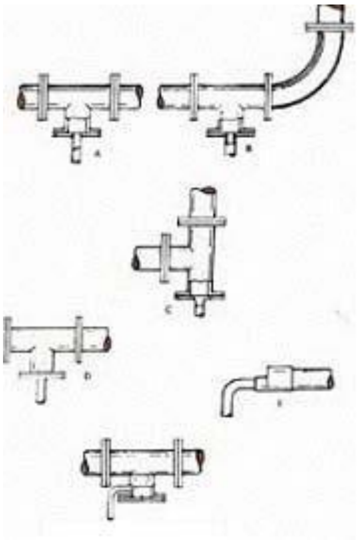


Figure 3.10B: Right ways of raining pipe

Figures 3.10 A and 3.10 B shows 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.

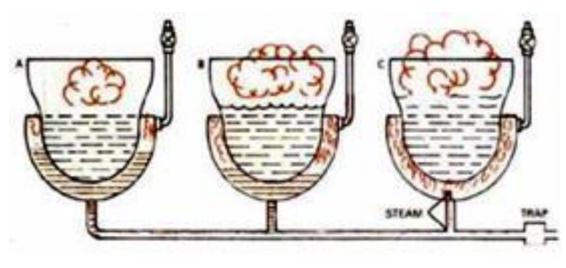
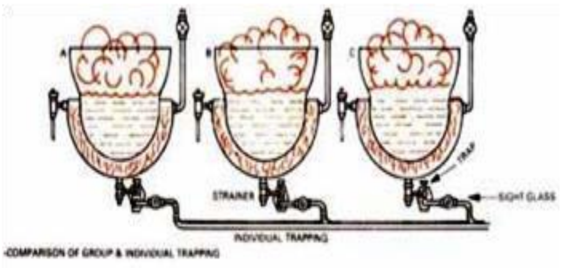
	

Figure 3.11 A Group Trapping	Figure 3.11 B Individual Trapping

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. 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.

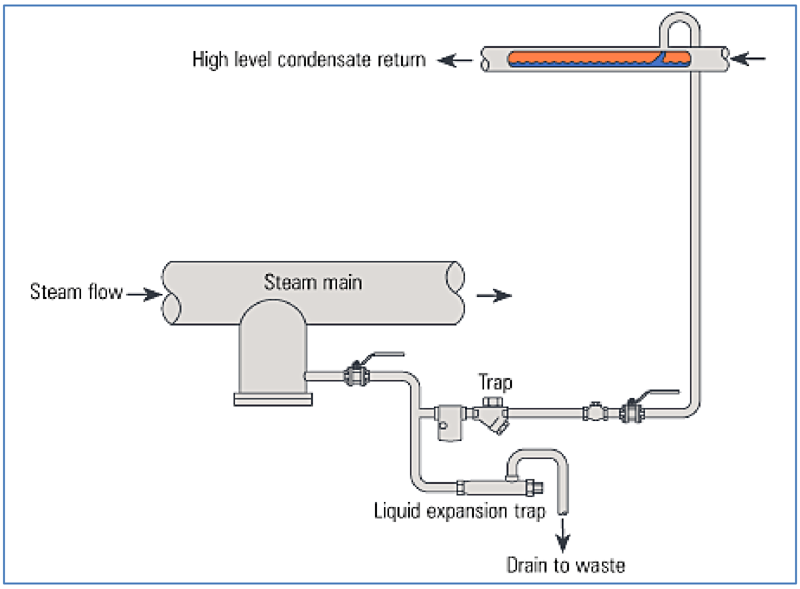


Figure 3.12 Use of a Liquid Expansion Trap

The discharge line from the trap to overhead return line preferably discharges into the top of 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 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.

A sight glass fitted just after a steam trap is also very useful from daily plant operation view point. 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	o Open to atmosphere, small capacity o Frequent change in pressure o Low pressure - high pressure	Thermodynamic type
Equipment o Reboiler o Heater o Dryer o Heat exchanger, etc.	o Large capacity o Variation in pressure and temperature is undesirable o Efficiency of the equipment is a problem	Mechanical trap, Bucket, Inverted bucket, float
o Tracer line o Instrumentation	o Reliability with no overheating	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.

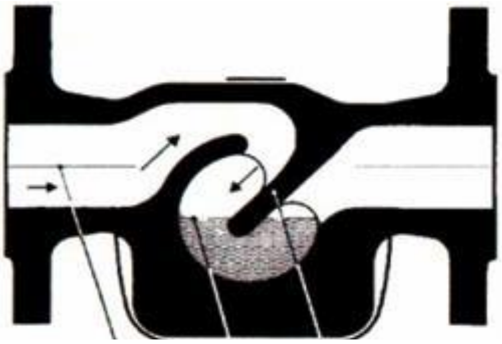


Figure 3.13: Sight Glass

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.

Figure 3.15: Infrared gun

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.

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/cm^2 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.

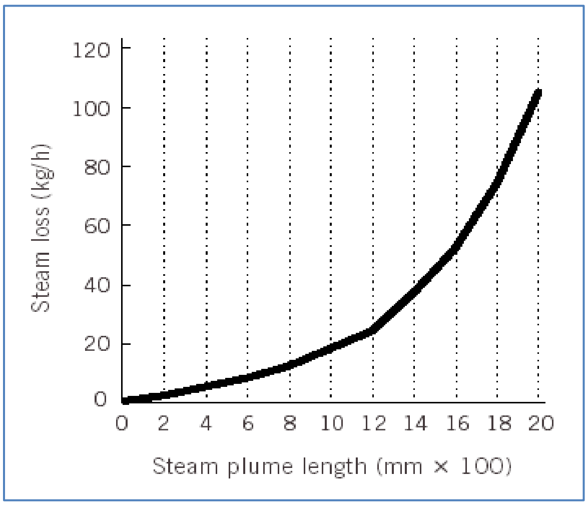


Figure 3.16: Steam leaks vs. plumes

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

Sl. 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 between 95-98%.

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 steam. 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.

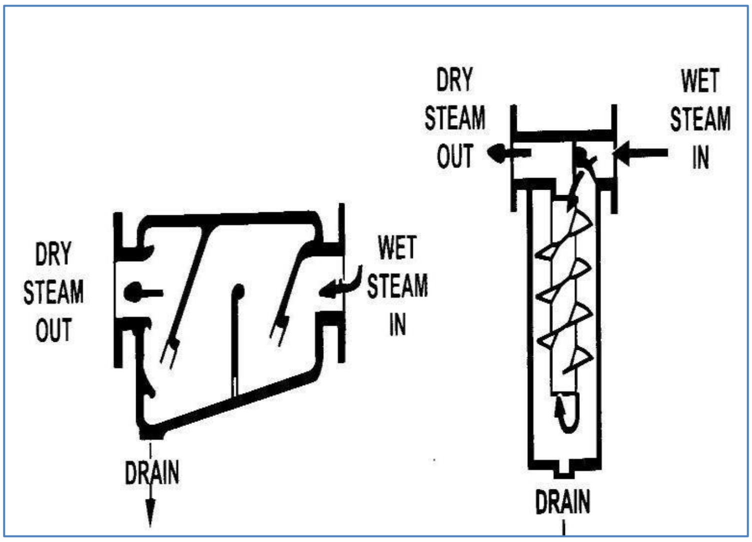


Figure 3.17: Steam Separators

5. Utilizing 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.

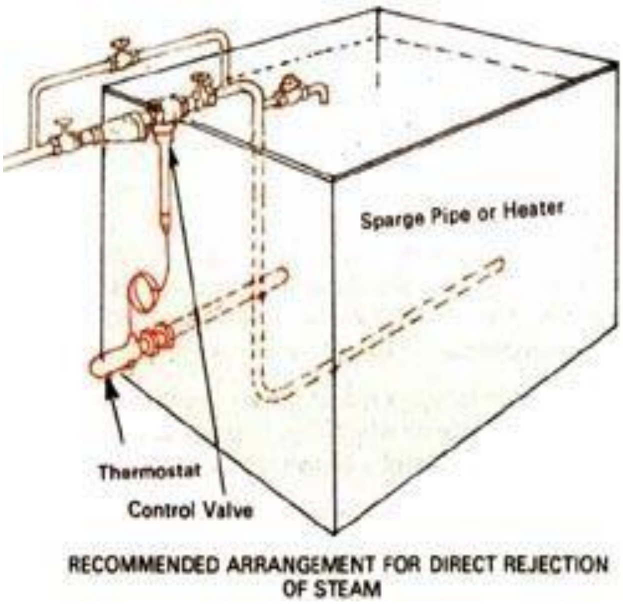


Figure 3.18: Temperature Control for Directly Injected Steam

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. Minimizing 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.

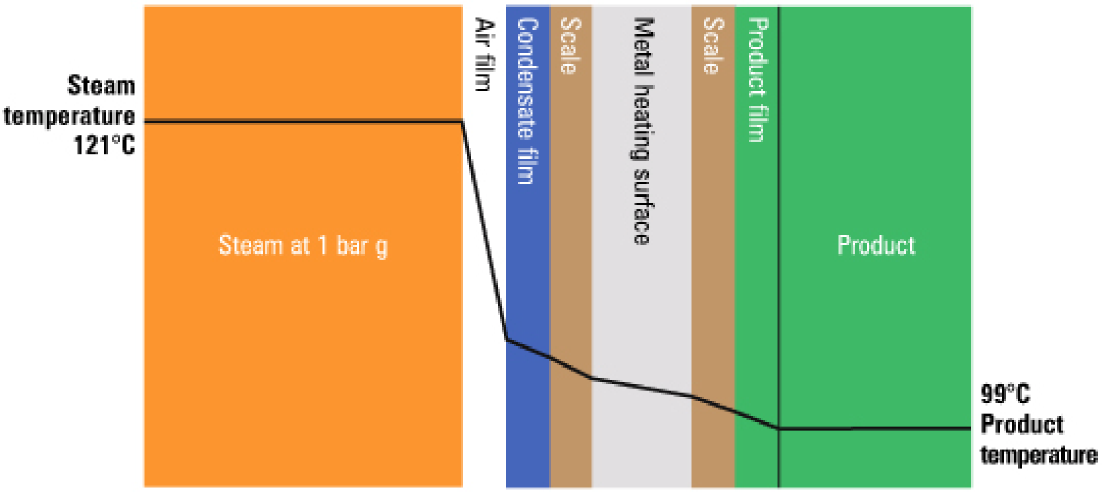


Figure 3.19: Heat Transfer Barriers

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 times 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 minimize 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

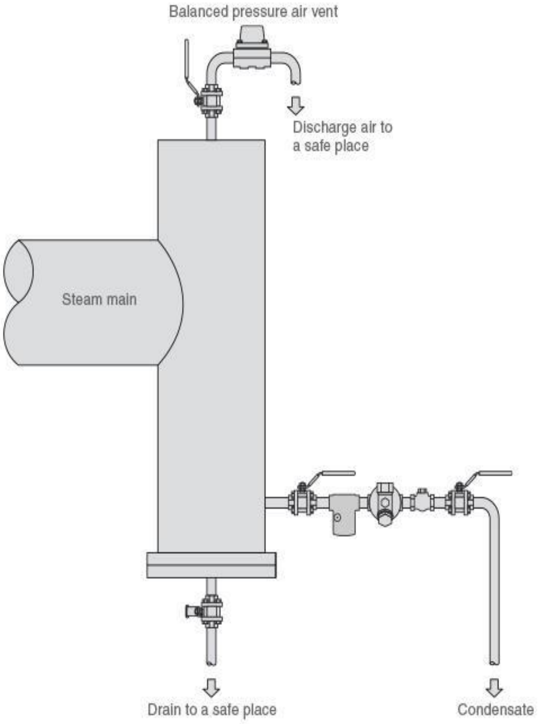


Figure 3.20: Air Vent

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 6^0C 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.

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.

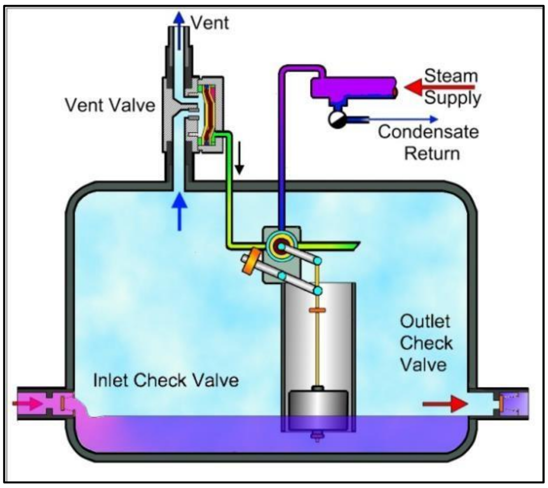


Figure 3.21: Pressure Powered Pump

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	Un-insulated
½	15	125	692
2	25	243	1820
4	40	298	2942
12	50	588	7614

*** Comparison of Radiation Losses (Pipe Surface Temperature at 150 ºC)**

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 uninsulated. 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	PKR Per Year	2900	14

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:

$$Flash\ steam\ percentage, \% = \frac{S_1 - S_2}{L_2}$$

Where,

S1: sensible heat of higher pressure condensate.

S2: sensible heat of the steam at lower pressure (at which it has been flashed).

L2: 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.

Therefore, in this example, the percentage of flash steam evaporated

$$= \frac{302}{2258} \times 100\%$$

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.

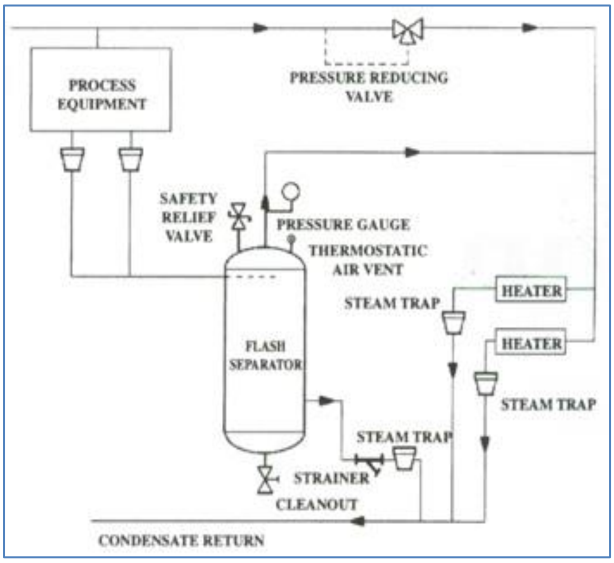


Figure 3.22: Flash steam recovery

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.

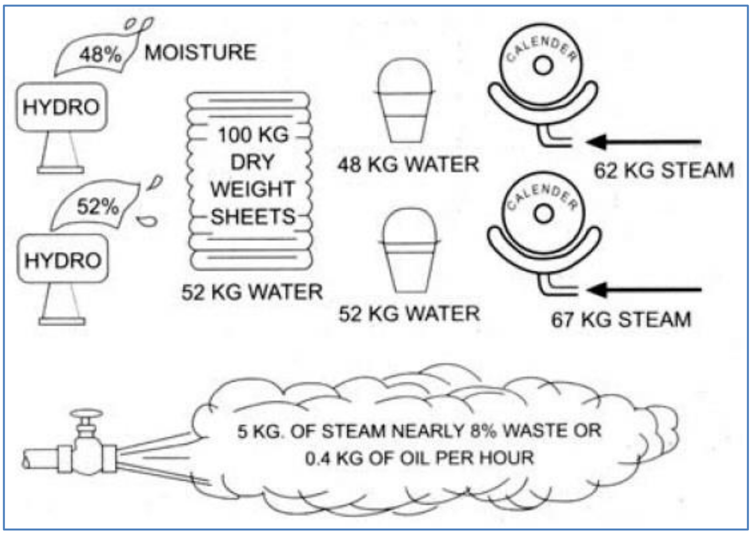


Figure 3.23 Steam Wastage due to Insufficient Mechanical Drying

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 percent. This is illustrated in Figure 3.23.

Examples

Problem-6:

In a crude distillation unit of a refinery, 50 TPH 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 @ PKR 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?

a) Utilizing 3 bar steam
b) Utilizing 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

Solution:

Heat gain in crude = m * Cp * ΔT

Heat gain in crude = 50 * 1000 * 0.631 * (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 * 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 * 8000 * 4.5

Cost of steam expenditure = PKR 1.098 Million

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 * 8000 * 4.5

Cost of steam expenditure = PKR 11.61 Million

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/cm^2 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/cm^2 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/cm^2 = 450 kCal/kg

Solution:

Quantity of heat available above saturation = 20,000 x 0.45 x (280-210)
= 630,000 kCal

Quantity of water required in de-superheater = Q x {1x (210-30) + 450} = 630,000
= 1000 kg/hr

Chapter 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, furnaces can be classified 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.

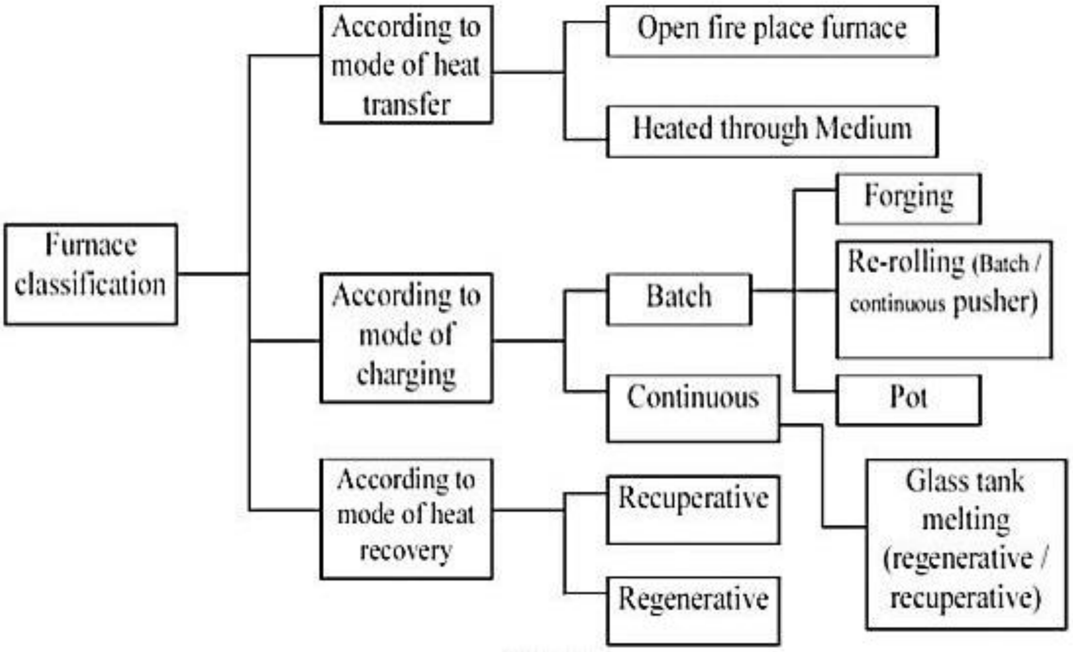


Figure 4.1: Furnace Classification

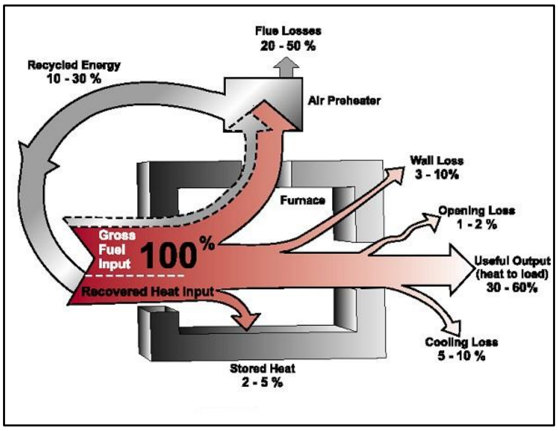
The electric furnaces can be broadly classified as resistance type for heating and induction and arc furnace for melting of metals.

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.
- Equalization of temperature within 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 with 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 cast iron. 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 and prepare it for additional processing or change its properties. This results in energy losses in different areas and forms as shown in below San-key diagram.

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 surroundings by radiation and convection from outer surface of the walls
4. Heat loss through gases leaking through cracks, openings and doors.

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.

$$Thermal\ efficiency\ of\ furncae = \frac{Heat\ in\ stock}{Heat\ in\ fuel\ consumed\ for\ heating\ stock} \times 100$$

The quantity of heat to be imparted (Q_f) to the stock can be found from the following relation;

$$Q_f = m \times C_p \times (t_1 - t_2)$$

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

Heat in fuel = Quantity of fuel (q) in kg/h x GCV in kCal/kg

Example -1:

The following are the operating parameters of rerolling mill furnace

Weight of input material	- 10 TPH
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 %

a. Calculate furnace efficiency by direct method

b. Calculate Specific fuel consumption on finished product basis

Solution:

a) Furnace efficiency by direct method

Heat input: 600 x 0.92 x 10000

= 5,520,000 kCal/hr

Heat output: 10,000 x 0.12 x (1200 – 40)

= 1,392,000 kCal/hr

Efficiency: 1,392,000 /5,520,000

= **25.2 %**

b) Specific fuel consumption on finished product basis

Weight of finished products:	10 x 0.92 = 9.2 TPH
Furnace oil consumption:	600 litres/hr
Specific fuel consumption	600/9.2 = **65.2 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 ton 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.

Parameter		Value
Specific gravity of oil	=	0.92
Average fuel oil consumption	=	400 litres/h 400x0.92 = 368 kg/h
Theoretical air	=	14.12 kg of air/kg of oil
O2 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	**=**	$\frac{O_2 \%}{21\ O_2 \%}$ **x100 [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 (TPH)
	=	368 / 6
	=	61.33 kg of fuel / tonne of billet

2) Calculation of Heat Input:

Combustion heat of fuel	**=**	**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 (Q2)	=	F x Cp fuel [tf - ta]
	=	61.33 x 0.5 x (100 – 40)
	=	1840 kCal/tonne of billet
Total heat input	=	Q1 + Q2
	=	6,13,300 + 1840
	=	6,15,140 kCal/tonne of billet

3) Calculation of Heat Output:

Heat carried by 1 tonne of billet (Q3)	**=**	**$1000\ kg/t \times C_p \times (T_0 - T_i)$**
	=	**1000 x 0.12 x (1340 – 40)**
	=	**1,56,000 kCal/tonne of billet**
Heat loss in dry flue gas per tonne of billet (Q4)	=	$F \times m \times C_{pfg}\ [t_1 - t_a]$
	=	61.33 x 32.86 x 0.26 x [650 – 40]
	=	3,19,627 kCal/tonne of billet
Heat loss due to formation of water vapour from fuel per tonne of billet (Q5)	=	$F \times M \times \{584 + C_p$ of superheated vapour $\times [t_1 - t_a]\}$
	=	61.33 x 1.084 x {584 + 0.47 x (650 – 40)}
	=	57,886 kCal/tonne of billet
Heat loss due to moisture in combustion air (Q6)	=	$F \times AAS \times$ Humidity of air $\times C_p$ of superheated vapour $\times [t_1 - t_a]$
	=	61.33 x 32.94 x 0.03437 x 0.47 x (650 – 40)}
	=	19,907 kCal/tonne of billet
% Heat loss due to partial conversion of C to CO (Q7)	=	$F \times \dfrac{\%CO \times C}{\%CO \times \%CO_2} \times 5654$
	=	$61.33 \times \dfrac{0.005 \times 0.859}{0.005 \times 6.5} \times 5654$
	=	229 kCal/tonne of billet
Amount of heat loss from the furnace body and other sections (Q8)	=	$(q_1 + q_2 + q_3 + q_4)$, kCal/hr / Amount of billet (TPH)
where,		
q_1, Heat loss from the furnace body ceiling surface (horizontal surface facing upward)	=	$\{h \times \Delta t^{1.25} \times A_i\} + \{4.88 \times \varepsilon \times [(T_w/100)^4 - (T_a/100)^4] \times A_i\}$
where,		
H	=	Natural convection heat transfer rate 2.8 (kCal/m^2 h ^{o}C)
Δt	=	$T_w - T_a$ = 358 – 313 = 45
E	=	Emissivity of the furnace body surface (0.75)
q1	=	$\{2.8 \times 45^{1.25} \times 15\} + \{4.88 \times 0.75 \times [(358/100)^4 - (313/100)^4] \times 15\}$
	=	8644 kCal/hr

Heat carried by 1 tonne of billet (Q3) = **1000 kg/t x Cp x (T0 –Ti)**
= **1000 x 0.12 x (1340 – 40)**
= **1,56,000 kCal/tonne of billet**

q2, Heat loss from the furnace body sidewall surfaces (vertical surfacing sideways) = {h x $\Delta t^{1.25}$ x Ai} + {4.88 x ε x [$(Tw/100)^4$ – $(Ta/100)^4$] x Ai}

where,

H = Natural convection heat transfer rate 2.2 (kCal/m^2 h ^{o}C)

Δt = Tw - Ta = 373 – 313 = 60

q2 = {2.2 x 601.25 x 36} + {4.88 x 0.75 x [(373/100)4 – (313/100)4] x 36}
=

q3, Bottom (horizontal surface facing downward) = As the bottom surface is not exposed to the atmosphere, q3 is ignored in this calculation

q4, Heat loss from the flue gas duct between furnace exit and air preheater (including heat loss from external surface of APH) = {h x Δt1.25 /D0..25 x Ai}+ {4.88 x ε x [$(Tw/100)^4$ - (Ta/100)4] x Ai}

where,

H = Natural convection heat transfer rate 1.1 (kCal/m2 h oC)

Δt = Tw - Ta = 337 – 313 = 24°K

E = Emissivity of the furnace body surface (0.75)

q4 = [1.1 x 241.25/0.40.25 x 10.3] + {4.88 x 0.75 x [(337/100)4 – (313/100)4] x 10.3}
= 2001 kCal/hr

Q8 = (q1 + q2 + q3 + q4), kCal/hr / Amount of billet (TPH)
= (8644 + 26084 + 0 + 2001)/6
= 6,122 kCal/t

Radiation heat loss through furnace openings (Q9) = hr x A x φ x 4.88 [(Tf/100)4 – (T0/100)4] / Amount of billet

Where,

Hr = Open time during the period of heat balancing

A = Area of an opening in m2 = 1 m2

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))

Heat carried by 1 tonne of billet (Q3) **= 1000 kg/t x Cp x (T0 –Ti)**
= 1000 x 0.12 x (1340 – 40)
= 1,56,000 kCal/tonne of billet

Q9 = 1 x 1 x 0.70 x 4.88 x [(1613/100)4 – (313/100)4] / 6
= 38,485 kCal/t

Other unaccounted heat losses (Q10) = 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

Q10 (unaccounted losses) = (Q1 + Q2)- (Q3 + Q4 + Q5 + Q6 + Q7 + Q8+ Q9)
= (6,15,140) - (1,56,000 + 3,19,627 + 57886+ 19,907 + 229 + 6,122 + 38,485)
= 16,884 kCal/t

Total heat output = Q3 + Q4 + Q5 + Q6 + Q7 + Q8+ Q9 + Q10
1,56,000 + 3,19,627 + 57886+ 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 (Q1)	***6,13,300***	99.70	***Heat carried away by 1 tonne of billet (Q3)***	***1,56,000***	***25.4***
Sensible heat of fuel (Q2)	1,840	0.30	Heat loss in dry flue gas per tonne of billet (Q4)	3,19,627	52.0
			Heat loss due to formation of vapour from fuel per tonne of billet (Q5)	57,886	9.4
			Heat loss due to moisture in combustion air (Q6)	19,907	3.2
			% Heat loss due to partial conversion of C to CO (Q7)	229	0.04
			Amount of heat loss from the furnace body and other sections (Q8)	6,122	1.0
			Radiation heat loss through furnace openings (Q9)	38,485	6.26
			Unaccounted losses (Q10)	16,884	2.7
Total	**6,15,140**	**100**		**6,15,140**	**100**

5. Efficiency of furnace (by direct method)

$$\eta_{furnace} = \frac{\text{Heat carried away by billet, kCal/hr}}{\text{Combustion heat of fuel, kCal/hr}} \times 100$$

$$= [(6000 \text{ kg/hr} \times 0.12 \text{ kCal/kg } ^0\text{C} \times (1340 - 40)\ ^0\text{C}] \times 100 \,/\, [368 \text{ kg/hr} \times 10000 \text{ kCal/kg}]$$

$$= 25.4\%$$

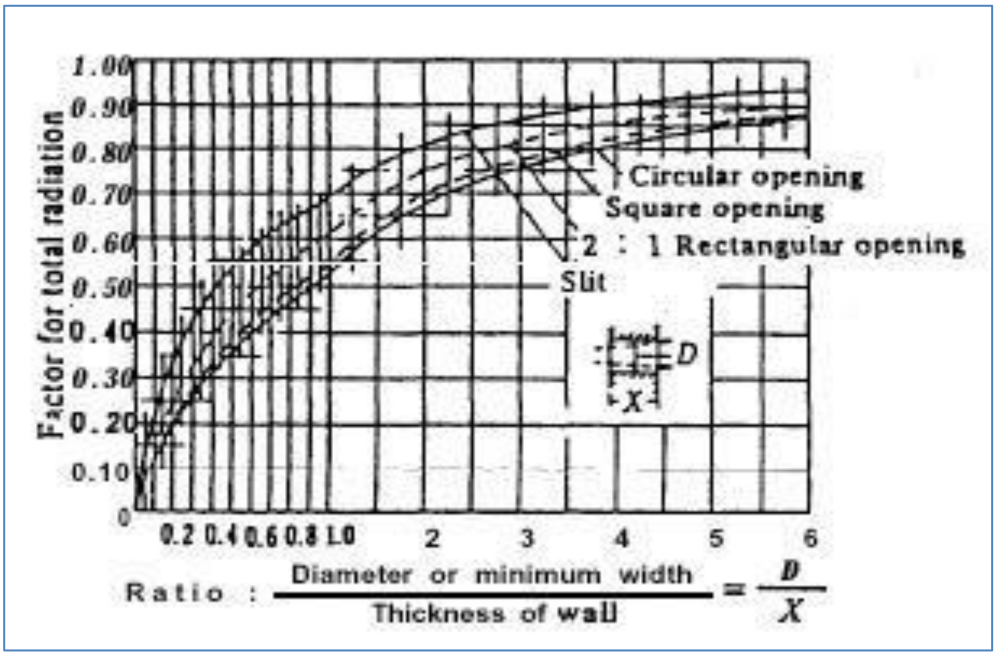


Figure 4.2: Factor for determining the equivalent of heat release from openings to the quality of heat release from perfect black body

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^{O}C
2.	Flue gas	Flue gas exit from furnace and entry to recuperator	Chromel Alummel Thermocouple with indicator	700^{O}C max.
3.	Flue gas	After recuperator	Hg In steel Thermometer	300^{O}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.	O2% = 5 t = 700^{O}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 flue gases
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 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 fuel carried away by waste
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, maintain fuel quality and monitor excess air.

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 4.3 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. Figure 4.4 shows a typical example of a reheating furnace equipped with an automatic air/fuel ratio controller.

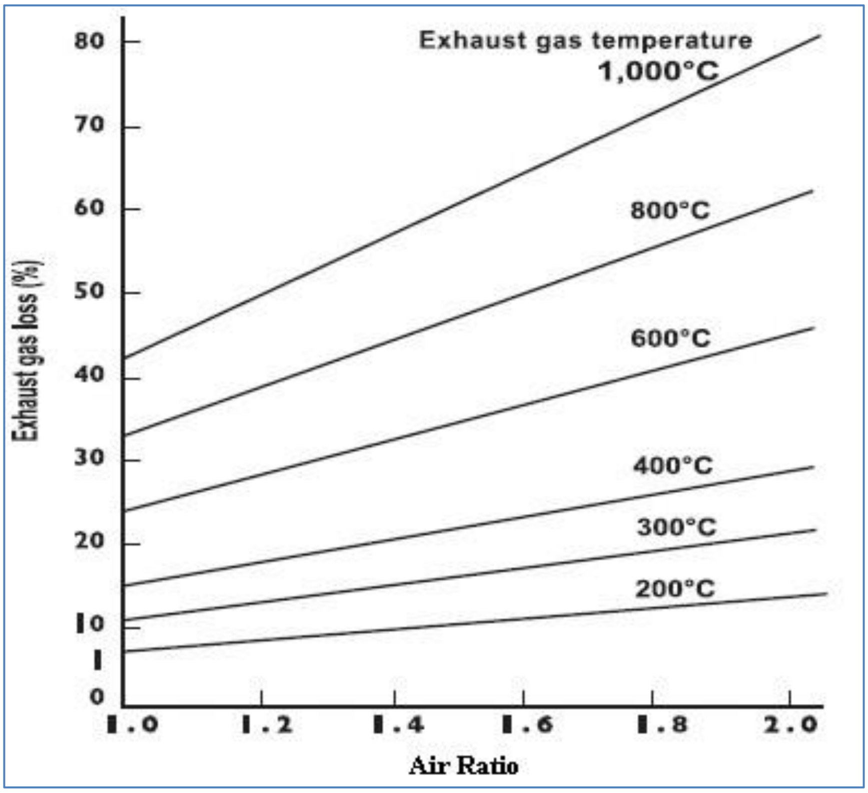


Figure 4.3: Relation between air ratio and exhaust gas

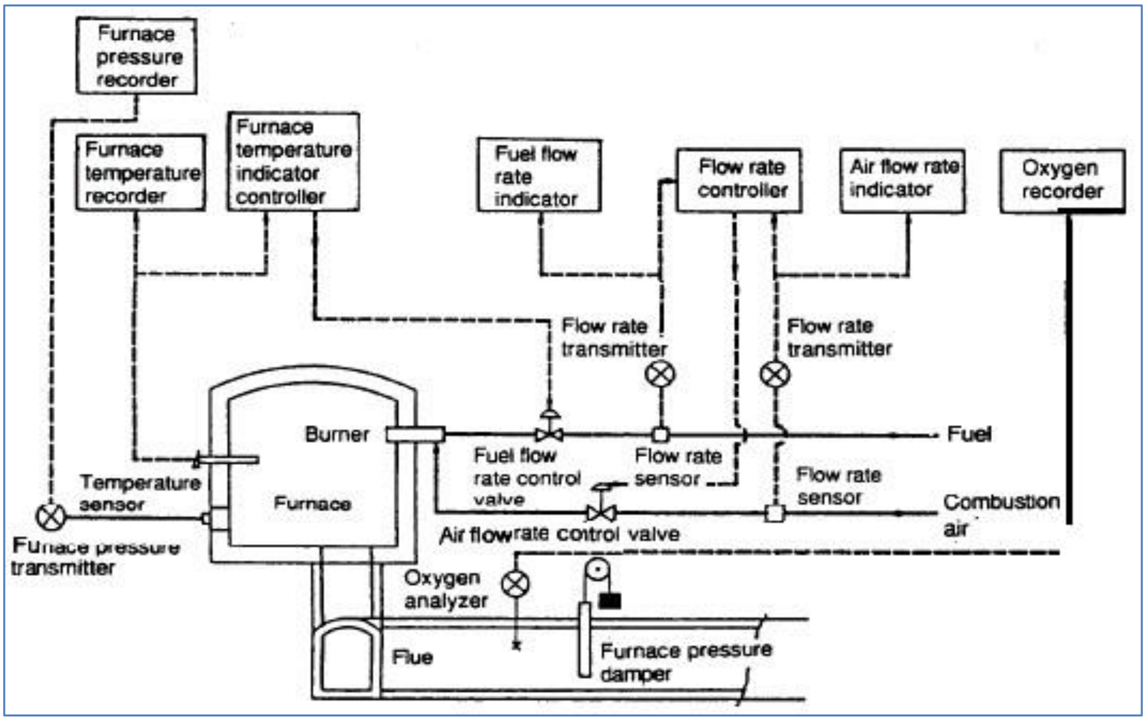


Figure 4.4: Air/fuel ratio control system with flow rate controller

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-atomize 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 4.5 and 4.6).

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.

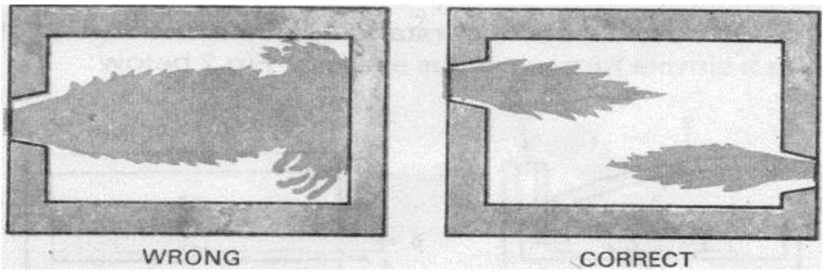


Figure 4.5: Heat Distribution in Furnace

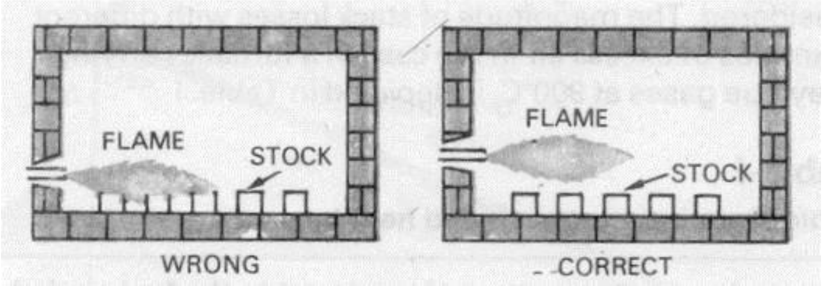


Figure 4.6: Alignment of Burners in Furnace

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 ^{O}C**
Rolling Mill furnaces	1200 ^{O}C
Bar furnace for Sheet Mill	800 ^{O}C
Bogey type annealing furnaces	650 ^{O}C -750 ^{O}C

Operating at too high temperatures than optimum causes heat loss, excessive oxidation, de-carbonization 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:

$$Q = 4.88 \times (\frac{T}{100})^4 \times a \times A \times H$$

Where,

T : Absolute temperature (K)
A : Area of the opening, m2
a : Factor for total radiation
H : Time (Hour)

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 = l/0.46 = 2.17. Thus, the factor for total radiation is 0.71 (refer Figure 4.3) and we get,

$$Q=4.88 \text{ x } ((1340+273)/100)^4 \text{x}0.71\text{x}1= 234{,}500 \text{ kCal/hr.}$$

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 likely 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 4.7.

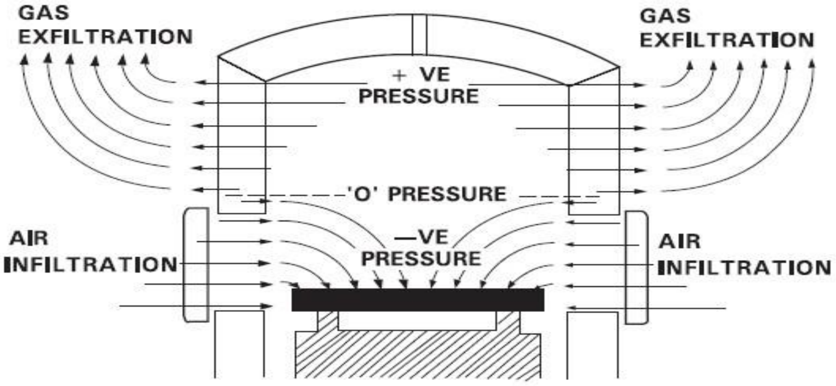


Figure 4.7: Effect of pressure on the location of zero level and infiltration of air

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 peep hole on furnace walls or the ceiling.

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 endeavor 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 in put 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 4.8).

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.

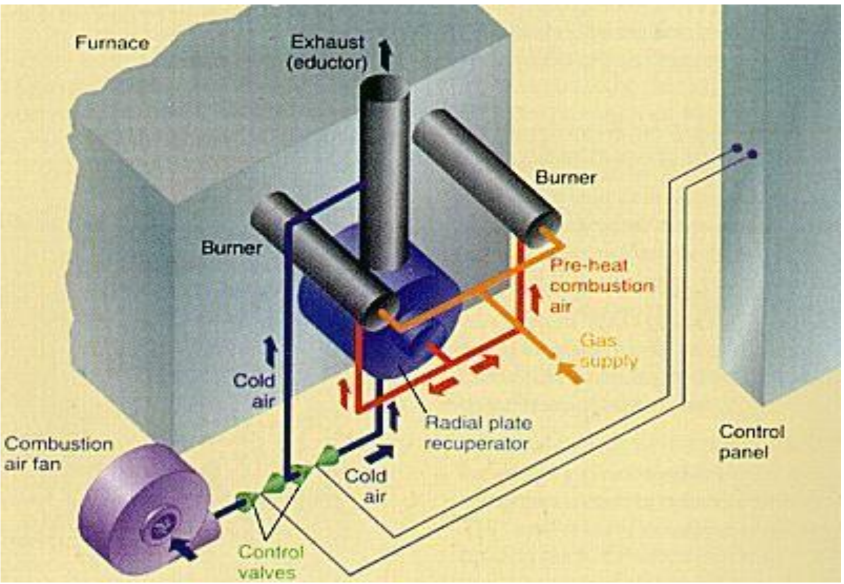


Figure 4.8: Preheating the air for combustion by a recuperator

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/kg of fuel)
P : Quantity of heat brought in by preheated air (kCal/kg of fuel)
Q : Quantity of heat taken away by exhaust gas (kCal/kg of fuel)

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 4.90 and Figure 4.10.

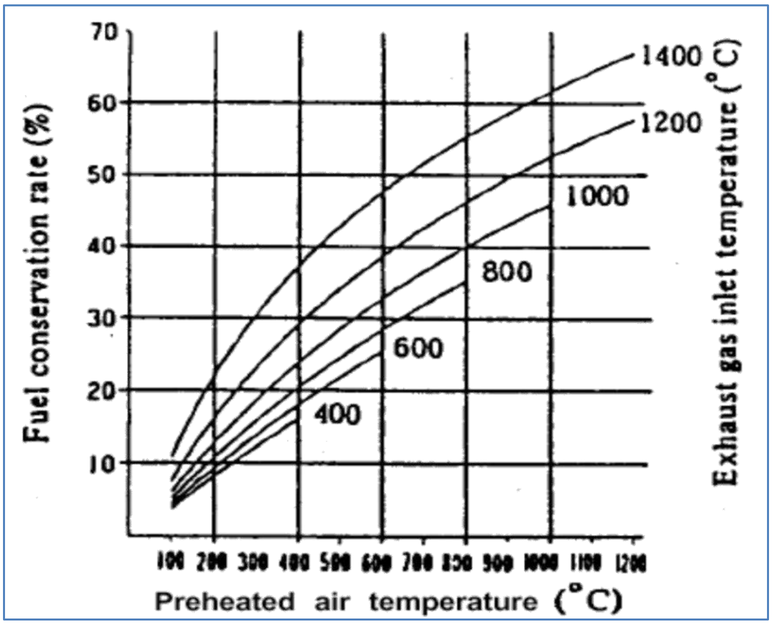


Figure 4.9: Fuel conservation rate when oil is used

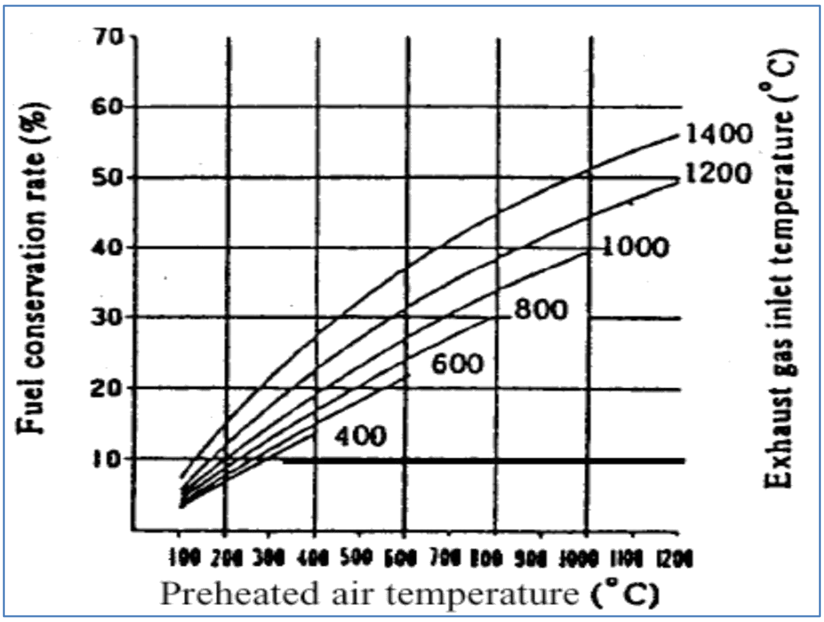


Figure 4.10: Fuel conservation rate when natural gas is used

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 5-10mm H_2O. 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 H_2O 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 increases 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 recuperator**	**Flue installation**	Convective: multi tubular, other	1000 or below	300 – 600	Heating furnace, heat treatment furnace and other industrial furnaces
		Chimney installation	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 make up for heat losses in intermittent or continuous furnaces. The appropriate choice of refractory and insulation materials goes a long 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 55 percent of the heat stored in the refractories 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 released from a reheating furnace is calculated with the following formula:

$$Q = a \times (t_1 - t_2)^{5/4} + 4.88E \times ((\frac{t_1 + 273}{100})^4 - (\frac{t_2 + 273}{100})^4)$$

Where,

Q : Quantity of heat released, (kCal/h/m2)

a : Factor regarding direct of the surface of natural convection ceiling = 2.8

Side wall = 2.2

Hearth = 1.5

T1 : Temperature of external wall surface of furnace (°C)

T2 : Temperature of air around the furnace (°C)

E : Emissivity of external wall surface of 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 4.11 shows the relation between the temperature of external wall surface and the quantity of heat release calculated with this formula.

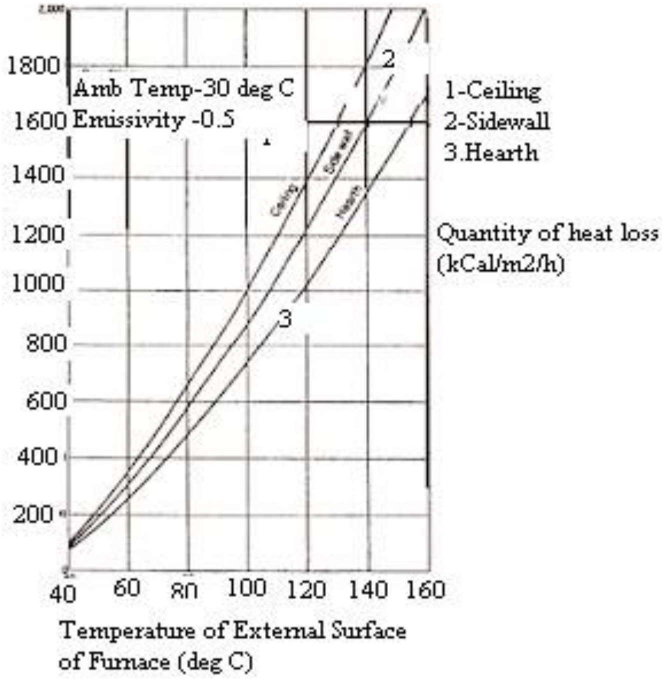


Figure 4.11: Quantity of heat released at various temperatures

This is explained with an example as follows:

Example-4: There is a reheating furnace whose ceiling, side walls and hearth has 20 m^2, 50 m^2, and 20 m^2 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.

From the above figure 4.12, the quantities of heat release from ceiling, side walls and hearth per unit area are respectively 650 kCal/m^2h, 720 kCal/m^2h, and 730 kCal/m^2h. Therefore, the total quantity of heat release is,

Q = (650x20) + (720x50) + (730x20) = 13000 + 36000 +14600= 63,600kCal/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. Figure 4.12 shows characteristics diagram of energy conservation for a fuel-fired furnace.

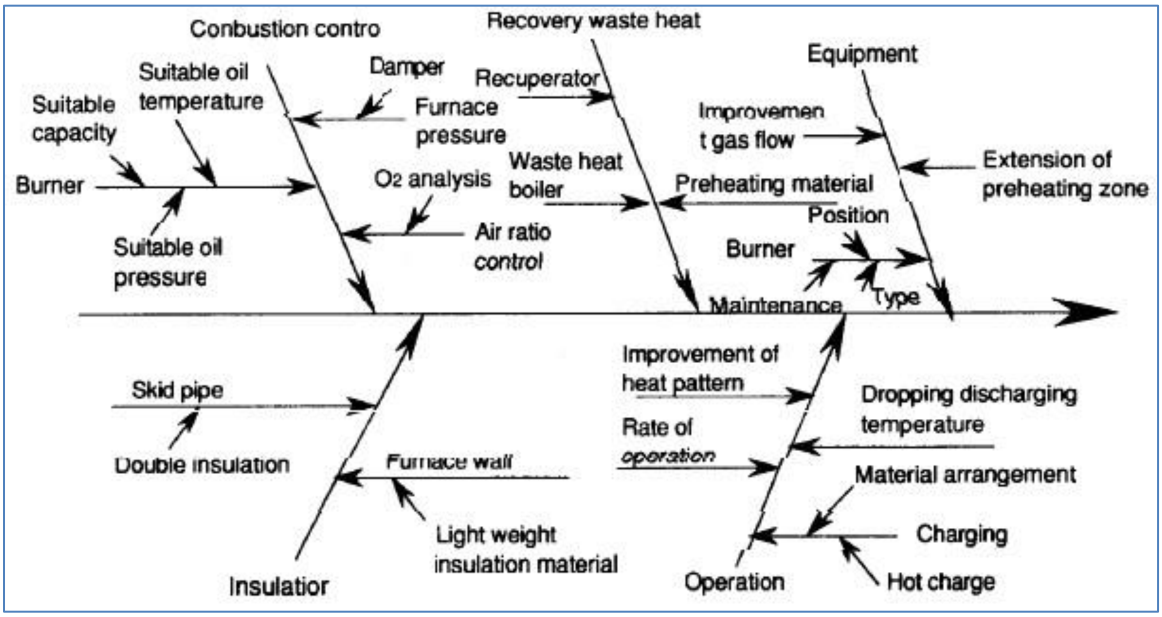


Figure 4.12 Characteristic Diagram of Energy Conservation for Reheating Furnace

4.4 Case Study

In a rerolling 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 savings 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. <u>During Starting</u>:

Savings by operating 2 nos. of LAP 4 A Wesman burners

30 minutes after starting up = 54 litres

b. <u>During Shutdown</u>:

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

Solution:

Theoretical energy required for melting = 1500 (0.682 x (1650 – 40) + 272)/3600 kWh
= 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 m^3/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 preheater (APH) to reduce the flue gas heat loss. The APH is designed to pre-heat 57TPH 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.

Solution:

Before the installation of APH

Heat gain by the crude = 500 x 1000 x 0.85 x 0.6 x (360-255)

= 26,775,000 kCal/hr

Heat input to the furnace = 3.4 x1000x 9850

= 33,490,000 kCal/hr

Efficiency of the furnace = 26,775,000 / 33,490,000

= 80 %

After the installation of APH

Heat gain by the crude = 500 x 1000 x 0.85 x 0.6 x (360-255)

= 26,775,000 kCal/hr

Heat gain by Air-preheater = 57 x 1000 x 0.24 x (195-28)

= 2,284,560 kCal/hr

Reduction in furnace input heat = Heat gained by Air-preheater

New Heat input to the furnace = 33,490,000 – 2,284,560

= 31,205,440 kCal/hr

Efficiency of furnace after installation of APH = 26,775,000 / 31,205,440

= 85.8 %

Induction Furnaces

Induction furnaces are ideal for melting and alloying a wide variety of metals with minimum melt losses, however, little refining of the metal is possible. There are two main types of induction furnace: coreless and channel, the principle of operation of which are the same.

Coreless Induction Furnace

Coreless induction furnace (Figure 4.13) consists of: a water cooled helical coil made of a copper tube, a crucible installed within the coil and supporting shell equipped with trunnions on which the furnace may tilt. Alternating current passing through the coil induces alternating currents in the metal charge loaded to the crucible. These induced currents heat the charge. When the charge is molten, electromagnetic field produced by the coil interacts with the electromagnetic field produced by the induced current. The resulted force causes stirring effect helping homogenizing the melt composition and the temperature.

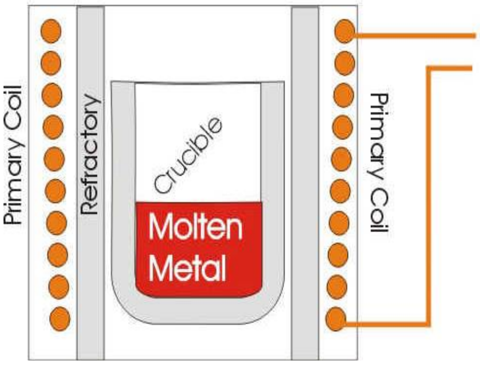


Figure 4.13 Coreless Induction Furnace

The frequency of the alternating current used in induction frequency (50 Hz or 60 Hz) to high frequency 10,000 Hz.

The total absolute energy required to melt one ton of different metals at different molten temperature is given in table 4.6.

Table 4.6 Energy required to melt one ton of different metals

Type of metal	Specific heat required	Latent heat required	Total require kWh/Ton
Mild steel @ 1650°C Melting temp.	1000 x 0.682 x 1620 ^{0}C ÷ 3600 ΔT = 1650-30 Cp = 0.9 kJ/kg ^{0}C = 307kWh	272 x 1000 ÷ 3600 kWh Latent Heat = 272 kJ/kg = 76 kWh	307 + 76 = 376 kWh
Aluminum @ 710 ºC Melting temp.	1000 x 0.9 x 680 ^{0}C ÷ 3600 kWh ΔT= 710 ^{0}C-30 ^{0}C Cp = 0.9 kJ/kg ^{0}C = 170 kWh	396.9 x 1000 ÷ 3600 kWh Latent Heat = 396.9 kJ/kg = 110 kWh	170 kWh + 110 kWh = 180 kWh
Copper @ 1130 ºC Melting temp.	1000 x 0.386 x 1100 ^{0}C ÷ 3600 kWh ΔT=1130 ^{0}C-30 ^{0}C Cp = 0.386 kJ/kg ^{0}C = 118 kWh	212 x 1000 ÷ 3600 kWh Latent Heat = 212 kJ/kg = 59 kWh	118 kWh + 59 kWh = 117 kWh
Gold @ 1130 ºC Melting temp.	1000 x 0.131 x 11300C ÷ 3600 kWh ΔT=1130 ^{0}C-30 ^{0}C Cp = 0.131 kJ/kg ^{0}C = 36.38 kWh	67.62 x 1000 ÷ 3600 kWh Latent Heat = 67.62 kJ/kg = 18.78 kWh	36.38 kWh + 18.78 kWh = 56 kWh

Furnace Efficiency

$$Efficiency,\% = \frac{Theoretical\ total\ heat\ required\ \ for\ melting\ (H_T),\ kWh}{Actual\ Electricity\ consumed\ \ for\ melting\ (H_A),\ kWh} \times 100$$

Theoretical heat required for melting (H_T)

$$Heat\ required\ \ for\ melting\ metal, H_1, kWh = \frac{W_m \times \left(C_p \times (T_2 - T_1) + h\right)}{3600}$$

(3600 kJ = 1 kWh)

$$Heat\ required\ \ for\ melting\ slag, H_2, kWh = \frac{1.65 \times W_s}{3.6}$$

(3.6 MJ = 1 kWh)

Where,

W_m - Weight of the metal, kg
W_s - Weight of the slag, kg
C_p - Specific heat of metal, kJ/kg °C
T_2 - Final temperature of the metal
T_1 - Initial or charge temperature of the metal

Total theoretical heat required for melting, $H_T = H_1 + H_2$

Actual electricity consumed for melting (H_A)

The actual consumption of electricity for melting can be measured from the input busbar to the furnace. The difference between Actual and theoretical values will be loss due to conduction, radiation and other losses.

Example – Melting of M.S. scrap

Calculate the furnace efficiency from the data given below

Specific heat	- 0.682 kJ/kg ^{0}C
Latent heat	- 272 kJ/kg
Melting temperature	- 1650 ^{0}C
Charge temperature	- 30 ^{0}C
Quantity of metal	- 1000 kg
Quantity of slag	- 25 kg
Electricity consumed	- 625 kWh

Solution

$$Heat\ required\ \ for\ melting\ metal, H_1, kWh = \frac{1000 \times \left(0.682 \times (1650 - 30) + 272\right)}{3600}$$

= 382.45 kWh

$$Heat\,required\;\;for\,melting\,slag, H_2, kWh\;\;=\frac{1.65\times 25}{3.6}$$

= 11.45 kWh

Total theoretical heat required for melting, H_T = 382.45 + 11.45

= 394 kWh

$$Efficiency, \% = \frac{394,\ kWh}{625,\ kWh}\times 100$$

= 63 %

Distribution of losses in induction furnace

Losses in induction furnace

The theoretical energy require to melt one Ton of steel is 385 TO 400 kWh/Ton. However in actual practice, the specific energy consumption is remarkably higher to 550 - 950 kWh/ton.

1. Power loss in generator / panel	= 2 - 4 %
2. Power loss in capacitor Bank	= 1.0 - 3 %
3. Power loss in Crucible (Water cooled cables, Bus bar, and change over switches)	= 18 - 25 %
4. Radiation loss	= 7 - 9%

Chapter 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)

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 (-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 (-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.

S. No.	Type of Insulation	Application	Characteristics
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 mats, 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 mats, 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** **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**	Suitable for 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	Suitable for many 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:

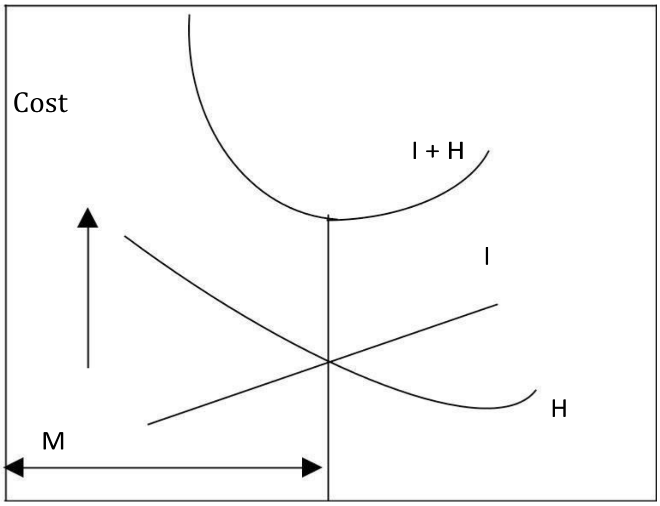
- Climate
- Type of fuel used
- The section that requires insulation

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



I: Cost of Insulation H: Cost of Heat Loss

I + H: Total Cost M: Economic Thickness

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 : Heat loss, Watts

h : Heat transfer coefficient, Watt/m^{2}K (2000 W/m^{2}K)

T_h : Hot surface temperature, °C and cold surface temperature, °C

T_a : Average ambient temperature, °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/hm^2

Ts : Hot surface temperature in °C

Ta : Ambient temperature in °C

$$Heat\ loss\ per\ hour\ {}^{kCal}/_{h} = S \times A$$

Where,

A : Surface area in m^2

Based on the cost of heat energy, the quantification of heat loss in PKR can be worked out as

$$Equivalent\ fuel\ loss, H_f(kg/year) = \frac{H_s \times Yearly\ hours\ of\ operation}{GCV \times \eta_b}$$

$$Annual\ heat\ loss\ in\ monetary\ tems = H_f \times Fuel\ cost\ (PKR/kg)$$

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 10,000kCal/liter is PKR 55/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,	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.

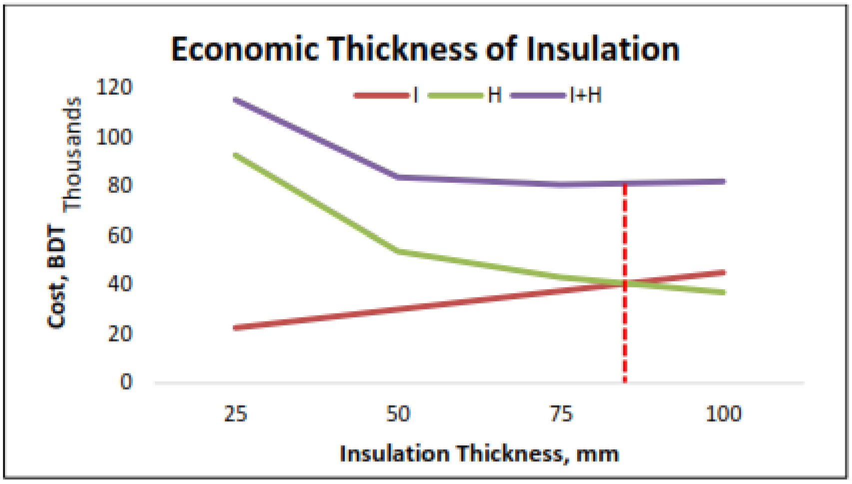
Step 8: Identify the economic thickness of insulating material by drawing a vertical line at the point of intersection of cost of insulating material and cost of fuel loss lines.

Economic thickness of insulation for 150 mm dia pipe

Steps	**Unit**	**Calculation**			
Step 1					
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	m^2	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		$S = [10 + \frac{T_s - T_a}{20}](T_s - T_a)$			

Economic thickness of insulation for 150 mm dia pipe					
-without insulation	kCal/hr.m2	2145			
-after insulation	kCal/hr.m2	551.25	319.2	256.45	220
Heat loss reduction	kCal/hr.m2	1594	1826	1888	1925
Step 3					
Total energy saved (Hs)	kCal/year	13387500	15336720	15863820	16170000
Yearly hours of operation	hrs	8400			
GCV	kCal/Lit	10000			
Boiler Efficiency	%	80			
$Equivalent\ fuel\ loss, H_f (kg/year) = \frac{H_s \times Yearly\ hours\ of\ operation}{GCV \times \eta_b}$					
Total fuel energy lost per year	Lit/year	370	215	172	148
$Fuel\ Savings = Fuel\ loss\ without\ insulation - Fuel\ loss\ with\ insulation$					
Yearly fuel savings	Lit/year	1071	1227	1269	1294
Step 4					
$Life\ cycle\ heat\ loss\ in\ monetary\ terms, PKR = H_f \times Life\ of\ insulation \times Fuel\ cost$					
Fuel Cost	PKR/Lit	55			
Cost of fuel loss					
-without insulation	PKR/5years	396396			
-with insulation [H]	PKR/ 5yrs	101871	58988.6	47392.4	40656
Step 5					
Cost of insulation	PKR/m	450	600	750	900
Total cost of insulation [I]	PKR	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 minimize 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 temperature 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 PCE[1] (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	28 - 30
Low duty refractories	19 - 28

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[1] *The 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°C. 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.*

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 (Chamottee)	Consists of kaolinite ($Al_2O_3.2SiO_2.2H_2O$) 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
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,	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 wettability against molten metal, low thermal conductivity, high corrosion resistance, high specific gravity	Nozzle for continuous casting, glass tank, high-temperature furnace, crucible.

Refractory Type	General Characteristics	Application
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, andualusite, 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	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		
Chrome	High refractoriness, low strength at high temperature, low thermal resistance	Buffer brick between acid and base brick

Refractory Type	General Characteristics	Application
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.

Kind	Definition
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 castables	These are porous lightweight materials which are mixed with hydraulic cement and water and formed by casting. Lightweight castables are used to line furnaces, kilns, etc.
Fibrous Materials	
Ceramic fiber	Ceramic fibre is an alumino-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. They are produced as 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

Temperatur	Al_2O_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.

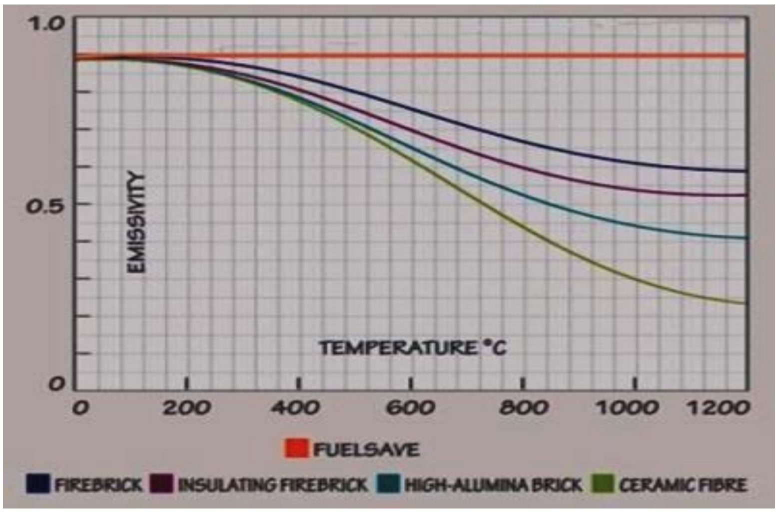


Figure 5.3: Emissivity of refractory materials at different temperatures

Furnaces, which operate at higher temperature, have emissivity of 0.3. By using high emissivity coatings this can go up to 0.8 thus effectively increasing the radiative heat transfer.

Chapter 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 TPH to 74TPH.

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.

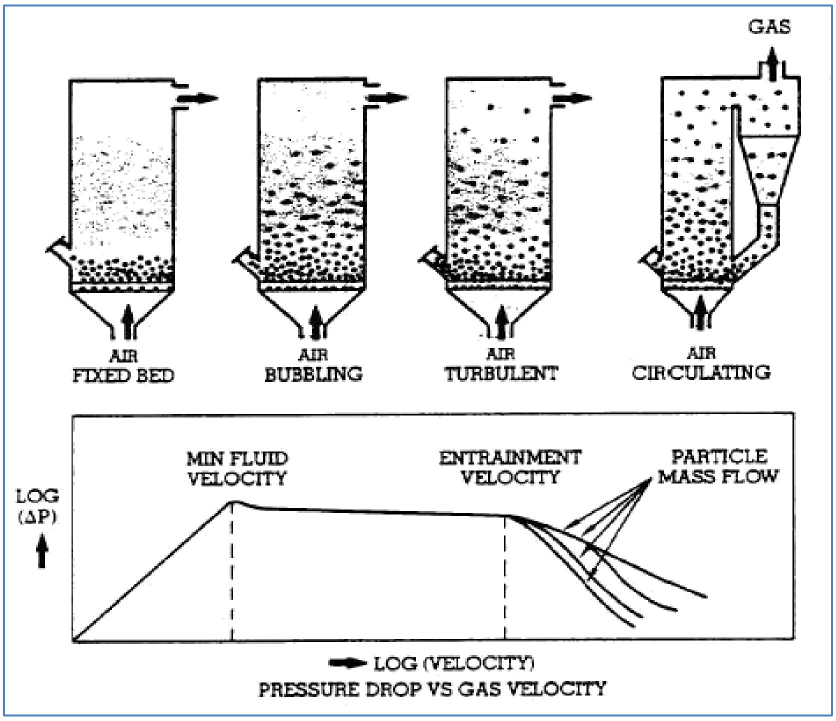


Figure 6.1: Principle of fluidization

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.

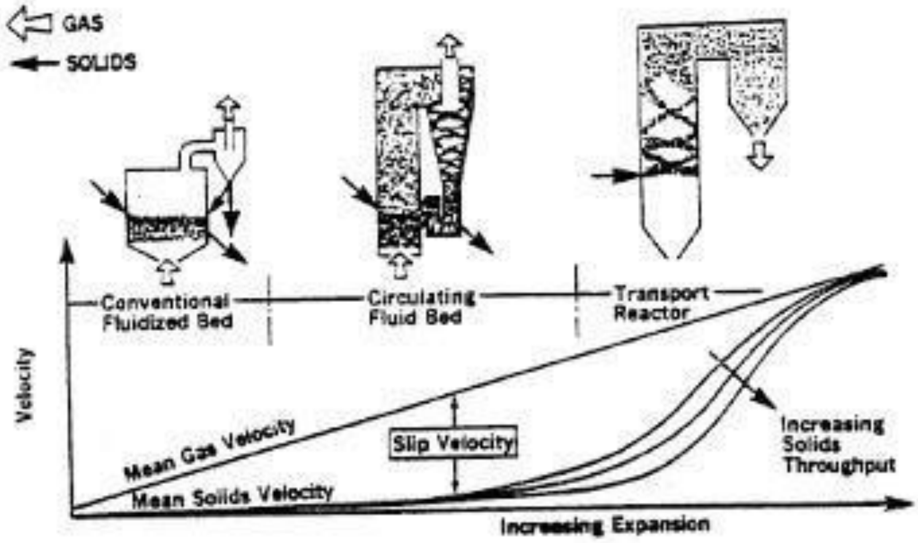


Figure 6.2: Relation between gas velocity and solid velocity

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.

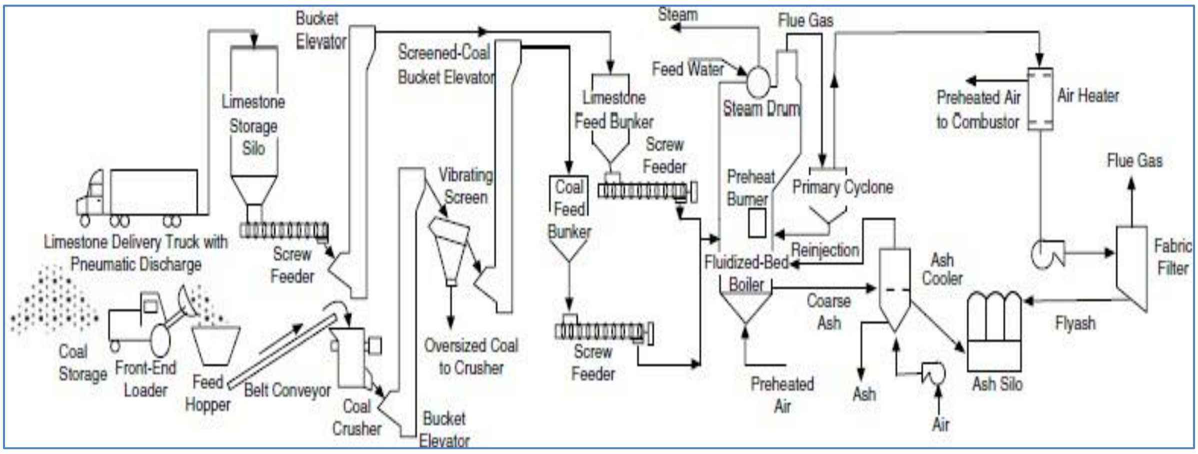


Figure 6.3: Typical fluidized bed boiler plant firing solid fuels

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 ithdrawal 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.

Under-bed and Over-bed

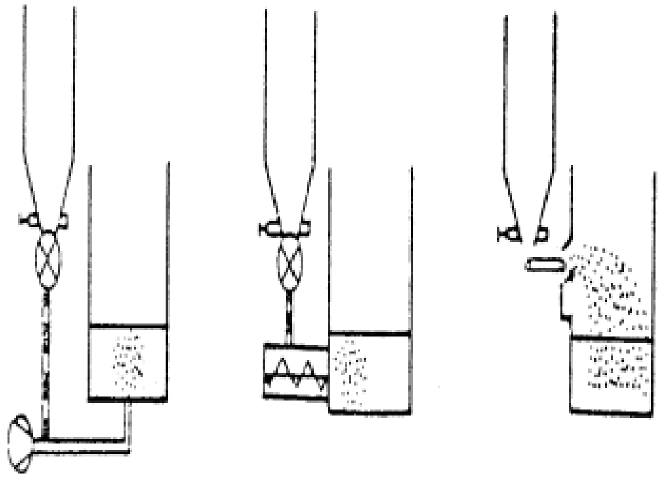


Figure 6.4: Types of Fuel Feeder

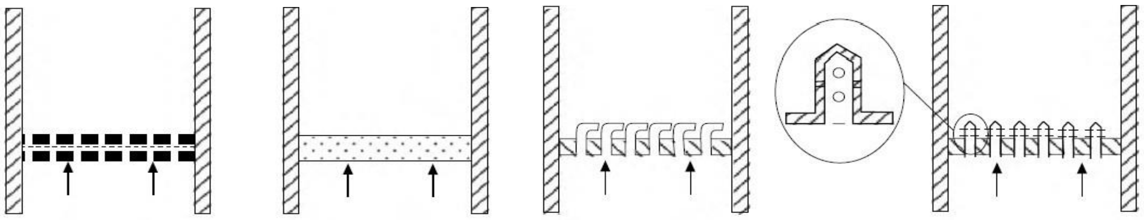
There are broadly four types of industrial feeders: gravity chute, screw feeder, spreader, and pneumatic feeders.

6.2.1.2 Air Movers

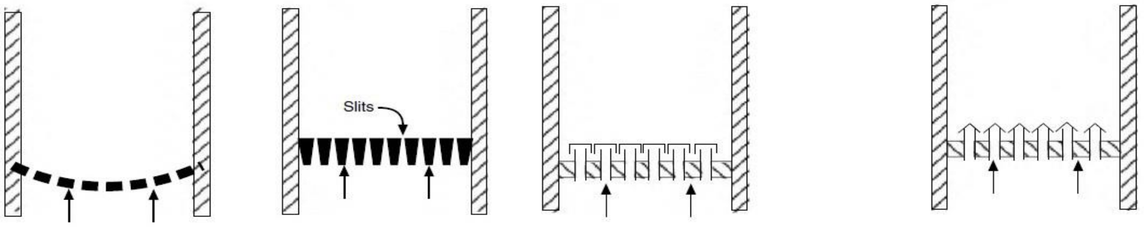
Air movers supply air for combustion and fluidization of the burning fluidized bed and pneumatic transportation of solid matters such as coal, limestone, and ash.

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 de-fluidization 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.



(a) Perforated Plates (b) Porous (a) Directional Nozzle (b) Simple Nozzle



(c) Dished Perforated (d) Grate Bars (c) Bubble Cap (d) Slit Nozzle

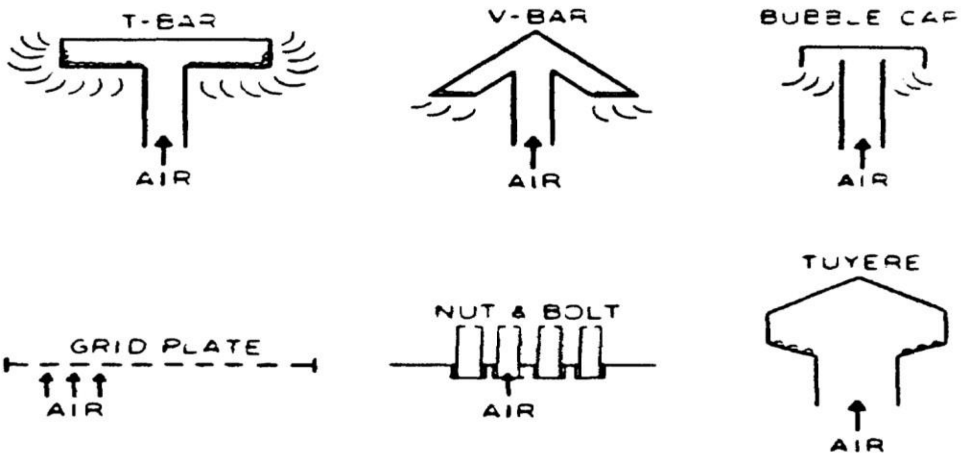


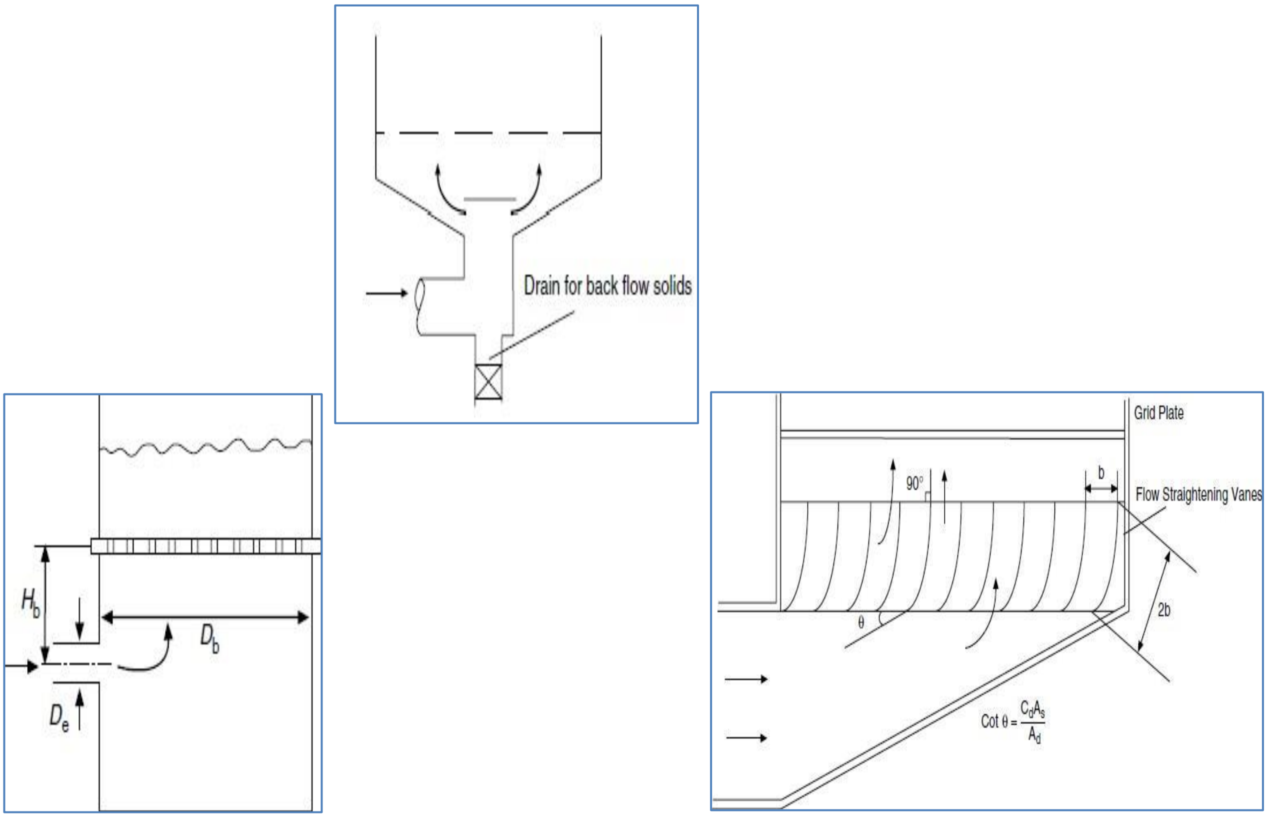
Figure 6.5: Air Distributors and Nozzles

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.



Air plenum with side-entry air

Flow-straightening vanes can help uniform distribution of air in the

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

- Bed pressure and temperature
- Superficial gas velocity
- Particle size,

- Heat exchanger design and
- 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 intermittently from the bottom to remove over size particles to avoid accumulation and consequent de-fluidization. While firing high ash coal such as washery rejects, the bed ash overflow 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 fluidization 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 preheater / 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.

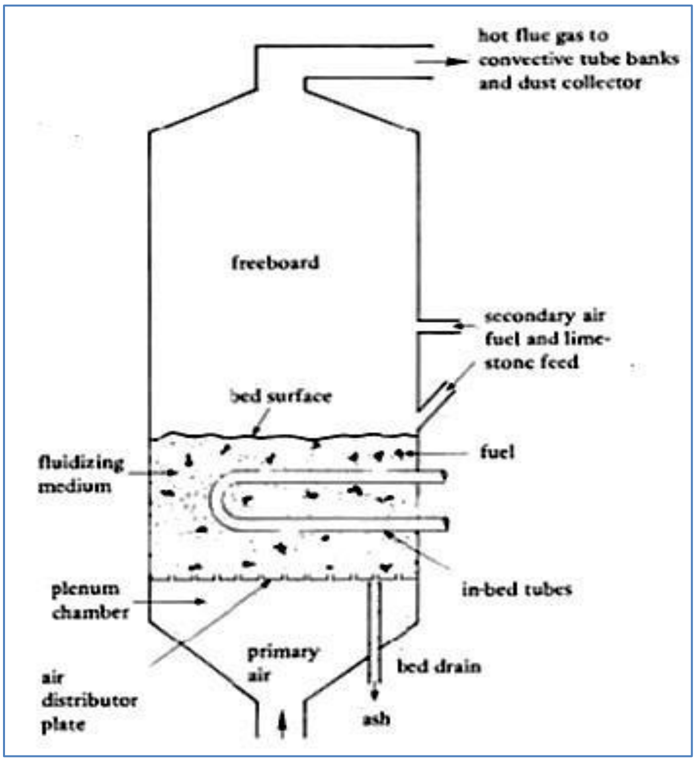


Figure 6.7: Conventional or Bubbling FBC showing components of FBC

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 these 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.

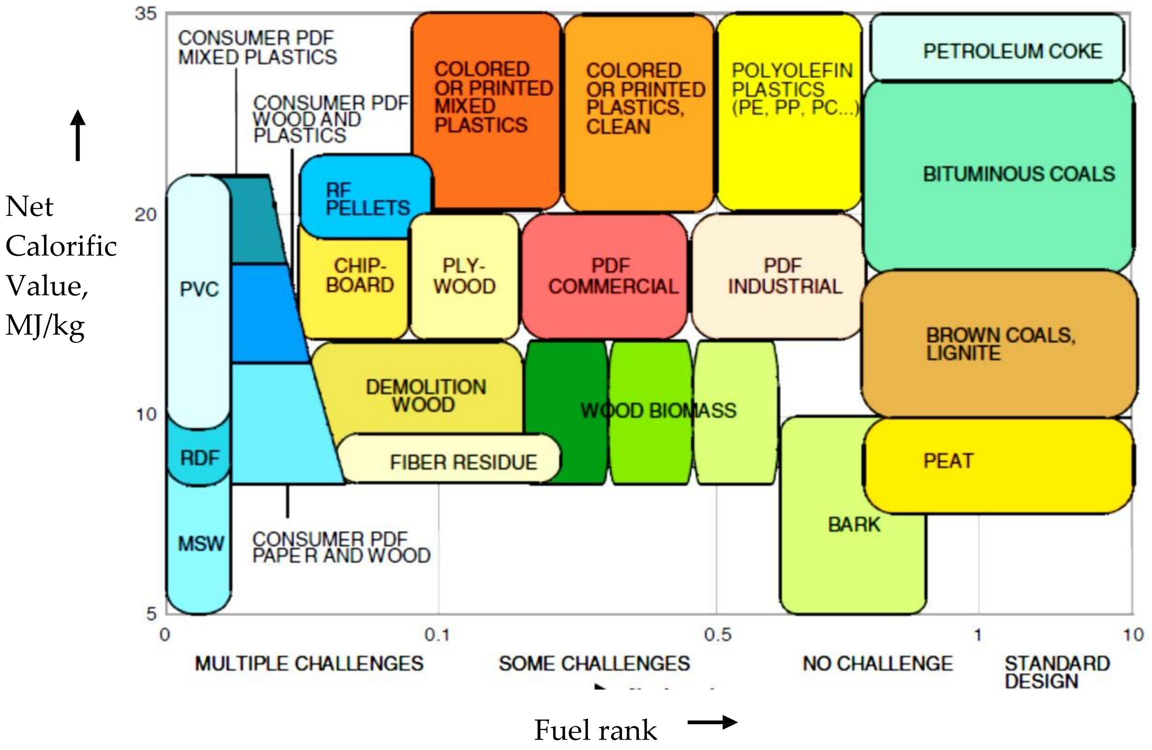


Figure 6.8: Fuels for FBC boiler and their Ease of Use

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 boiler emissions norms.

6.3.4 Economic Viability

The unique feature of FBC to burn inexpensive, low-grade, and high sulphur coals indicate a favorable 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 6.1: Summary of Advantages and Disadvantages of FBC Boilers

Advantages	Disadvantages
• Fuel flexibility • In situ SO2 removal • Low NOx 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 are given in Figure 6.9.

Site specific variables				Operating		Design variables		Operating		Economics
Emission Requirements Fuel availability • Type • Quality • Quantity Site specific components in case of: • Repower • Retrofit • Add-on • Conversion Application: • Combined Heat and • Process/space heating	→	Choice of echnology	→	• 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: o Economizer o Super-heater o Regenerator o Solids removal o Heat exchanger (for solids) Heat transfer surface o Tube size o Arrangement o Orientation Air distribution Location of draft fans o Primary air o Secondary air Solids handling Working fluid cycle (e.g. once through) Sulphur absorbent regenerator Refractory o Fuel feeding o Location o Number of points	→	Pollution control Combustion efficiency Sorbent utilization Fluidization Heat Transfer Elutriation Attrition Corrosion Erosion Agglomeration ash Control Turndown System efficiency o Thermal o 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 Fluidized Bed Combustion System (AFBC). BFB technology is well suited for utilization 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) Fluidized 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 fluidization velocity, which is higher for CFB compared to BFB.

The third variant is a hybrid type of the BFB and CFB and is called Pressurized Fluidized 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

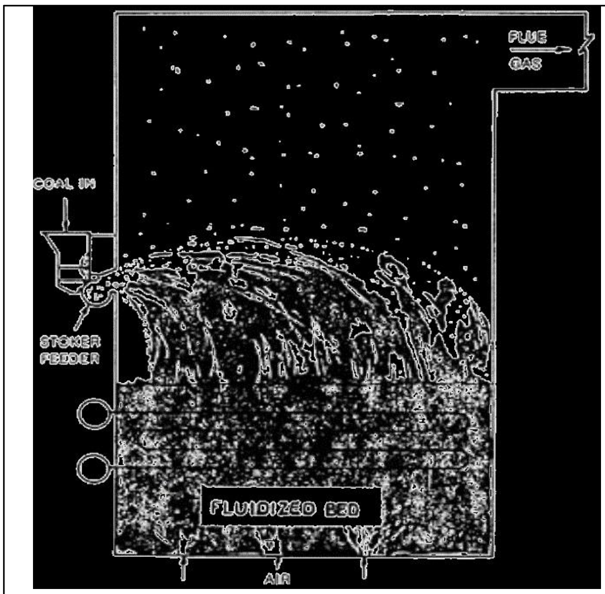
In this type of FBC, coal is crushed to a size of 1-10 mm depending on the rank of coal, type of fuel feeding and fed to the combustion chamber. The atmospheric air, which acts as both the fluidization air and combustion air, is delivered at a pressure, and flows through the bed after being preheated by the exhaust flue gases. The in-bed tubes carrying water generally act as the evaporator.

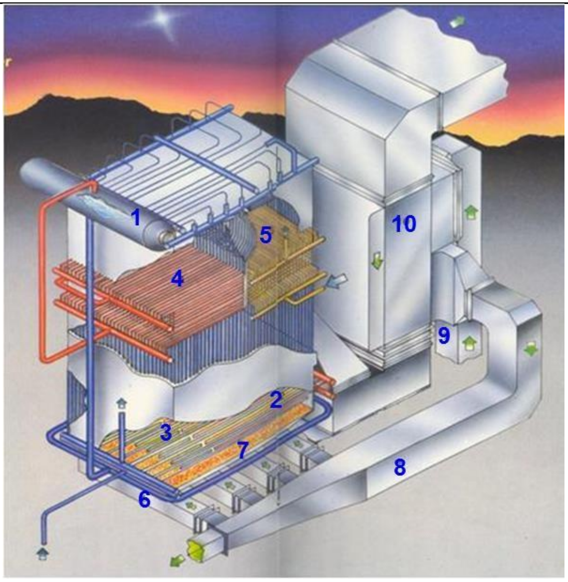
Fluidized bed combustion is to be done in a relatively narrow temperature range within which the bed must be operated. With coal, there is risk of clinker formation in the bed if the temperature exceeds 950°C and combustion efficiency declines below 800°C. For efficient sulphur retention the temperature 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.





1 Steam Drum ,2 Bed Super-heater, 3 Bed Evaporator, 4 Convection Super heater, 5 Economizer, 6 Wind box, 7 Air Distributor Plate, 8 Hot Air Duct, 9 Cold Air Duct, 10 Air Preheater

Figure 6.10: Bubbling bed boiler-1

Figure 6.11: Bubbling bed boiler-2

6.4.2 Circulating Fluidized 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 TPH 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 SO_2 capture, and easier application of staged combustion techniques for NOx 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 NOx 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 NOx formation.
- Sulfur present in the fuel is retained in the circulating solids in the form of calcium sulphate and 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.

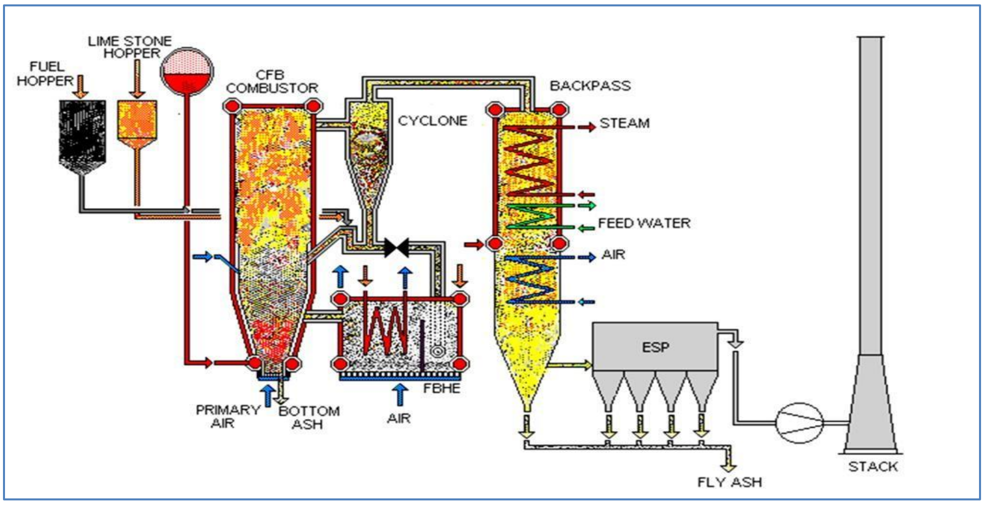


Figure 6.12: Circulating bed boiler design

Table 6.2: Comparison of BFBC and CFBC

Parameter	Units	BFBC	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	03-Oct
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	TPH	All sizes	45-680
Combustion Efficiency	%		2 - 3 % Better than BFBC
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

Pressurized 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).

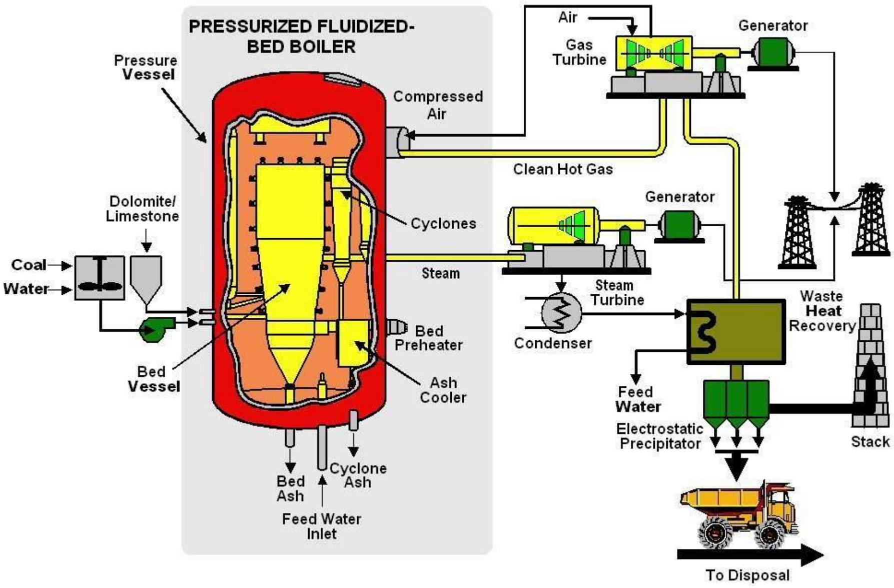


Figure 6.13: PFBC Boiler for Cogeneration

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.

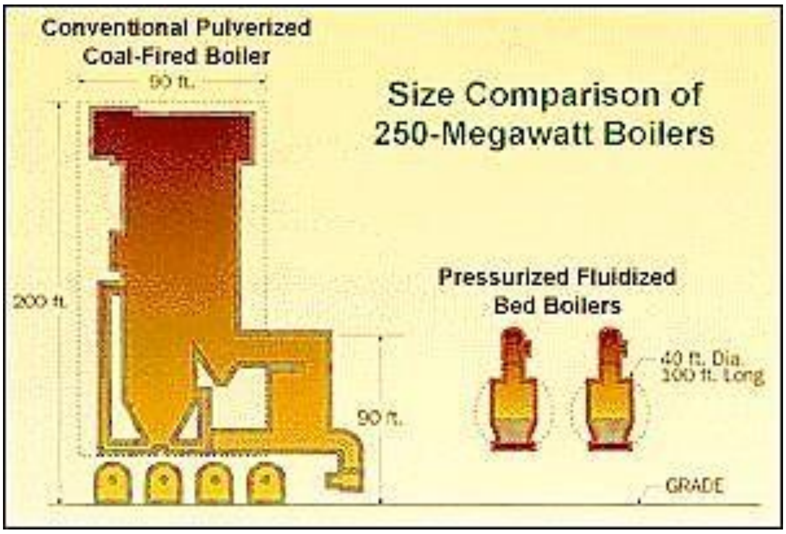


Figure 6.14: Comparison of PFBC boiler versus pulverized fuel boiler

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 underneath.
- 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.

Chapter 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.

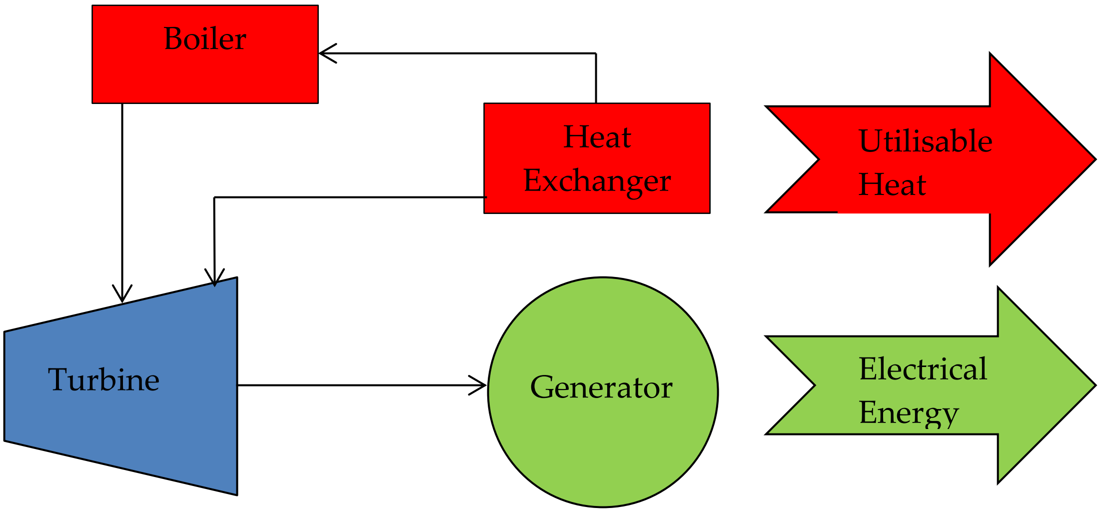
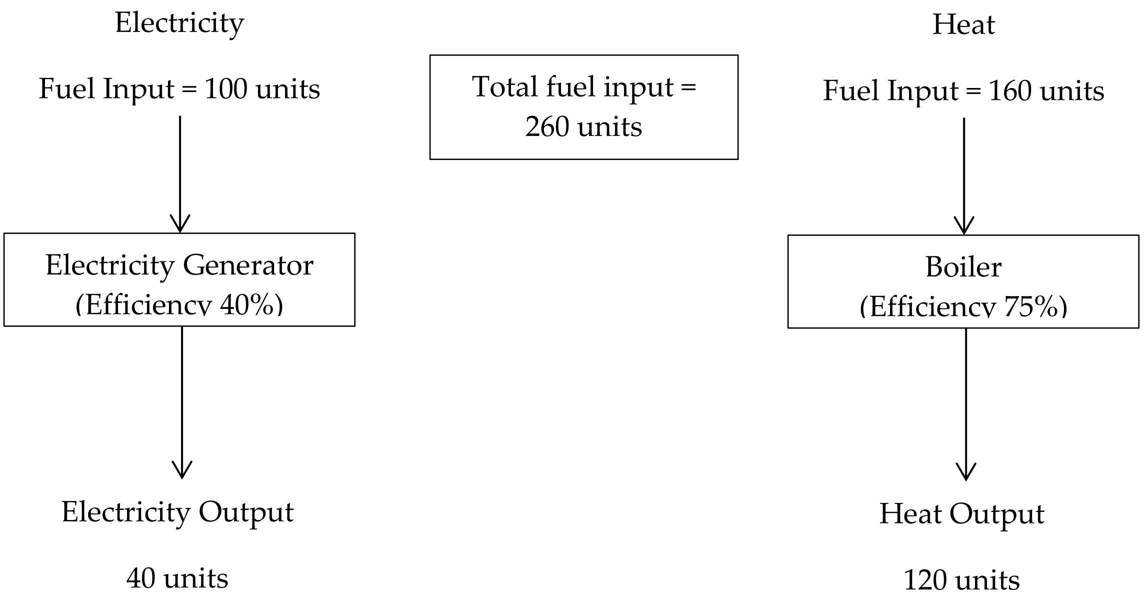


Figure 7.1: Cogeneration System

In cogeneration system, efficiencies can go up to 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 generation



Case B: Combined heat and power generation

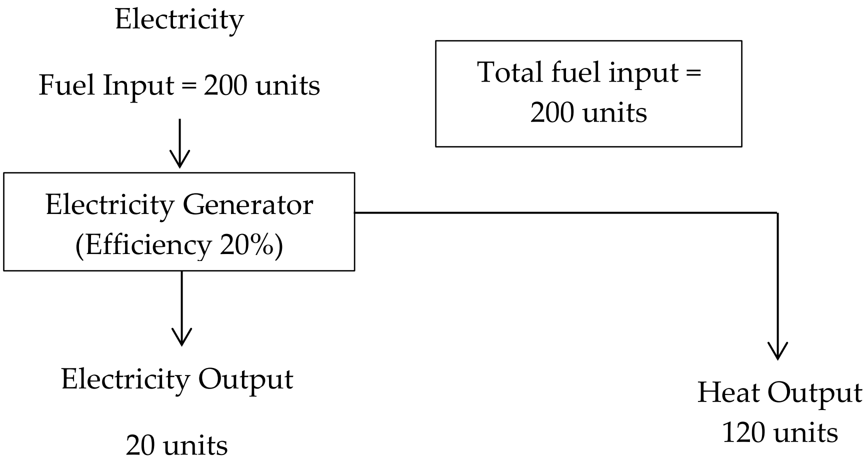


Figure 7.2: Comparison between energy inputs without and with cogeneration

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 at least 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:

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.
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. The process is shown in figure 7.3.

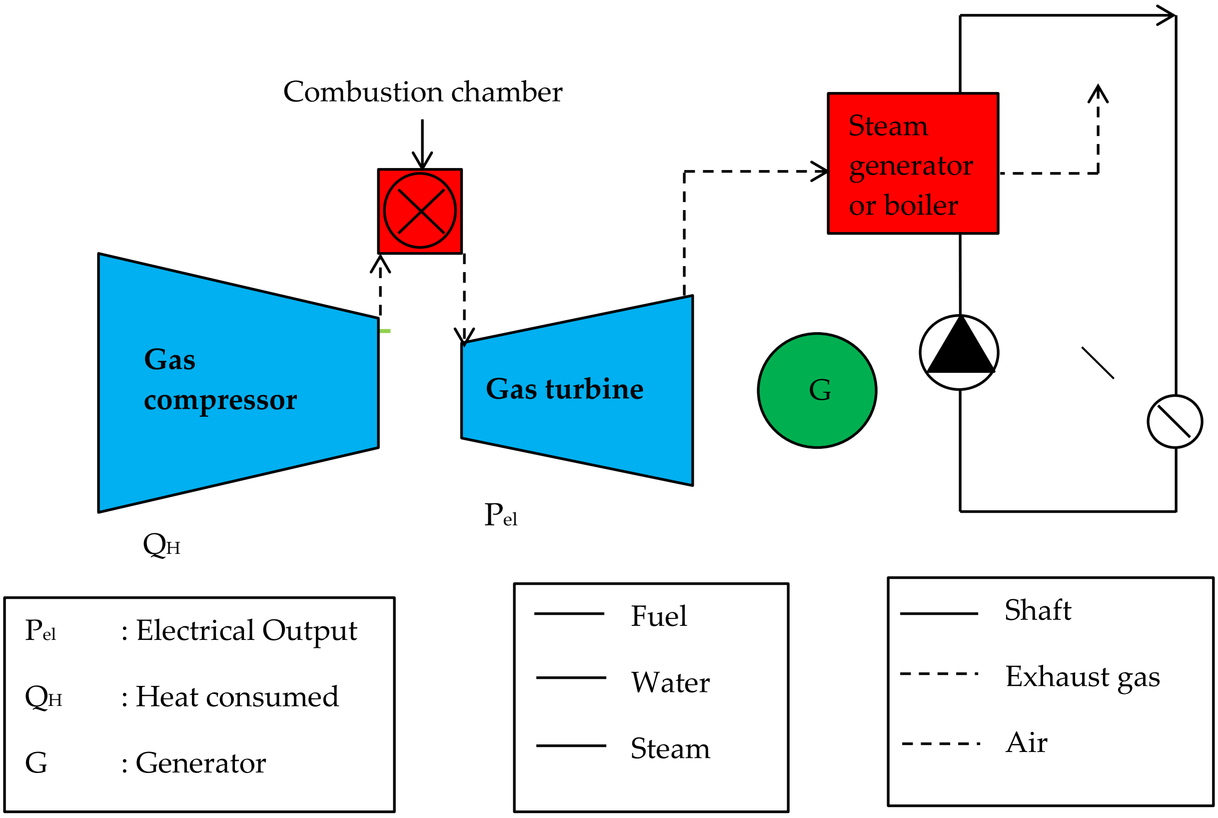


Figure 7.3: Gas turbine topping cycle

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. 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.

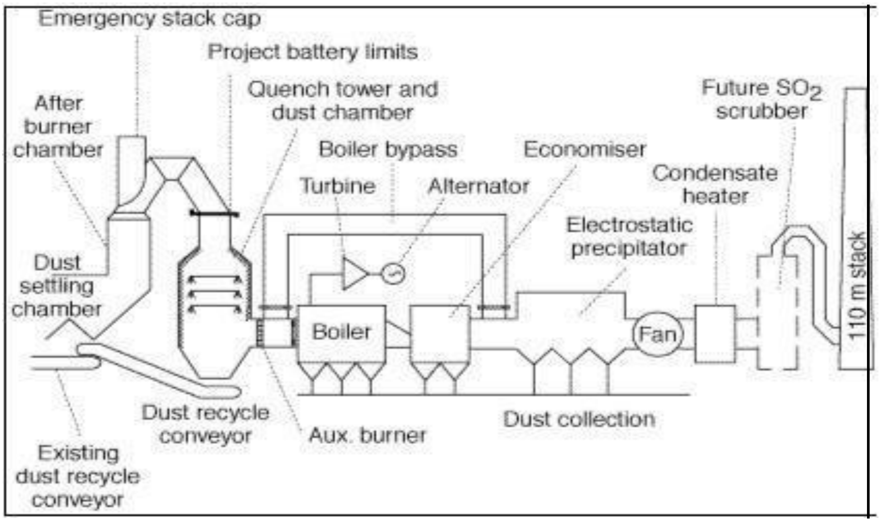


Figure 7.4: Bottoming cycle

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.

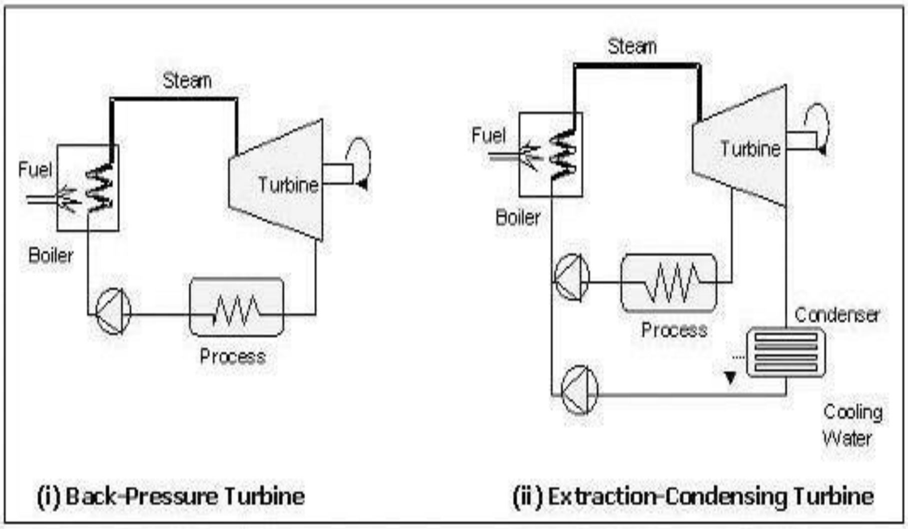


Figure 7.5: Steam turbine cogeneration system

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.

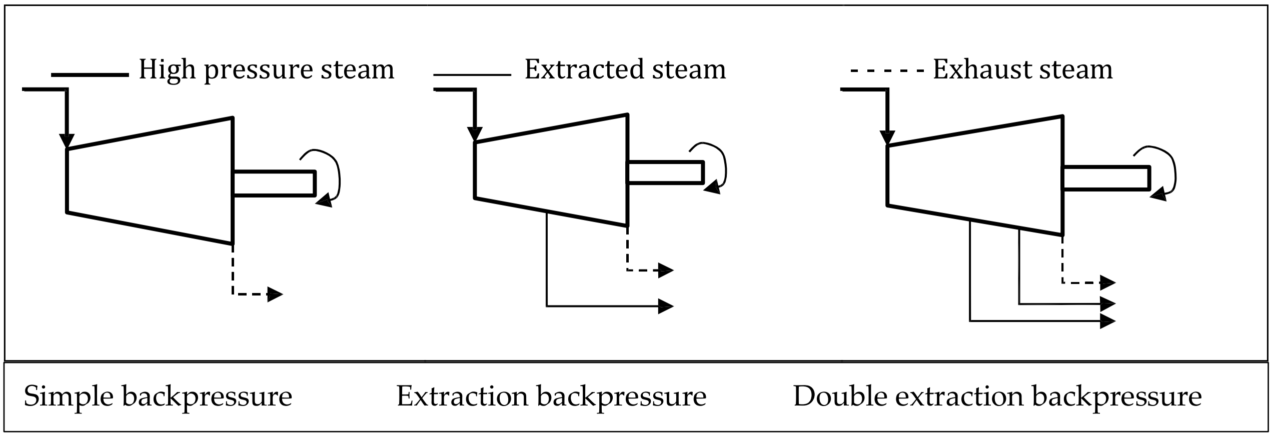


Figure 7.6: Configurations for back pressure steam turbines

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 Figure7.6 shows a two stage extraction cum condensing turbine. In this medium pressure (MP) steam and low pressure (LP) steam is extracted 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.

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 overall 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 is 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 leaves 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.

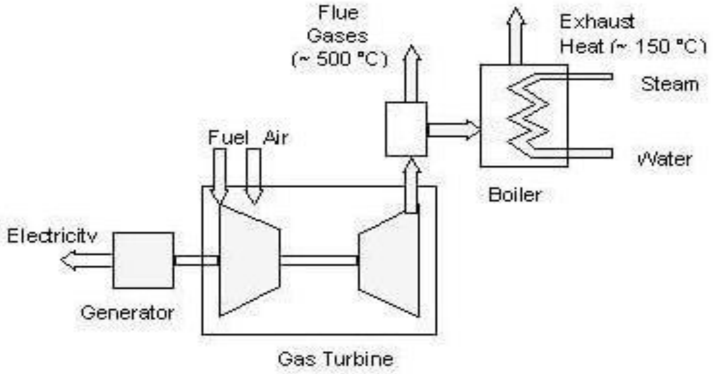


Figure 7.7: Gas turbine

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 do 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 useful power output (in MWh expressed in Btu/hr) and useful thermal output (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

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 Cogeneration Package	**Nominal Range (Electrical), kW**	**Electrical Generation to Heat Rate, kCal/kWh**	**Efficiencies, %**		
			Electrical Conversion	Thermal Recovery	Overall Cogeneration
Smaller Reciprocating Engines	10 – 500	2650–6300	20-32	50	74-82
Larger Reciprocating Engines	500 – 3000	2400–3275	26-36	50	76-86
Diesel Engines	10-3000	2770–3775	23-38	50	73-88
Smaller Gas Turbines	800-10000	2770-3525	24-31	50	74-81
Larger Gas Turbines	10-20	2770-3275	26-31	50	78-81
Steam Turbines	10-100	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 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	2.0-10.0	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
Pharmaceutical	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.

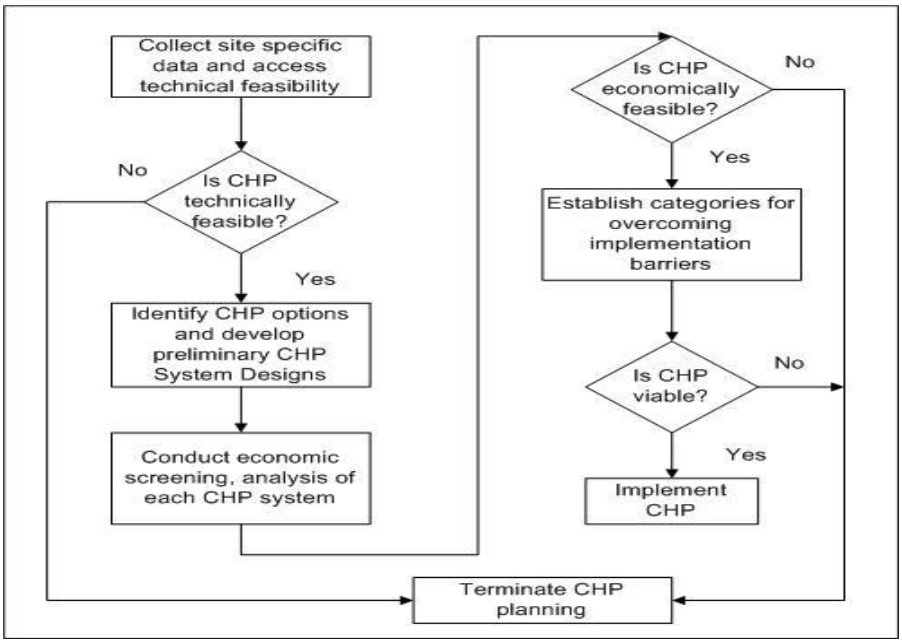


Figure 7.8: Framework for evaluating CHP viability

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, PKR/kW	400 -2000	800 -3700	2600 - 5000	1800 - 3000	1800 - 3000
Maintenance cost, PKR/kWh	≤ 0.004	0.006 - 0.02	≤ 0.036	0.01 - 0.03	0.014 - 0.04
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 hours	40000 - 80000 hours	15 - 25 years	15 - 25 years
Part-load operation	Good	Poor	Satisfactory	Good	Satisfactory

Prime Mover Characteristic	**Steam Turbine**	**Gas turbine**	**Micro turbine**	**Reciprocating Engine**	
NOx control options	Unnecessary but may be required as part of steam supply system	Steam or water injection, lean premix combustion, SCR, SNCR and SCONOXIM	Lean premixed combustion, SCR, SNCR and SCONOXIM	Lean air-fuel mixture, SCR, SNCR and SCONOXIM	Lean air-fuel mixture, staged ignition, catalytic 3 way combustion (TCW), SNCR and SCONOXIM
Preferred use of recovered heat	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 load operation	Base load, load tracking and peak shaving operations	Base load, load tracking and peak shaving operations	Base load, load tracking, emergency and peak shaving operations	Base load, load tracking, emergency and peak shaving operations
Potential applications	Topping cycle, bottoming cycle, combined cycle and trigeneration CHP system	Topping cycle, combined cycle and trigeneration CHP system	Topping cycle, combined cycle and trigeneration CHP system	Topping cycle, combined cycle and trigeneration CHP system	Topping cycle, combined cycle and trigeneration CHP system

a. Based on CHP systems that operate at least 8000 hours per year
b. Total CHP efficiency is a measure of total output(net electricity generated + net heat supplied to the process) divided by total heat 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				
Co-generator rate structure, Standby charges, Reliability		X							
Requirements, Payment									

Required Information	Sources of Information								
for Power to Grid									
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 construction cost due to complicated foundations
Gas turbine with waste heat recovery boiler	• Good fuel efficiency • Simple plant • Low civil construction 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 construction cost due to block foundations & least number 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/ Sm3	9500
Price of gas	PKR/Sm3	15.13
Capital investment for Cogeneration plant	Million PKR	130
Cost Estimation of Power & Steam from Cogeneration Plant		
Power generated = PLF x Plant Capacity x Operating hrs	Million kWh/ Year	28.8
Heat input = Power generated x Heat rate given by turbine supplier	Million kCal	87833.376
Natural gas(NG) required per annum = Heat input/ LCV of NG	Million Sm3	9.245
Annual cost of fuel = Gas consumed x price	Million PKR	139.886
Annualized Cost of capital and operation charges	Million PKR	149.678
Overall cost of power from cogeneration plant (Alternative -I Cost)	Million PKR	289.564
Cost of power	PKR/kWh	10.05

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	PKR/kWh	12
Capital investment for 10TPH, 8.5 kg/cm2 @ 200°C NG fired fire tube boiler & all auxiliaries	Million PKR	80.0
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 288 million kWh (Assuming PKR 12/kWh)	PKR/ year	345.6
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	Million kCal/ year	54115.2

Alternative-II Electric Power from State Grid & Steam from Natural Gas (NG) Fired Boiler		
Heat input required to generate 10TPH steam per annum @ 90% efficiency	Million kCal/ year	60128.0
Natural gas(NG) required per annum = Heat input/ LCV of NG	Million Sm3/ year	6.329
Annual cost of fuel = Gas consumed x price	Million PKR	95.76
Total cost for alternative II= Cost of grid power + fuel cost for steam	**Million PKR**	**441.36**
Alternative - I total cost	**Million PKR**	**289.57**
Alternative - II total cost	**Million PKR**	**441.36**
Differential cost	**Million PKR**	**151.79**

(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.

Chapter 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 loss arises 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 equipment 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	400°F – 1100°F	80°F – 400°F
(593°C – 1649°C)	(204°C – 593°C)	(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	Pre-heat combustion air	Generate power	Generate Process steam	Pre-heat boiler water	Heat process liquids	Corrosive and viscous fluids	Heating and ventilation
Heat Exchanger							
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 Recuperator

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 Recuperator

Stack type recuperator 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 are 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 requires substantial heat difference between exhaust gas and preheat air.

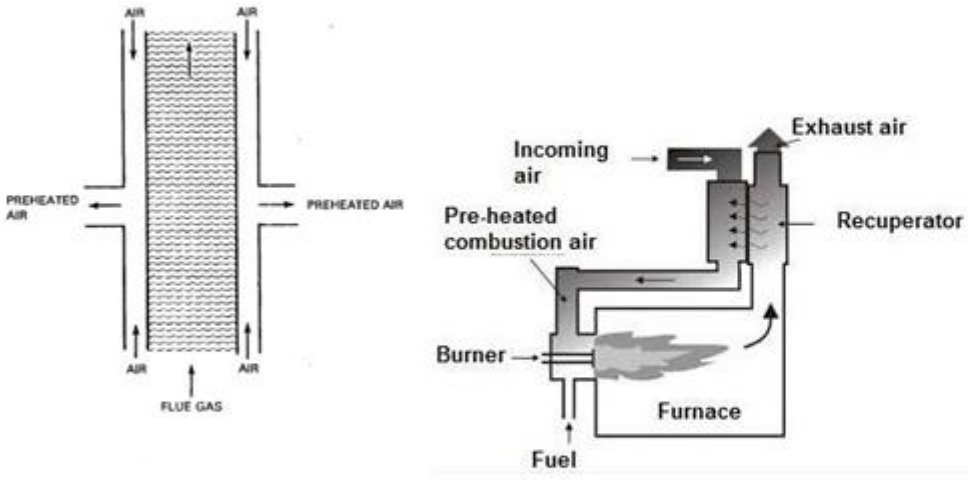


Figure 8.1: Preheating Combustion Air using a Recuperator in Furnace

Direct contact recuperator (ceramic and metal) heat exchangers

Direct contact recuperator 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.

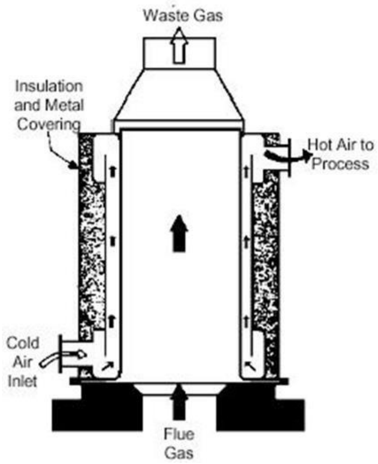


Figure 8.2: Metallic radiation recuperator

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.

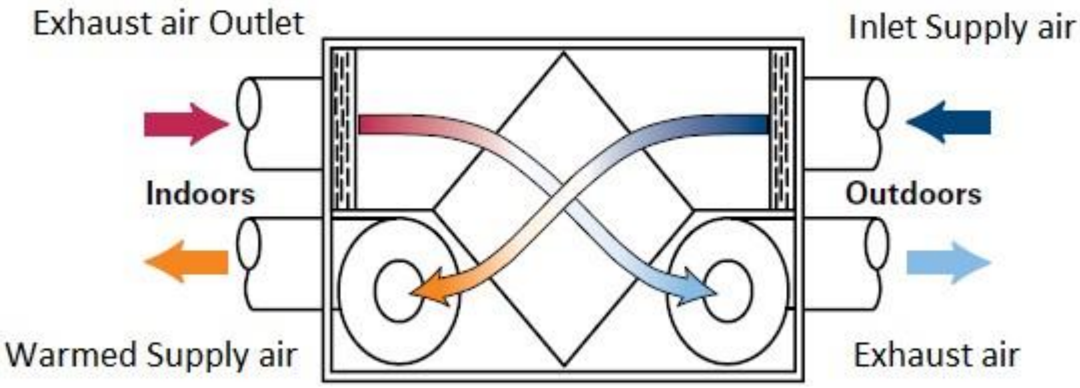


Figure 8.3: Flat Plate Recuperator

8.4.1.3 Plate fin (ceramic and metal) heat exchangers

Plate fin heat exchangers overcomes the problems associated with direct contact types and for high temperature applications (> 1360°F discharge air and > 1500 °F for flue gas) are available in both metal and ceramic designs.

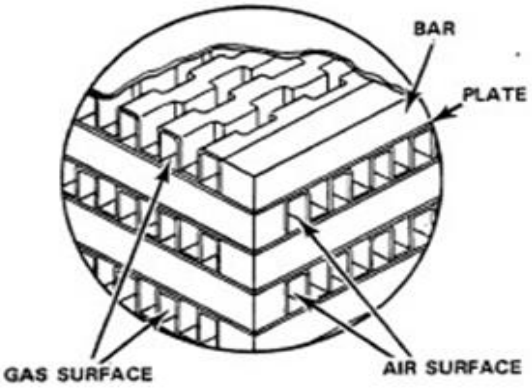


Figure 8.4: Plate Fin Heat Exchanger

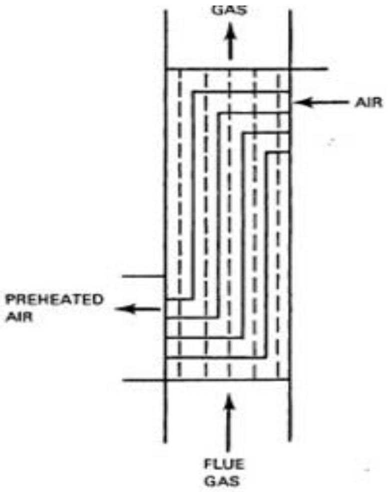


Figure 8.5: Metallic Recuperator with cross-counter flow design

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.

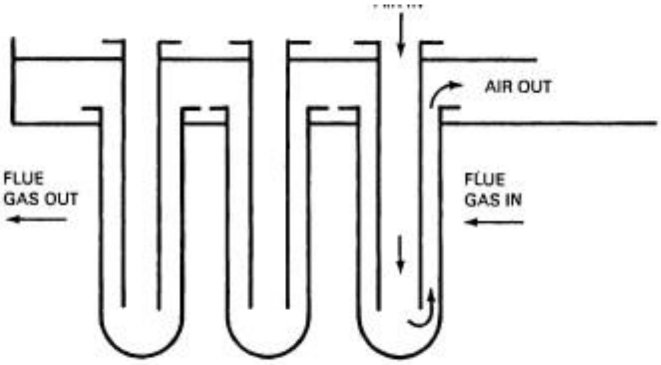


Figure 8.6: Ceramic Re-entrant Tube Heat Exchanger

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.

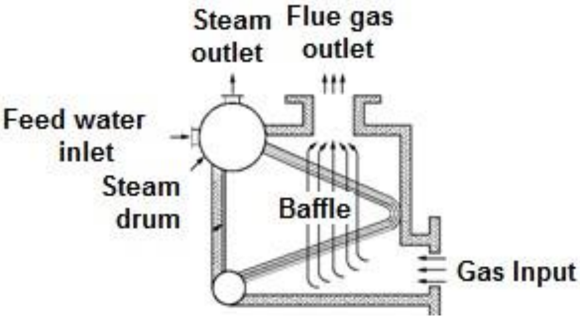


Figure 8.7: Generating Steam using Waste Heat Boiler

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. captures the latent heat (~1000 BTU/lb of water vapor contained) as well as the remaining sensible heat.

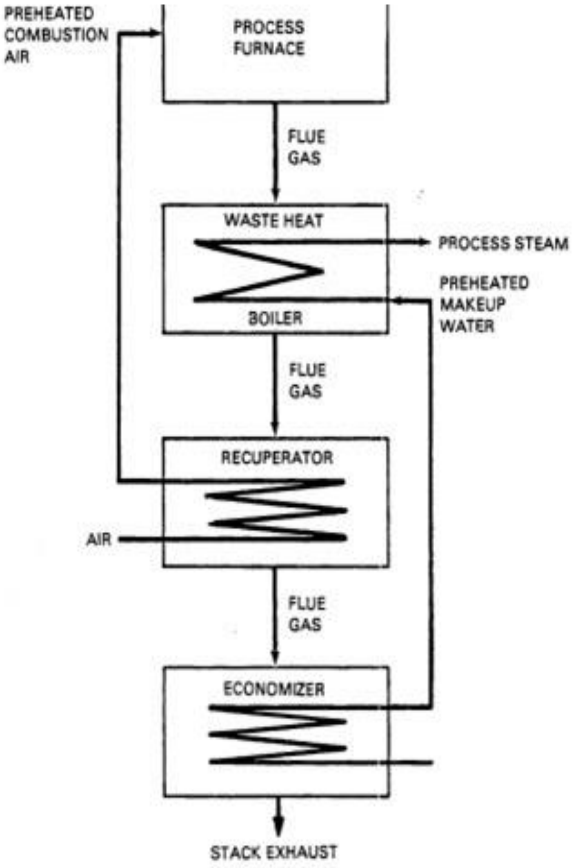


Figure 8.8: Schematic Diagram of Waste Heat Boiler Recuperator and Economiser

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- heptace, 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 vaporizer by a liquid pump.

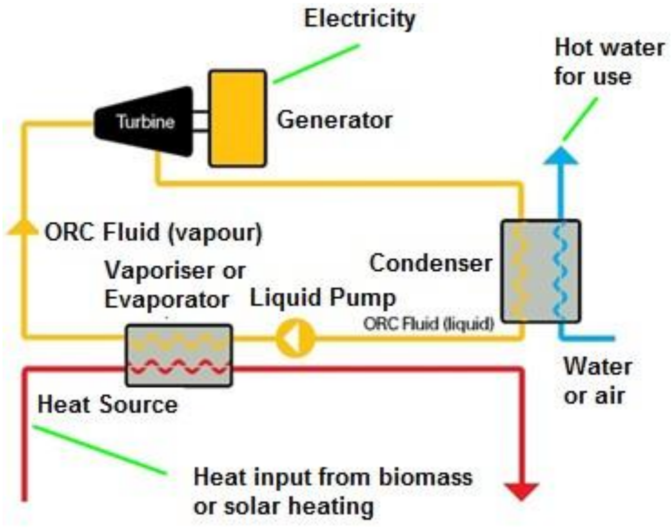


Figure 8.9: Schematic of a Small Scale Organic Rankine Cycle

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 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 tubes. 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 tis 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 (refer Figure 8.11), also called compact heat exchangers (have surface areas greater than 650m2/m3), 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 heat transfer surface area. Ports located at the corners of individual plate separates '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 same 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 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 pharmaceutics. 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

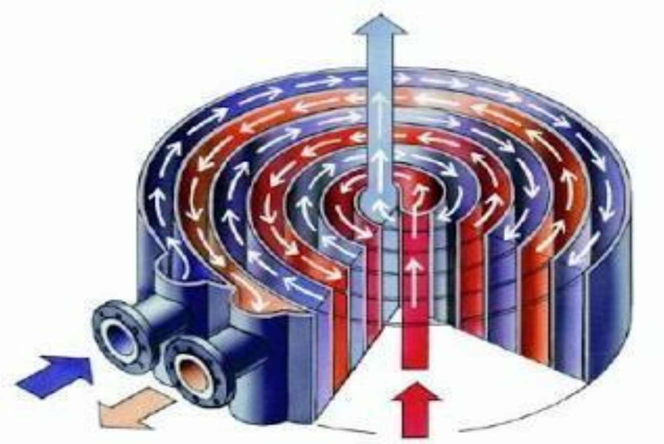


Figure 8.12: Spiral Heat Exchanger

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.

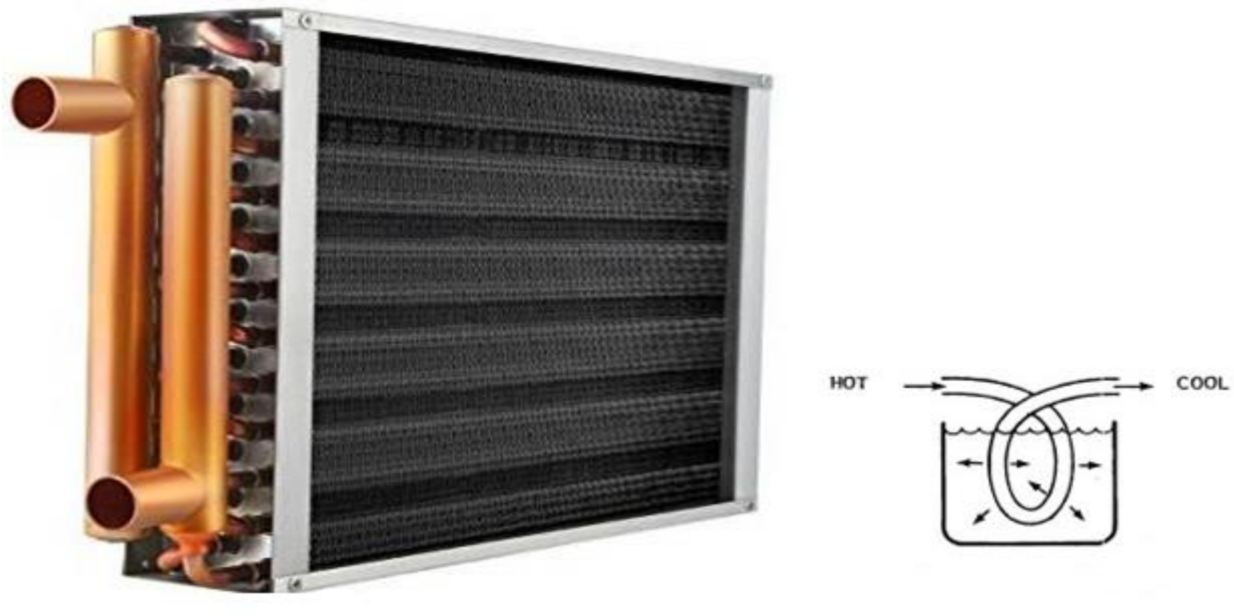


Figure 8.13: Coil Heat Exchanger

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 utilize standard air/water heating coils.

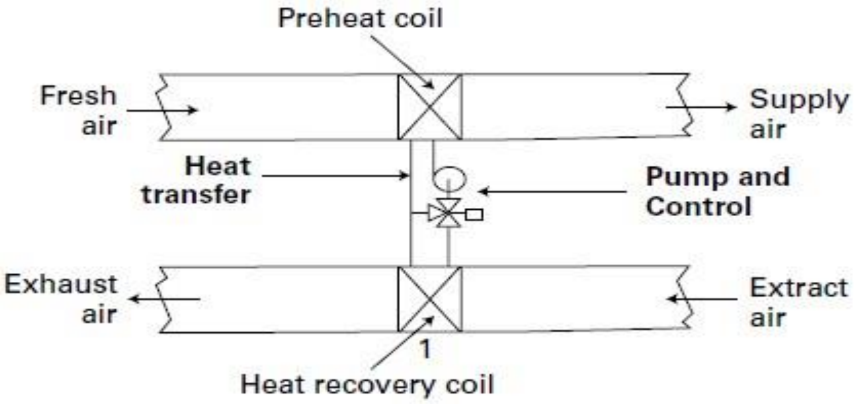


Figure 8.14: Run-around Coil Heat Recovery System

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 common 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.

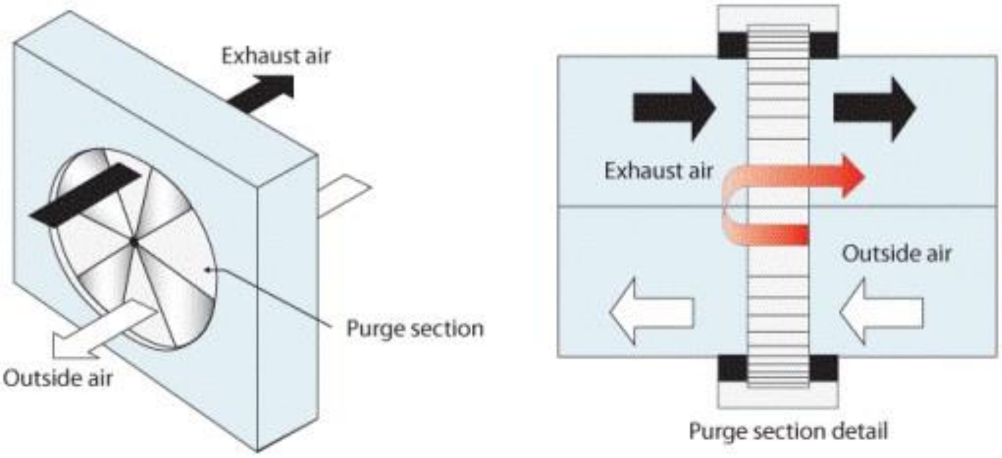


Figure 8.15: Thermal Wheel

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 vaporization 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.

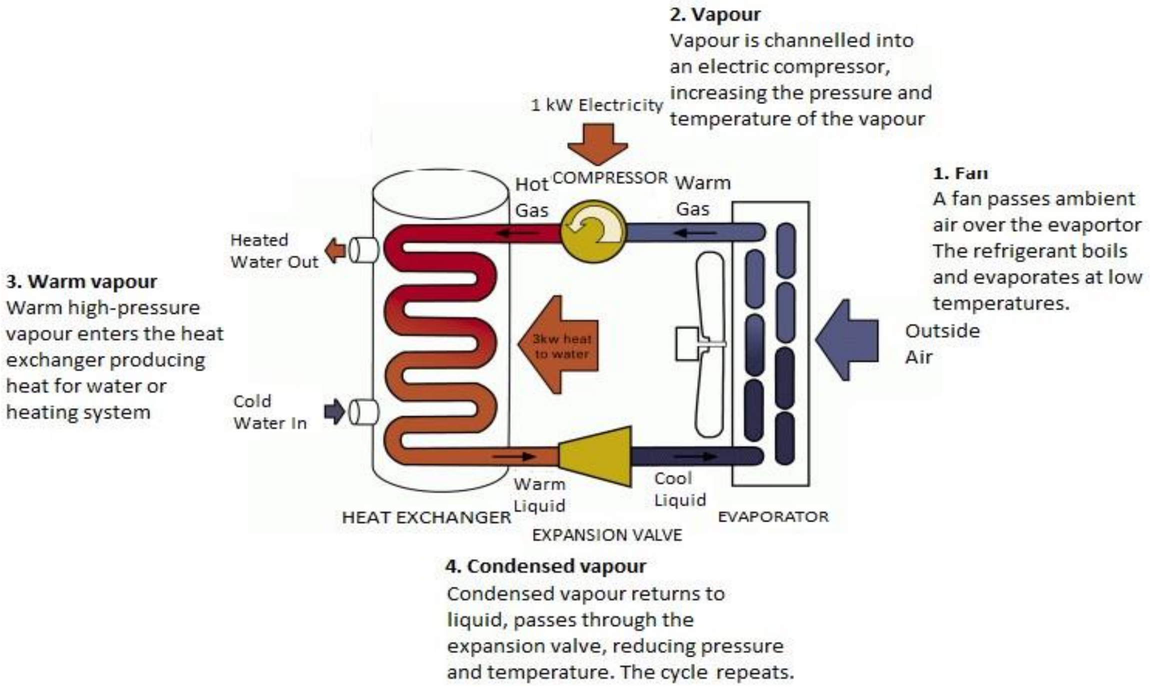
The main disadvantage of thermal wheels is that there is the possibility of cross-contamination between the air streams. This can be reduced considerably by ensuring that the cleaner of the two fluids is maintained at the highest pressure and with a use of purging device.

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.


2. Vapour
Vapour is channelled into an electric compressor, increasing the pressure and temperature of the vapour

1. Fan
A fan passes ambient air over the evaportor The refrigerant boils and evaporates at low temperatures.

3. Warm vapour
Warm high-pressure vapour enters the heat exchanger producing heat for water or heating system

4. Condensed vapour
Condensed vapour returns to liquid, passes through the expansion valve, reducing pressure and temperature. The cycle repeats.

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 refrigeration machine:

$$COP_{Rf} = \frac{Useful\ refrigeration\ output}{Net\ work\ input}$$

For heat pump:

$$COP_{Hp} = \frac{Useful\ heat\ rejected\ cycle}{Net\ work\ Input}$$

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) 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.

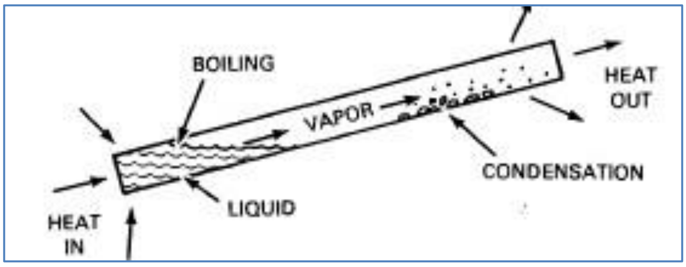


Figure 8.17: Heat Pipe

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 becomes 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-cools the building makeup air in summer and thus reduces the total tons of refrigeration, apart from the operational saving of the cooling system. Thermal energy is recovered from the cool exhaust and transferred to the hot supply make up air.

Advantages of heat pipe system

- Heat pipes operate 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 m^3/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 PKR 112,000.

Solution:

Savings in Hospital Cooling Systems

Parameters	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)	PKR/Million kCal (based on 0.8KW/TR)	268
Plant capacity reduction cost (Capital)	PKR/TR	12,000
Capital cost savings	PKR	1,12,000/-
Payback period	hours	16570

8.5.5 Thermo-compressor

In many cases, very low pressure steam is 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.

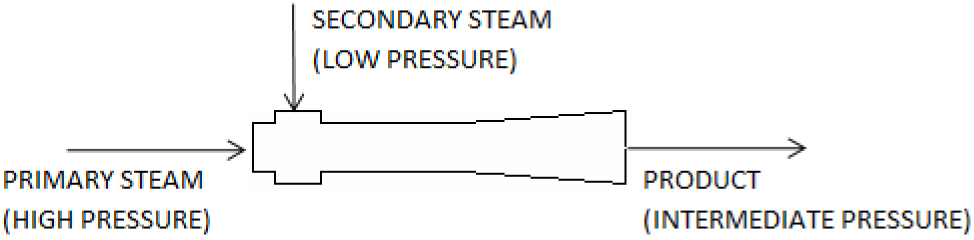


Figure 8.18: Thermo-compressor

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
Cost of Thermo-compressor	PKR 0.15 Million
Savings of jacket steam due to recompression of vapour	PKR 0.5 Million per annum
Cost of shell &tube exchanger to pre heat boiler feed water	PKR 75,000/-
Savings in fuel cost	PKR 0.45 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	650-760	CHW,CR, WHB	1,2,3,5	G-G, G-L	x	x
Zinc refining	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	925-1050	RR, CR	1	G-G	x	x
Copper	900-1100	RR, CR	1	G-G	x	x
Open hearth	650-700	CHW,CR	1,2,3,5	G-G, G-L	x	x
Cement kiln (Dry	620- 730	CHW,CR	1,2,3,5	G-G, G-L	x	x
Glass melting	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	650-1000	CHW,CR, WHB	1,2,3,5	G-G, G-L	x	x
Fume	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

1.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.

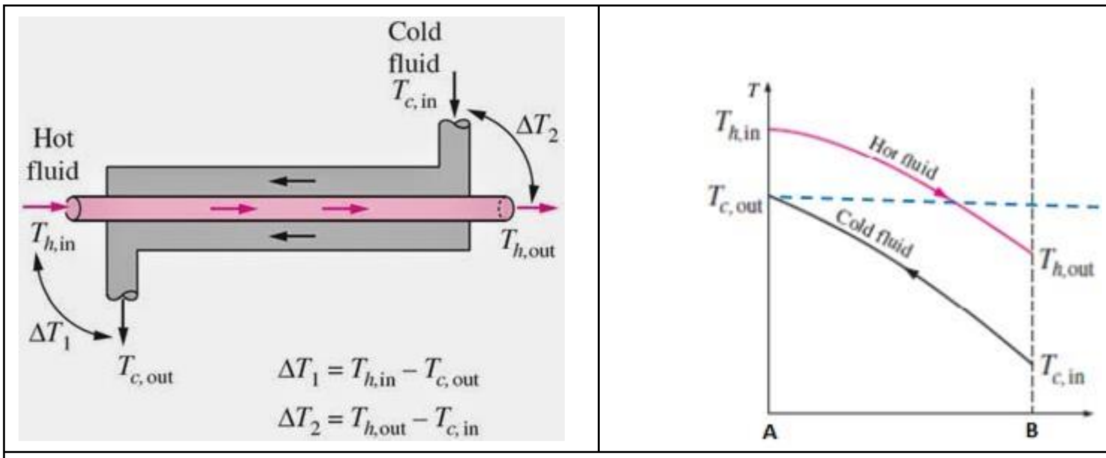


Figure 8.19: Counter Flow Heat Exchanger

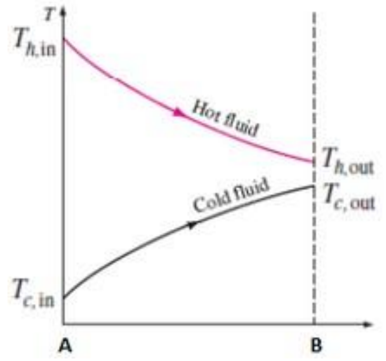


Figure 8.20: Parallel Flow Heat Exchanger

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

$$Q = UA_0(LMTD)K$$

Where,

Q : Rate of heat transfer (W)

m_h : Mass flow rate of hot fluid (kg/s)

m_c : Mass flow rate of cold fluid (kg/s)

C_h : Specific heat of hot fluid (kJ/kgK)

C_c : Specific heat of cold fluid (kJ/kgK)

t_{hin} and t_{hout} : Inlet and outlet temperature of hot fluid, K

t_{cin} and t_{cout} : Inlet and outlet temperature of cold fluid, K

U : Overall heat transfer coefficient (W/m^2K)

A_0 : Outside surface area of heat exchanger, m^2

LMTD : Logarithmic mean temperature difference

K : Constant dependent on the type of flow of heat exchanger

(k = 1 for counter flow and parallel flow and is therefore often ignored)

The logarithmic mean temperature difference can be determined by

$$LMTD = \frac{\Delta T_1 - \Delta T_2}{\ln(\Delta T_1/\Delta T_2)}$$

Where,

For counter flow heat exchanger,

ΔT_1 : $t_{hin} - t_{cout}$

ΔT_2 : $t_{hout} - t_{cin}$

For parallel flow heat exchanger,

ΔT_1 : $t_{hin} - t_{cin}$

ΔT_2 : $t_{hout} - t_{cout}$

Case Example: Heat recovery from heat treatment furnace

In a heat treatment furnace, the exhaust gases are leaving the furnace at 900^oC at the rate of 2100 m^3/hour. The total heat recoverable at 180^oC final exhaust can be calculated as

$$Q = V \times \rho \times C_p \times \Delta T$$

Q : heat content in kCal

V : flow rate of the substance in m^3/hr

ρ : density of the flue gas in kg/m^3

C_p : specific heat of the substance in kCal/kg °C

ΔT : 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.

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Book 3:
Energy Efficiency in Electrical Utilities

Guide Book

For

National Certification Examination for

Energy Auditors and Managers

National Energy Efficiency and Conservation Authority

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One of the main tasks of the project was the finalization of syllabus, and course modules including the development of model question banks for examination processes. This task was entrusted to a consortium of experts from two organizations, namely The Energy and Resources Institute (TERI) India, and PITCO from Pakistan.

This Book covers details of electrical systems, electric motors, air compressors, refrigeration and air conditioning systems, fans and blowers, pumps and pumping systems, cooling towers, lighting system and energy conservation building codes.

The members of consortium would like to express their gratitude to:

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Their comments and feedback helped the consultants to make sure that the recommendations made were the most appropriate and fair in terms of benefits to the project developers, the government and other relevant partners.

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Chapter 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. Figure1.1 shows a simple electric supply system with transmission and distribution network and linkages from electricity sources to end- user.

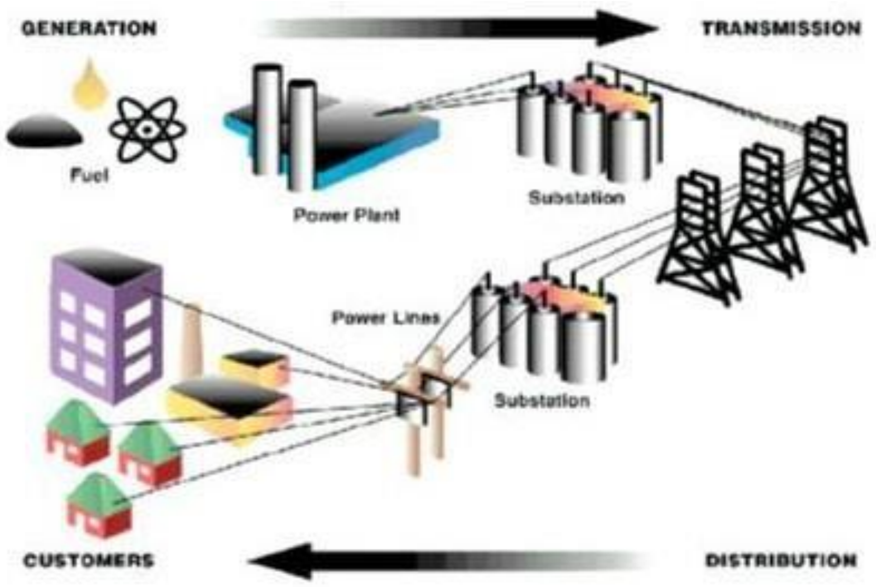


Figure 1.1: Electric supply system

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 67.98% of gross power generation in 2017-18 in Pakistan is from thermal power plants, of which 44% is from Natural gas and 32.9% from Furnace Oil based power plant.

The Installed capacity of Power Generation (by fuel type) as on June, 2018 is given below:

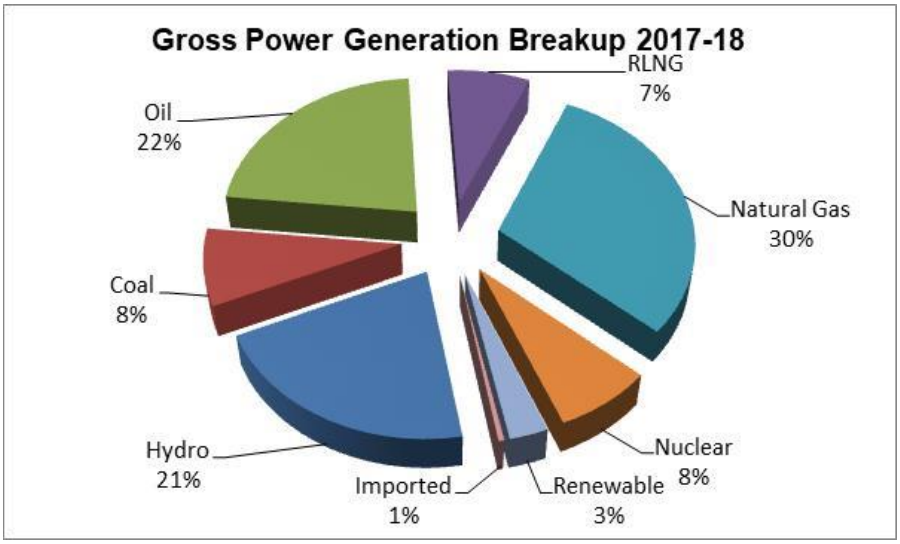


Figure 1.2 Gross Power Generation Breakup of Pakistan in 2017-18

In 2017-18, Pakistan had a peak demand of 26,741MW. The National Electricity and Power Regulatory Authority (NEPRA) has drawn an indicative expansion plan which projects that by 2040, Pakistan will have a peak demand of 65,042MW at a 4.5% GDP growth rate and a peak demand of 110,736MW at a 7% GDP growth rate.

Transmission and distribution lines

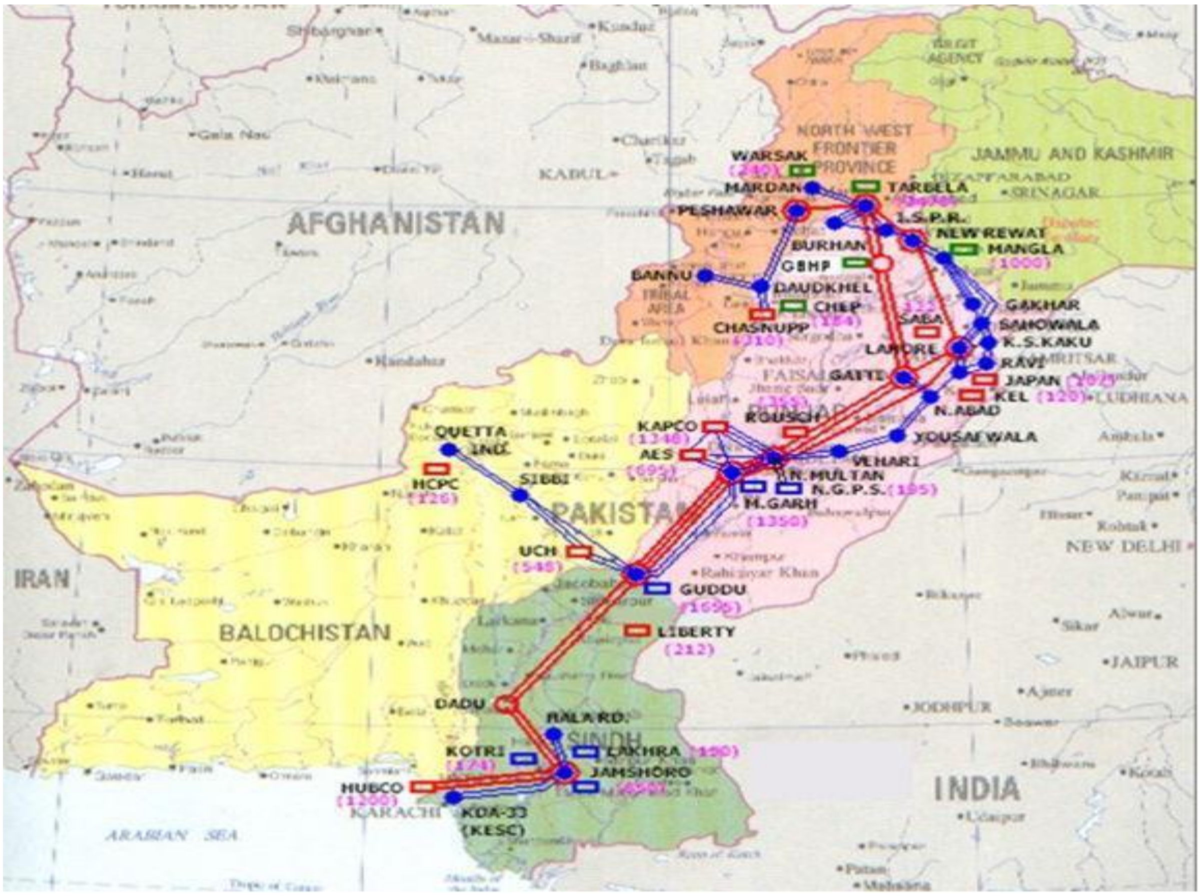
As per Grid Code of Pakistan, allowable range for frequency variation is 49.8 to 50.2 Hz. Power plants typically produce 50 cycle/second (Hertz) alternating-current (AC) electricity with Terminal voltage of 11 KV. The transmission and distribution network include sub-stations, lines and distribution 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 employed to carry the lower current and to reduce losses. Sub-stations, containing stepdown 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 cannot be stored virtually in the system there 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; 500kV, 220 kV, 132 kV and 66kV. Primary Transmission lines with 500 kV connects north to south, and transmission lines with 220 kV, 132 kV and 66 kV branched from 500 kV are connected to main market called secondary transmission lines. Where transmission is over 1000km, high voltage direct current transmission (HVDC) is also favored to minimize the losses.

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 is the current drawn and higher will be 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. $P_{Loss}=I^2R$). 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.



Pakistan Primary Grid System
Map not to scale
Source: Electricity Infrastructure in Pakistan, an overview

Cascade Efficiency

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 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, age of plant and capacity utilization.

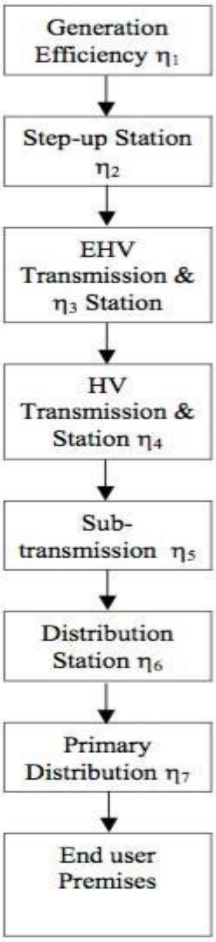
- Step-up to 500 kV to enable EHV transmission. Envisaged maximum losses 1.0% or efficiency of 99%
- EHV transmission and substations at 500 kV. Envisaged maximum losses 1.0% or efficiency of 99%
- HV transmission & Substations for 132/220kV. Envisaged maximum losses 2.5% or efficiency of 97.5%

- Sub-transmission at 66/132 kV. Envisaged maximum losses 4% or efficiency of 96%
- Step-down to a level of 11/33kV.Envisaged losses 0.5% or efficiency of 99.5%
- Distribution is final link to end user at 11/33kV. Envisaged losses maximum 5% or efficiency of 95%

Cascade efficiency from Generation to end user =

$$\eta 1 \times \eta 2 \times \eta 3 \times \eta 4 \times \eta 5 \times \eta 6 \times \eta 7$$

The cascade efficiency in the T&D system from output of the power plant to the end use is 87% (i.e. 0.995 x 0.99 x 0.975 x 0.96 x 0.995 x 0.95=87%)



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 Figure 1.3.

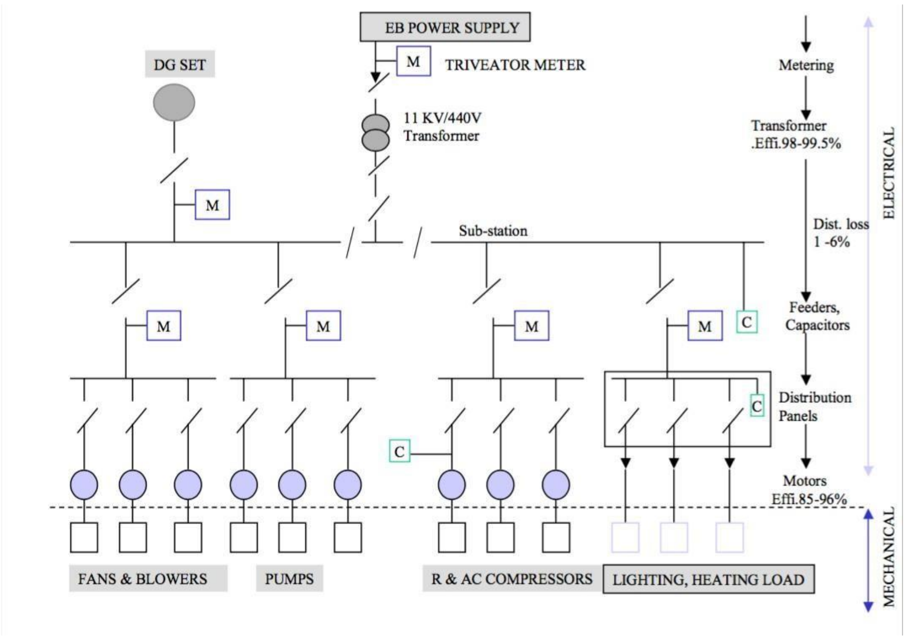


Figure 1.3: Electrical Distribution System – Single Line Diagram

The likely network elements that are encountered at industry–up to the motor, i.e. pre-motor system can include.

- Outdoor circuit breakers with typical full load losses percentage of 0.002 – 0.015%
- Receiving transformers with typical operating efficiency of 99% or above.
- Medium voltage switch gear 6.6 kV 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 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 from0.01%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. Overall T&D (Transmission and Distribution) loss in Pakistan is around 17%. All these may not constitute technical losses, since un-metered and pilferage are also accounted in this.

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%. Another30% (Efficiency=65%) 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%. (0.90x0.95x0.9x0.65= 0.50, i.e. 50% efficiency)

Hence, one unit saved in the end user is equivalent to two units generated in the power plant. (1Unit/0.5Eff=2 Units)

1.2 Electricity billing

The electricity billing by utilities for medium & large industries and enterprises (Category B3/B4) 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. 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, 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) *Interruptible and adjustable rates* like 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 m is 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 (in case MD is measured in kW):

$$\frac{(2500\text{x}4) + (3600 \text{ x } 12) + (4100 \text{ x } 6) + (3800 \text{ x } 8)}{30} = 3606.7\text{kW}$$

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 is 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 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 a way 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.

$V = I \times R$ 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)

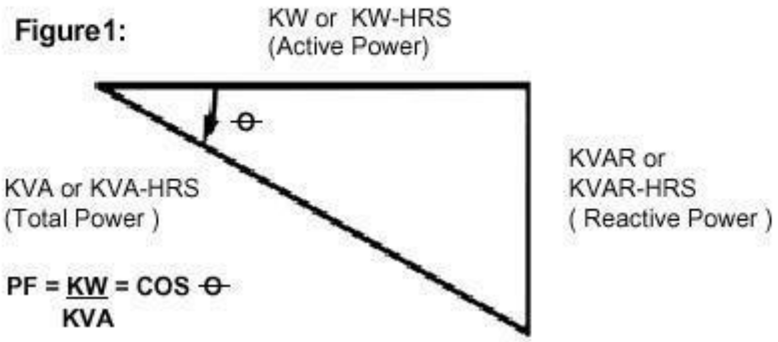


Figure 1.4: Power factor

The active power (shaft power required or true power required) in kW and the reactive power required (kVAr) are 90^0 apart vectorially 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 a1500KVA 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 the1500KVA 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.

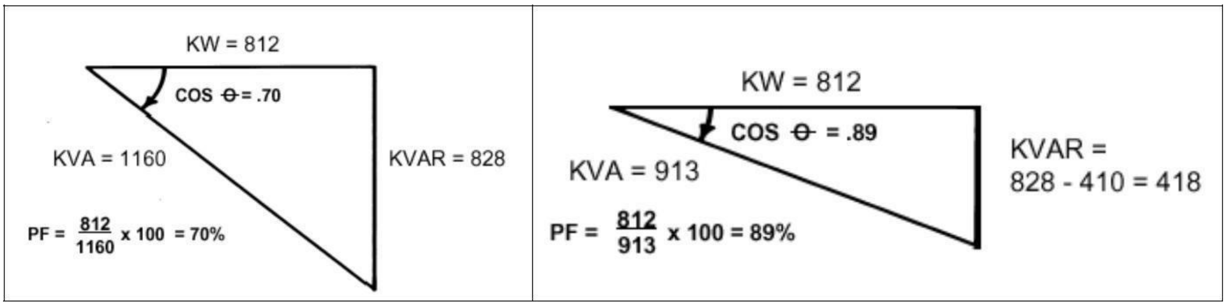


Figure 1.5: Power factor before and after Improvement

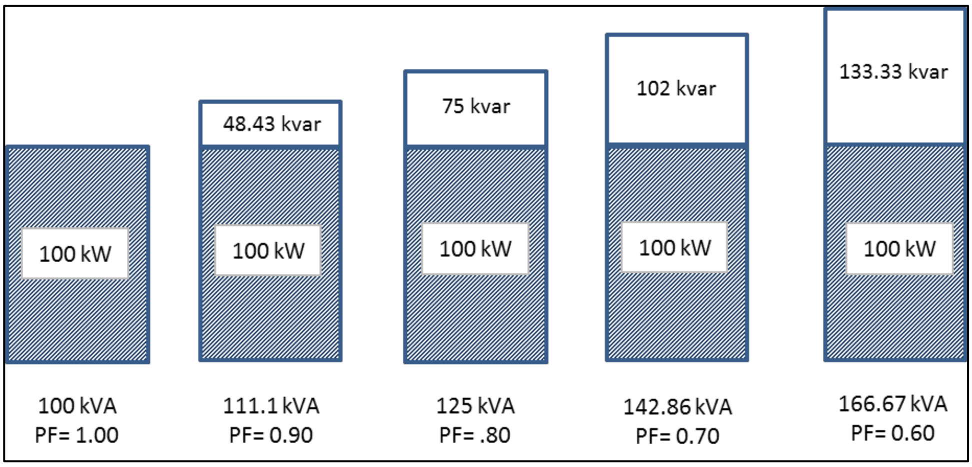


Figure 1.6: Increase in the apparent and reactive powers as a function of the load power factor, holding the real power of the load constant

The advantages of improvement by capacitor addition

a) Reactive component of the network is reduced and also the total current in the system from the source end.
b) I^2R power losses are reduced in the system because of reduction in current.
c) Voltage level at the load end is increased.
d) 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:

a) Reduced KVA (Maximum demand) charges in utility bill
b) Reduced distribution losses (KWH) within the plant network
c) Better voltage at motor terminals and improved performance of motors
d) A high power factor eliminates penalty charges imposed when operating with a low power factor
e) 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	0.76
0.60	1.333	1.004	0.849	0.714	0.58
0.65	1.169	0.840	0.685	0.549	0.41
0.70	1.020	0.691	0.536	0.400	0.27
0.75	0.882	0.553	0.398	0.262	0.13
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

$$\text{KVAr Rating} = \text{KW} [\text{Tan } \varphi 1 - \tan\varphi 2]$$

where, KVAr rating is the size of the capacitor needed, KW is the average power drawn, tan φ1is the trigonometric ratio for the present power factor, and tanφ2 is the trigonometric ratio for the desired PF.

$$\varphi_1 = \text{Existing } (\text{Cos}^{-1}\, \text{PF}_1) \text{ and } \varphi_2 = \text{Improved } (\text{Cos}^{-1}\text{PF}_2)$$

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 within the plant's 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 $[1 - (PF_1 / PF_2)^2]$

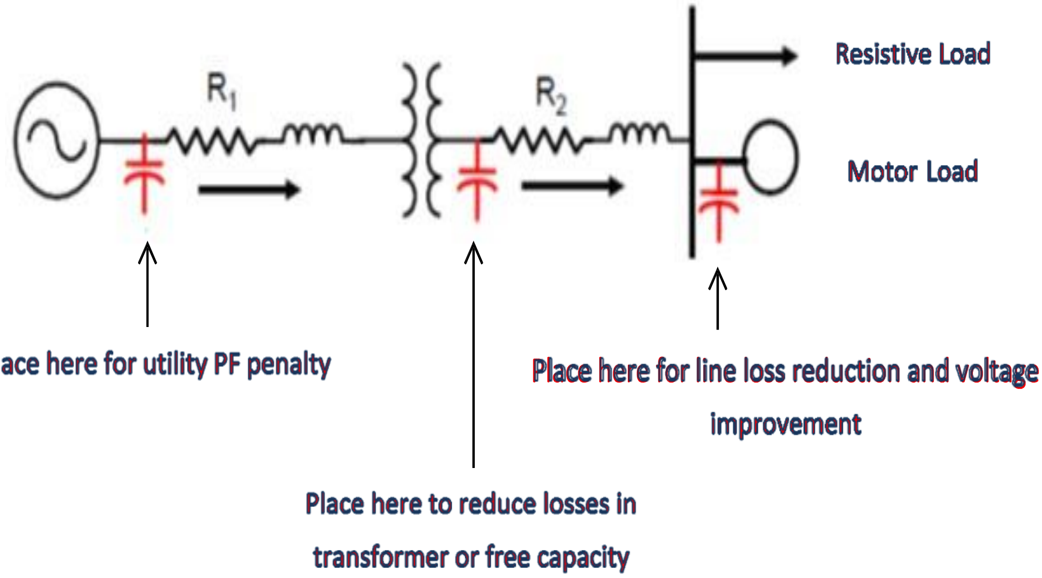


Figure 1.7: Effect of capacitor location on other loads

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.

Welding Transformer Rating kVA	Capacitor Rating kVAR
Single Phase	4
12	6
18	8
24	1
30	1 8
Three Phase	
57	16.5
95	30
128	45

160	60

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. The recommended capacitor ratings for various sizes of welding transformers are given in table below.

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 $V1^2/V2^2$, where V1 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.

Table 1.2: Effect of addition of kVAR capacitor

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 lagging
90	274	89	70	73	0.95 (1.05) leading
105	276	95	70	79	0.89 (1.11)

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:

i. Name plates can be misleading with respect to ratings. It is good to check by charging currents.

ii. 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 with 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 supply 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. (500 kV, 220 kV, 132kV, 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 is 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.($P=I^2R$).

For a given transformer, the manufacturer can supply values for no-load loss, $P_{NO\text{-}LOAD}$, and load loss, P_{LOAD}. The total transformer loss, P_{TOTAL}, at any load level can then be calculated from:

$$P_{TOTAL} = P_{NO\text{-}LOAD} + (\%\ \text{Load}/100)^2 \, x P_{LOAD}$$

Where transformer loading is known, the actual transformers loss at given load can be computed as:

$$No\ load\ loss + \left(\frac{KVA\ Load}{Rated\ KVA}\right)^2 full\ load\ loss$$

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	11000/433	425	3000	5
200		570	3300	5
250		620	3700	5
315		800	4600	5
500		1100	6500	5
630		1200	7500	5
1000		1800	11000	5
1600		2400	15500	5
2000		3000	20000	6
630	33000/433	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 minimize 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.

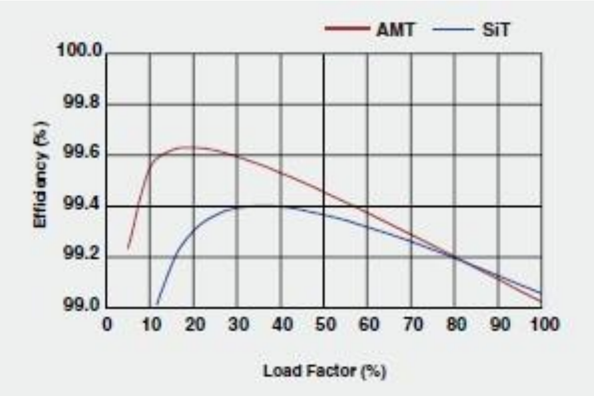


Figure 1.8: Comparison of Conventional and Amorphous Core Transformers

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 x 2.8 =5.6
Load Loss = 2 x (750/1000)^2 x 11.88 = 13.36
Total Loss = 5.6 + 13.36 =18.96

b) Total loss when Three transformers in parallel operation:
No load loss = 3 x 2.8 = 8.4KW
Load loss = 3 x (500/1000)^2 x 11.88 = 8.91 kW
Total loss = 17.31 kW

Savings by operating 3 transformers in parallel
= 18.96-17.31= 1.65 kWh
= 1.65kwh x 24Hrs x 365 days = 14454 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 network 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.

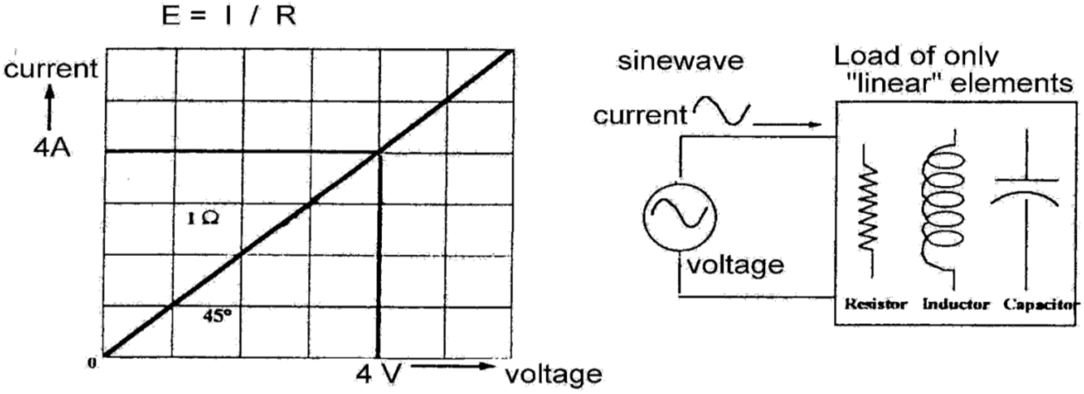


Figure 1.9: Linear loads

However in real life situation, various devices like 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.

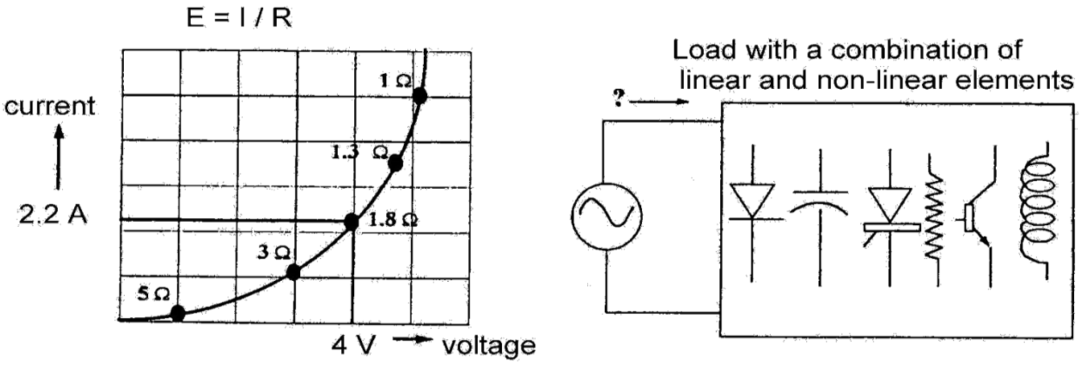


Figure 1.11: Non-Linear loads

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

$$\%THD = \sqrt{\sum_{n=2}^{n=n} \frac{V_n{}^2}{V_1}} * 100$$

where V_1 is the fundamental frequency voltage and V_n is nth harmonic voltage component.

In terms of current it is expressed as below

A5th harmonic current is simply a current flow in gat 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:

$$= \sqrt{\frac{(I_5^2 + I_7^2)}{I_1}}$$

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 I7 = 35Amps

Then...

$$I_{THD} = \sqrt{\frac{(50^2 + 35^2)}{250}} \quad x\ 100 = 24\%$$

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 voltages 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 analyzers cans through 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 liked diodes and thyristors which area 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	3,5,7,9,11,13…
Fluorescent Lights	3,5,7,9,11,13…
Arcing Devices	2,3,4,5,7…
Transformer	2,3,4

Generally, the magnitude decreases as harmonic order increases.

$$H = NP+/-1$$

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 consisting 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 harmonics related 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 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 (Isc / IL) 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 IL

	Individual Harmonic Order (Odd Harmonics)					
Isc/IL	**<11**	**11 ≤ h < 17**	**17 ≤ h < 23**	**23 ≤ h < 35**	**35 ≤ 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 Isc/IL.						
Where, Isc = Maximum short circuit current at PCC. And IL = 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**
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)
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 x 1/4 = 0.5 kWh.
Power	√3 × V × I × PF for 3 phase systems, where V = Line voltage, I = line current • In delta connected electrical system, V line = V phase, I lines = √3 I phase • In star connected electrical system, V line = √3 V phase, I lines = I phase and V × I x PF for single phase systems
	√3 × V × I for 3 phase systems and V x I for single-phase systems.
	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 loader 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

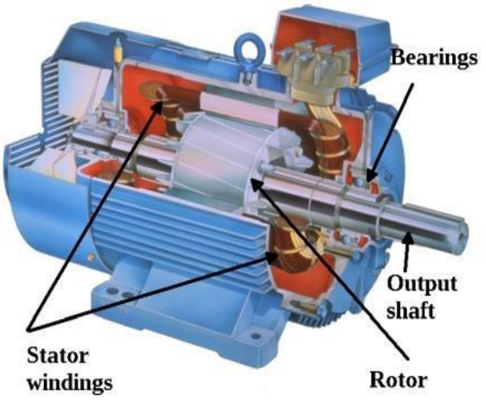
System Problem	Common Causes	Possible Effects	Solutions
Voltage imbalances among the three phases	Improper transformer tap settings, single-phase loads not balanced among phases, poor connections, bad conductors, transformer grounds or faults.	Motor vibration, premature motor failure A 5% imbalance causes 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.

Chapter 2 Electrical Motors

2.0 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.

2.1 Motor Types

2.1.1 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).

In induction motors, the induced magnetic field of the stat or 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.

2.1.2 Direct-Current Motors

Direct-Current motors, as then am 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.

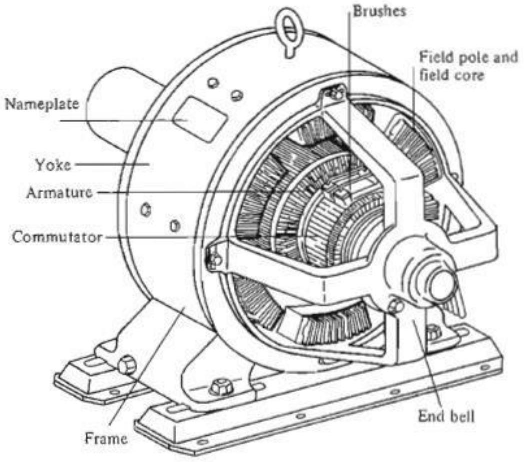


Figure 2.1: DC Motor

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

2.1.3 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.

2.2 Motor Characteristics

2.2.1 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 input power and number of poles for which the motor is wound. The synchronous speed in RPM is given by the following equation, where frequency is in hertz or cycles per second:

$$\text{Synchronous Speed (RPM)} = \frac{120 * Frequency}{No.of\ Poles}$$

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:

$$\text{Slip (\%)} = \frac{Synchronous\ Speed - Full\ Load\ Speed}{Synchronous\ Speed} * 100$$

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.

2.2.2 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 2πfl. At low frequencies, this impedance approaches zero making the circuit appear to be a short circuit.

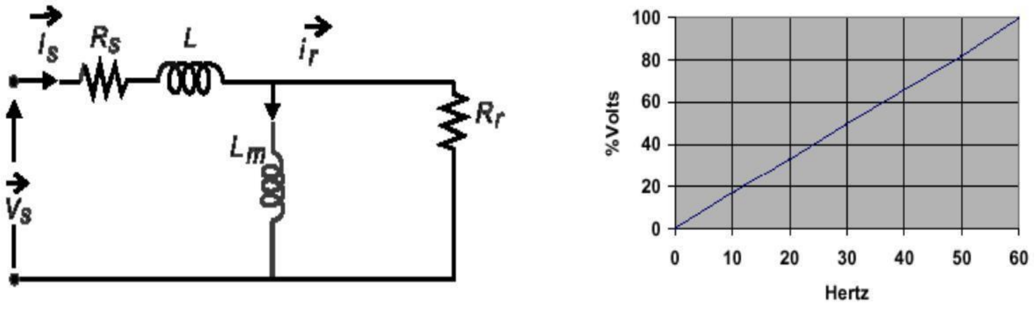


Figure 2.2: Volts/Hz Relationship

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.

2.2.3 Power Factor

The power factor of the motor is given as:

Power Factor = Cos φ = 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.

2.2.4 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.

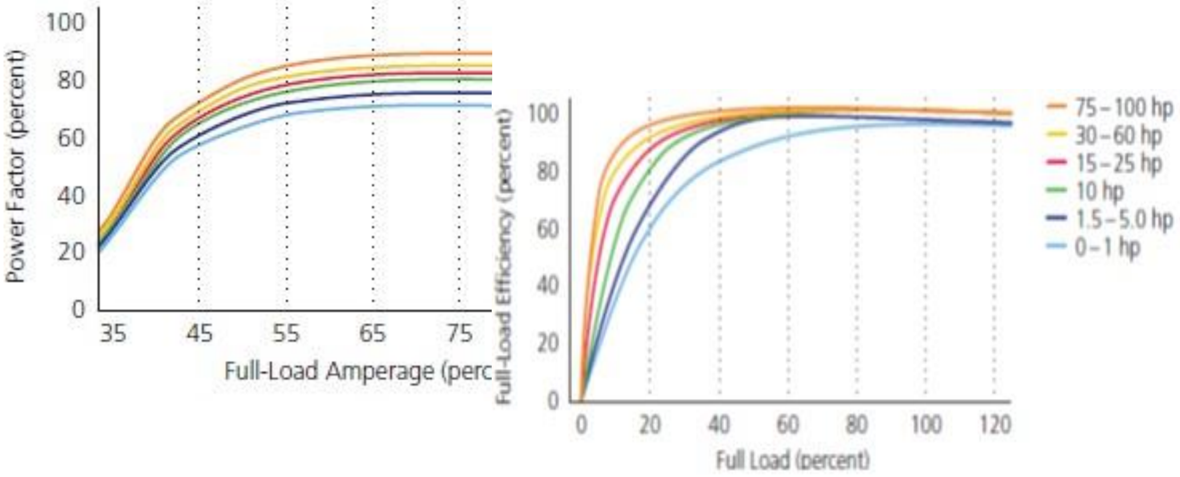


Figure 2.3: Power factor at different loads

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 wind age 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 wind age 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 results in heat generation, that is proportional to resistance of the material and 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.

2.3 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 a result 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 re placed, 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 standard- efficiency motor.

2.3.1 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 of100^0C to 120^0C and necessary correction should be made. Correction to 75^0C 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 taco meter. 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^{0}C	0.264 Ohms
No load power, P_{nl}	1063.74Watts

a) Calculate iron plus friction and windage losses

b) Calculate stator resistance at 120^{0}C

$$R_2 = R_1 * \frac{235 + \ t_2}{235t_1}$$

c) Calculate stator copper losses at operating temperature of resistance at 120^{0}C

d) Calculate full load slip (s) and rotor input assuming rotor losses are slip times rot or input.

e) Determinethemotorinputassumingthatstraylossesare0.5%ofthemotorrated power

Calculate motor full load efficiency and full load power factor

Solution

a) Iron plus friction and windage loss, Pnl = 1063.74 Watts

Stator Copper loss, Pst-30^{0}C =3×(16.2/$\sqrt{3}$)^2 ×0.264 = 68.43 Watts

Pi+fw=Pnl –Pst

Cu loss = 1063.74 – 68.43 = 995.3

b) Stator Resistance at 120^{0}C,

R120^{0}C = 0.264 × ((120 + 235)/ (30+235)) = 0.354 ohms

c) Stator copper losses at full load,

Pst Cu loss@120^0C =3 × $(57/\sqrt{3})$ ^2 ×0.354 = 1150.1Watts

d) Full load slip S = (1500 – 1475) / 1500 = 0.0167

Rotor input, Pr = P output / (1-S) = 34000 / (1-0.0167) = 34577.4 Watts

e) Motor full load input power, P input =Pr +Pst

Cu loss @120°C+Pi +fw+Ps tray = 34577.4 + 1150.1 + 995.3 + (0.005 × 34000)

=36892.8 Watts

f) Motor efficiency at full load Efficiency

= P_{out}/P_{input} ×100 = 34000/36892.8 ×100 = 92.2%

Full Load PF = P_{input} / √3 × V × I = 36892.8 / 3 × 415 × 7 = 0.9

Comments:

a) The measurement of stray load losses is very difficult and not practical even on test beds.

b) 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.

c) The value of full loads lip taken from the name plate data is not accurate. Actual measurement under full load conditions will give better results.

d) The friction and wind age 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.

e) 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.

2.4 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

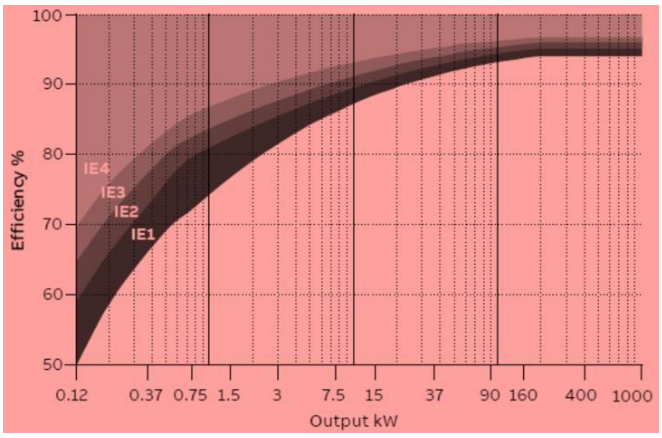


Figure 2.4: IE efficiency classes for 4 pole motors at 50 Hz

(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 drop 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:

2.4.1 Stator and Rotor I2R 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.

2.4.2 Core Losses

Core losses are those found in the stator-rotor magnetic steel and are due to hysteresis effect and eddy current effect during 50Hz 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 be 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.

2.4.3 Friction and Wind age 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%of total losses. 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.

2.4.4 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 energy efficient motors can be achieved only by careful selection, implementation, operation and maintenance efforts of energy managers.

	Energy Efficient
Power Loss	**Efficiency**
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^2R	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^2R	Use of larger rotor conductor bars increases size of cross section,
4. Friction &	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.

2.5 Factors affecting Energy Efficiency & Minimising Motor Losses in operation

2.5.1 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. The general effects of voltage and frequency variation on motor performance are presented in following figure 2.5:

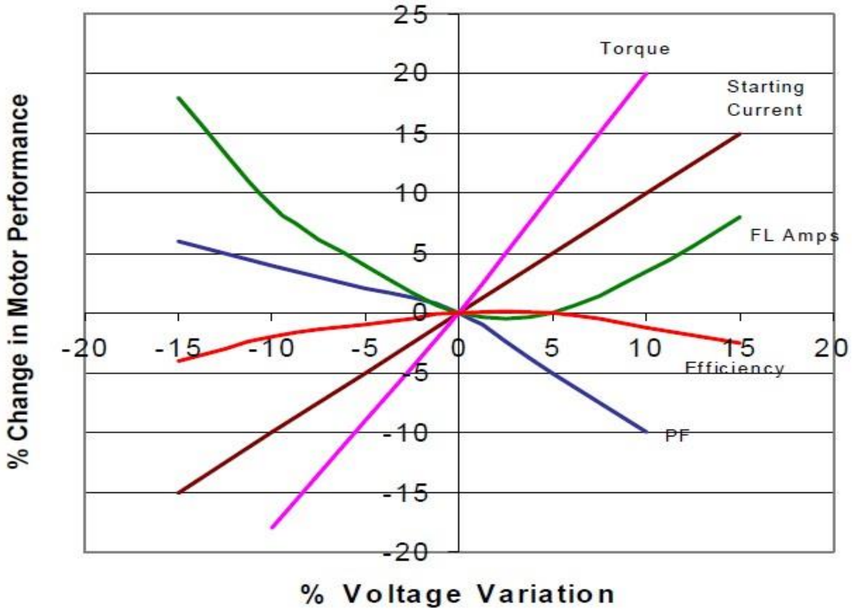


Figure 2.5: **Effect of Voltage Variation on Induction Motors**

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	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 4-6°C	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 4-8°C	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

Particulars	**Percent unbalance in voltage***		
	0.30	**2.30**	**5.40**
Unbalance in current (%)	0.4	17.7	40.0
Increased temperature rise(^{0}C)	0	30	40

Percent unbalance in voltage is defined as 100 x ($V_{max} - V_{avg}$) / V_{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:

$$\textbf{Voltage unbalance} = \frac{\textbf{Maximum deviation from mean of } V_{ab}, V_{bc}, V_{ca}}{\textbf{Mean of } (V_{ab}, V_{bc}, V_{ca})}$$

For example, if the line voltages are Vab = 410, Vbc = 417, and Vca = 408

% Voltage unbalance = (417 – 411.7/ 411.667) x 100 = 1.29%

Where,
Mean = (410 + 417 + 408)/3 = 411.7V
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;

- 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

$$\text{Additional temperature rise} = 2 \text{ x } (\% \text{ Voltage unbalance})^2$$

For example, if the voltage unbalance is 2% for a motor operating at 100^{o}C, the additional temperature rise will be 80°C. The winding insulation life is reduced by one half for each 10^{0}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.

2.5.2 Motor Loading - 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 stator 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. However, a simple method for working out the Motor loading is used by energy auditors, is given below:

$$\%\,Loading = \frac{Input\ power\ drawn\,by\,the\,motor\ (kW)\ at\,existing\ load}{Name\,plate\ full\,load\ kW\ rating\,/\,name\,plate\ full\,load\ motor\ efficiency} x100$$

or

$$\% Loading = \frac{Input\ power\ drawn by the motor\ (kW)\ at existing\ load}{\sqrt{3}\ x\ kV\ x\ I\ x\ Cos\phi}\ x\ 100$$

- Never assume power factor
- Loading should not be estimated as the ratio of currents.

$$Motor\ Loading\ \% = \frac{Actual\ operating\ load\ of\ the\ motor}{Rated\ capacity\ of\ the\ motor}\ x\ 100$$

Another Alternative method used for assessing motor loading is :

Load = (Slip/ Ss - Sr)*100%

Where:
Load = Output power as a % of rated power
Slip = Synchronous speed - Measured speed in rpm
Ss = Synchronous speed in rpm at the operating frequency
Sr = Nameplate full-load speed
Slip also varies inversely with respect to the motor terminal voltage squared.

A voltage correction factor can, also, be inserted into the slip load equation. The voltage compensated load can be calculated as shown

$$Load = \frac{Slip}{(S_s - S_r)\ x\ (V_r / V)^2}\ x\ 100\%$$

Where:
Load = Output power as a % of rated power
Slip = Synchronous speed - Measured speed in rpm
Ss = Synchronous speed in rpm
Sr = Name plate full-load speed
V = RMS voltage, mean line to line of 3phases
Vr = Nameplate rated voltage

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 lathe 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, there 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 in expensive 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 '√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.

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.

2.5.3 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					
	300	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

Motor Rating (HP)	Capacitor rating (kVAR) for Motor Speed					
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. Major factor to be considered while analyzing the installation of capacitor is "operating hours" of motor.

2.5.4 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 10^0C 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. In adequate 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.

2.5.5 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.

2.5.6 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		Motor No Load Current				Starter Resistance/ phase		No load loss	
			Sq. Cage	Slip Ring	New		Rewound		New	Rewound	New	Rewound
					A	V	A	V			Watts	Watts

2.5.7 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 a synchronous motor, the speed of which can be varied by changing the supply frequency. The speed can be also be varied through a number 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 enquired varies with the speed of operation. Centrifugal pump sand 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 a typical 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- upon 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.

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 in frequent 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 off our 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	Advantages	Disadvantages
ELECTRO-MECHANICAL CONTROLMETHODS		
Variable Pulley	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 4Fixed 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; steeples 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 is used to transmit the energy to the load.

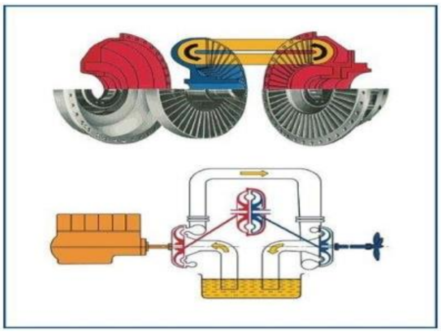


Figure 2.6: Fluid Coupling Construction

Fluid couplings work on the hydrodynamic principle. It consists of a pump-generally known 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 intelligent VFD for the three phase induction motor is shown in Figure 2.7.

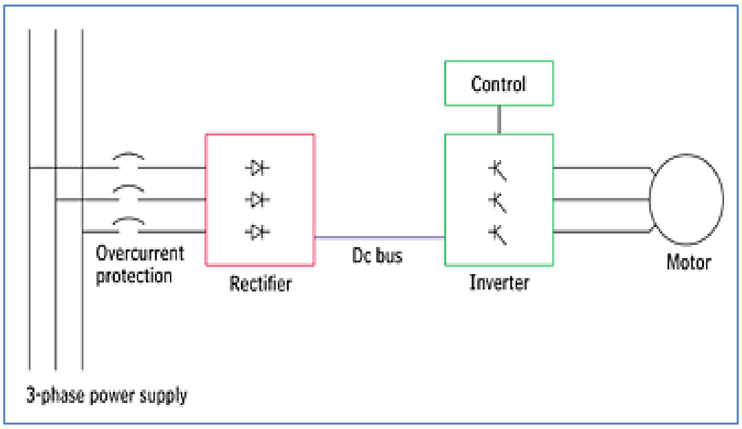


Figure: 2.7 Components of a Variable Speed Drive

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.

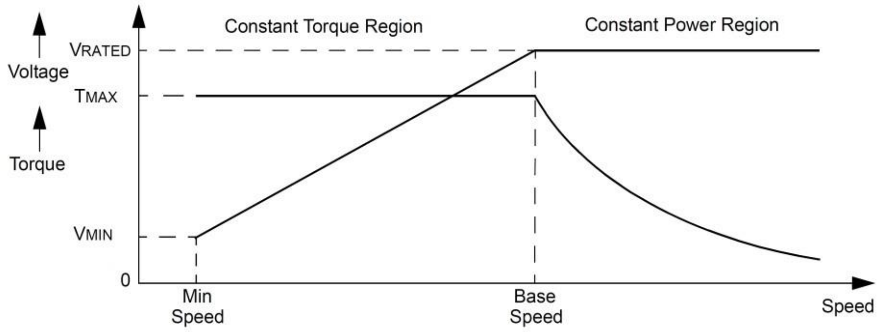


Figure 2.8: V/f Control

As seen in Figure 2.8, 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

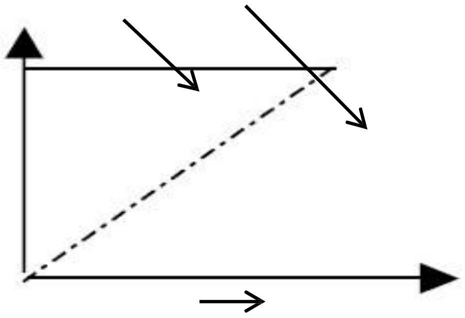
The size of the VFD depends mainly on driven load type and characteristics. This will determine the drive capacity in terms of full load current (FLC) and power delivered (kW).

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.

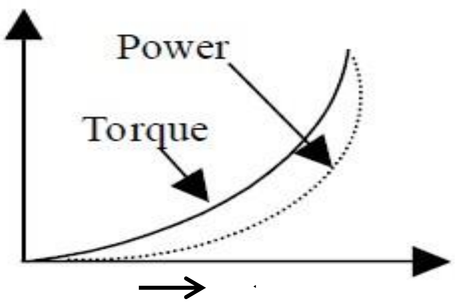
A CT load implies that the load torque seen at motor shaft is independent of motor speed. This means that the load torque remains approximately the same at all speeds. Examples of CT loads include material handling conveyers, reciprocating & screw compressors and certain types of blowers such as roots 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.



Motor Shaft Speed (RPM)

Figure 2.9 A CT load characteristic



Motor Shaft Speed (RPM)

Figure 2.10 A VT load characteristic

Variable Frequency Drives: Precautions

- **Ensure that the power voltage** supplied to VFDs is stable within plus or minus10% 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 40^{0}C (104^{0}F), 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 disconnect.
- **If a motor always operates at rated load**, a VFD will increase power use, due to electrical losses in the VFD.

2.5.8 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 inverters with only a few pulses per second as compared to more complex ones that produce a12-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. The non-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 harmful. Low level distortions may still be present, but these do not pose a serious problem.

2.5.9 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.

2.5.10 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 to flat belt drive is 5 to 6% and from Worm gearbox to Helical Gearbox 8 to 10%

2.5.11 Soft Starters

A soft starter is another form of reduced voltage starter for A.C. induction motors which facilitates 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, contactors and 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 economic 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
- 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 equipment, unloading type air compressors, punch presses, center less grinding and polishing machines, blowers, wherever the motor load is varying continuously.

2.5.12 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 one 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 10 fans, with 142kW consumption among five sets of supply air & return air fans, the savings achieved were 377223kWh worth PKR.37.7 lakhs/year against an investment of PKR 25lakhs @ PKR 2.5 lakh/ 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
Rp	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 derating 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 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 machines 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.

Chapter 3 Compressed Air Systems

3.1 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 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.

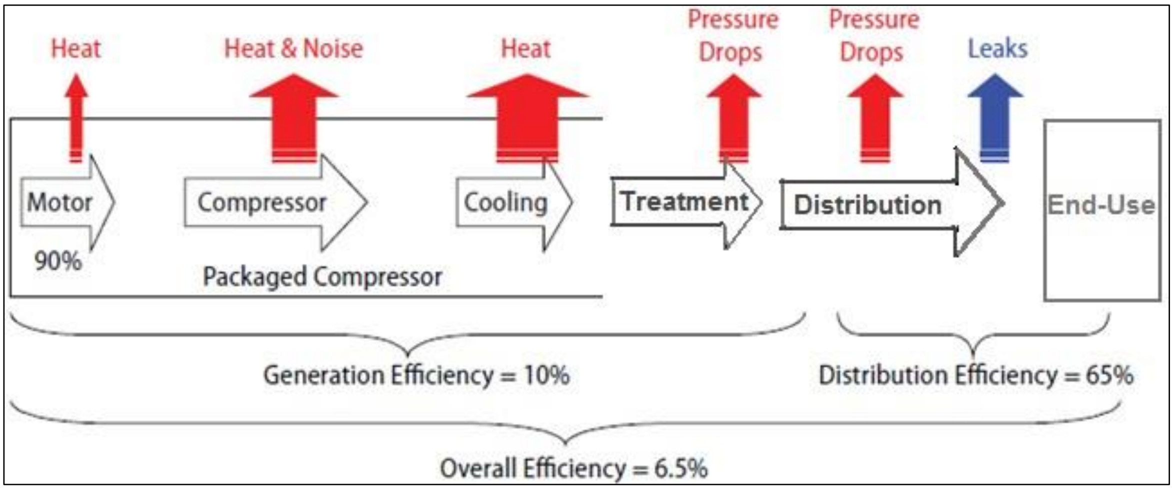


Figure 3.1: Efficiency of Compressed Air System

3.2 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 particulars type of compressor.

3.3 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 arrange 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. Vertically reciprocating compressors are used in the capacity range of 50–150cfm. 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.

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 – 160^0C) compared to single-stage machines (205 – 240^0C). 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 1barin 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 type with single or twin screw compressors, deliver oil-free air and are available in sizes up to 20,000cfm and pressure up to 15 bar, and in the size range of 100 – 1000cfm in lubricated designs up to 10 bar discharge pressure.

They cannot operate at discharge pressures below 3.5bar. In the case of oil injected (lubricated) rotary screw compressor, oil has to be separated from the discharged air (gas).

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 up to 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.

3.4 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 better suited for applications requiring very high capacities, typically above 12,000cfm. 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	100	30000	0.1	1
Reciprocating				
- Single / Two stage	100	12000	0.8	12
- Multi stage screw	100	12000	12.0	700
- 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- 5%)	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.

3.5 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 bents or refrigerant dryers, or state of the art heat of compression 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.

3.6 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 a diabetic or isothermal or mechanical efficiency. These are computed as the isothermal and a diabetic power respectively, divided by the actual power consumption. The calculation of isothermal power excludes that needed to overcome friction and generally gives an efficiency that is lower than a diabetic 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 in take would be slightly higher because of mechanical losses.

For practical purposes, the 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.

$$Theoretical\ kW = \left(\frac{NK}{K-1}\right)\left(Q\,\frac{P_s}{0.612}\right)[\left(\frac{P_d}{P_s}\right)^{\frac{K-1}{NK}} - 1]$$

N = No. of stages
K = Ratio of specific heats (1.35 for air)
Ps = suction pressure in kg/cm2
P_d = Discharge pressure in kg/cm^2
Q = Actual air flow (m^3/min.)
Actual kW = √ 3 V I × PF as measured

Efficiency of compressor and motor combination = $\frac{100 \times \text{Theoretical kW}}{Actual\ kW}$

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

$$Volumetric\ efficiency = \frac{Free\ air\ delivered\ (\frac{m3}{min})}{Compressor\ Displacement\ (\frac{m3}{\min})} x100$$

$$Compressor\ Displacement = \frac{\pi}{4} D^2 \times L \times S \times \chi \times n$$

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

3.7 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 resultant 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 minimal.

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 stage 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 at each 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 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 rusting, which will result in 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 polytrophic head and polytrophic 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 is 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 advents 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 regardless 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 is 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.

3.8 Energy Efficiency Practices in Compressed Air systems

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 4^0C 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(^{0}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 (mmWC)	Increase in Power Consumption (%)
0	0
200	16
400	32
600	47
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 2 percent. 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 to 8	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	26 to10	Same as above. Recommended for rotary vane compressors in normal service

3.8.3 Dry Air Intake

Table 3.6: Moisture Levels at Various Humidity Levels

% Relative Humidity	Kg of water vapour compressed per hour for every 1000 m^3/min. of air at 30^0C
50	27.6
80	45
100	68.22

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 relative 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 a rise 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 to 25^0C 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 in 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 intake 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
50	945	98.7	97.7

Altitude Meters	Barometric Pressure	Percentage Relative Volumetric Efficiency Compared with Sea Level	
100	894	97	95.2
150	840	95.5	92.7
200	789	93.9	90
250	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, wherein 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 5^0C 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 even through the idle compressors. To avoid this waste of water supply, idle compressors should be closed or water pressures 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 throughput thus increasing cooling tower efficacy. A malfunction of fan 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 an 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 Fiber Reinforced Plastic (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 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, m
	From (mm)	To (mm)	
0.4	64	63	6
0.8	64	62	14
1.2	64	61	21
4.7	64	54	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 algaecides.

3.8.7 Efficacy of Inter and After Coolers

Inter-coolers are provided between successive stages of a 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
1st Stage inlet temperature^{0}C	21.1	21.1	21.1
2nd 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 5.5^{0}C 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 into 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 m3/min. FAD at 7 bar (lpm)
Single-stage	3.8
Two-stage	7.6
Single-stage with after-cooler	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 reducing 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 cuts-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, 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 supplying 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 100 meters	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	10	125
Gate Valve	0.11	0.14	0.18	0.27	0.32	0.40	0.49	0.64	0.91	1.20
Run of standard	0.12	0.18	0.24	0.38	0.4	0.5	0.6	0.8	1.20	1.52
Tee 900 long 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	0.7	1.0	1.3	1.8	2.4	3.20
Return bend	0.46	0.61	0.76	1.07	1.2	1.6	1.9	2.6	3.6	4.88
Through side	0.52	0.70	0.91	1.37	1.5	2.1	2.7	3.6	4.8	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 upon 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	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 than40%, 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. Table 3.17 gives the comparison of pneumatic grinders and electrical grinders.

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 areas 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 by blower systems can be replaced 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 6bar or 7bar 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 2bar. Use of compressed air amplifiers can also be considered for some cleaning applications. For applications where in 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. Vacuum systems are much more efficient than expensive venture methods, which use expensive compressed air rushing past an orifice to create a vacuum. Mechanical stirrers, conveyers, and low-pressure air 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 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 nozzles 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 (PKR/Year)
0.8	0.2	22,4000
1.6	0.8	89,6000
3.1	3.0	336,0000
6.4	12.0	1,344,000

*based on PKR 14 / kWh; 8000 operating hours; air at 7.0bar pressure

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) $\frac{(1.5) \times 35}{(1.5) + (10.5)}$

$= 4.375 CMM$

b) Leakage per day $= 6300 CM/day$

c) Specific power for compressed air generation $\frac{188 \text{ kWh}}{(35 \times 60) \text{CMH}}$

$= 0.0895 kwh/m^3$

c) Power lost due to leakages/day = 563.85kWh

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 vacated systems. Use is made of ultrasonic detector store veal air borne and structure-borne vibrations, and translators that convert these in 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 m (100feet). 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 actor to be noted is the frequency distribution of ultrasonic energy from leaks. All leaks possess energy in the30/50 kHz. At lower pressure of 480 and 70kPa (70and10psi), 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 than10%, corrective measures should be taken to rectify the same.

The ideal method of compressor capacity assessment is through a nozzle test wherein 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 (kg/cm^2 a)

P_1 = Initial pressure (kg/cm^{2}a) after bleeding

P_0 = Atmospheric Pressure (kg/cm^{2}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 cm
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/cm*^{2} a

$$Compressor\ Output, CMM = \frac{(P2 - P1) \times TotalVolume}{Atmospheric\ Pressure\ \times Pump\ Up\ Time}$$

$$= \frac{(7.03 - 0.5) \times 8.322}{1.026 \times 4.021} = 13.17 CMM$$

Capacity shortfall w.r.t. 14.75cmm rating is 1.577cmm 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	13.17	115.30	42.3	Full time*	0
B	12.32	117.20	51.8	Full time*	0
C	13.14	108.30	43.3	Full time*	0
D	12.75	104.30	29.8	Full time*	0
E	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)

i. Compressed air generated in M^3

45 x (13.17) + 45 x (12.32) + 45x(13.14) + 45x(12.75) + 5.88x(13.65) =2392.36

ii. *Power consumption kWh*

45/60 x (115.3) + 45/60x (117.20) + 45 / 60x (108.3) + 45/60x (104.3) + 5.88/60x(109.8)+ (39.12 / 60)x39.3 = 370.21kWh

iii. *Compressed air generation capacity on line in* M^3

*45 [13.17 + 12.32 + 13.14 + 12.75 + 13.65] = 2926.35*M^3

a) *The consumption rate of the section connected*

2392.36 / 45 CMM = 53.16 CMM

b) *Compressor air drawl as a % of capacity on line is [2392.36 / 2926.35] × 100 = 81.75%*

c) *Specific power consumption = 370.21 kWh / 2392.36 = 0.155*

d) *Idle power consumption due to unload operation = 25.62kWh in every 45 minutes cycle i.e., 34.16 kWh every hour.*

e) *It would be favorable and energy efficient to keep the compressor 'D' in cycling mode on account of lower un-load losses.*

f) A suitable smaller capacity compressor can be planned to replace the compressor with highest unload losses.

g) 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 1m in 100m in 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 mains 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 so on. 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 savoir 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, it gives satisfactory 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 $5dm^3/s$ 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 common types of air dryers used are heat-less (absorption), absorption and chiller dryers. They produce dry air with 10-40°C dew point, depending on the type of dryers.

Table 3.21: Moisture Content in Air

Dew point at Atmospheric Pressure, ^0C	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, °C	First Cost	Operating Cost	Power Cons. for $1000m^3$/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 high 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 minimized, 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

A simple formula 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.

$$Receiver\ capacity\ in\ m^3 = \frac{m^3\ of\ free\ air\ volume\ required}{permissible\ pressure\ drop\ in\ bar}$$

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 near 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 Utilization

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 factor which determines the type of regulation required and the type of the compressor drive.

3.8.21 Piping Layout

Wherever possible, the piping system should be arranged as a closed loop or “ring main” to allow for more uniform air distribution to consumption points and to equalize pressure in the piping. Separate services requiring heavy air consumption and at long distances from the compressor should be supplied by separate mains header. Pipes are to be installed parallel with the lines of the building with main and branch headers sloping down towards a dead end. Traps have to be installed in air lines at all low points and dead ends to remove condensate moisture. Automatic moisture traps used for this purpose are effective only when the air has been cooled and the moisture has precipitated.

Chapter 4 Refrigeration and Air Conditioning

4.1 Introduction

This section briefly describes the main features of the refrigeration and air conditioning system.

4.1.1 What is Refrigeration and Air Conditioning

Refrigeration and air conditioning is used to cool products or a building environment. The refrigeration or air conditioning system (R) transfers heat from a cooler low-energy reservoir to a warmer high-energy reservoir (see figure 4.1).

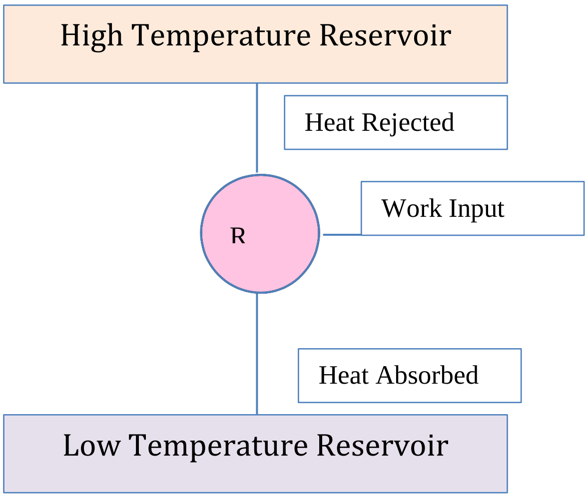


Figure 4.1. Schematic representation of refrigeration system

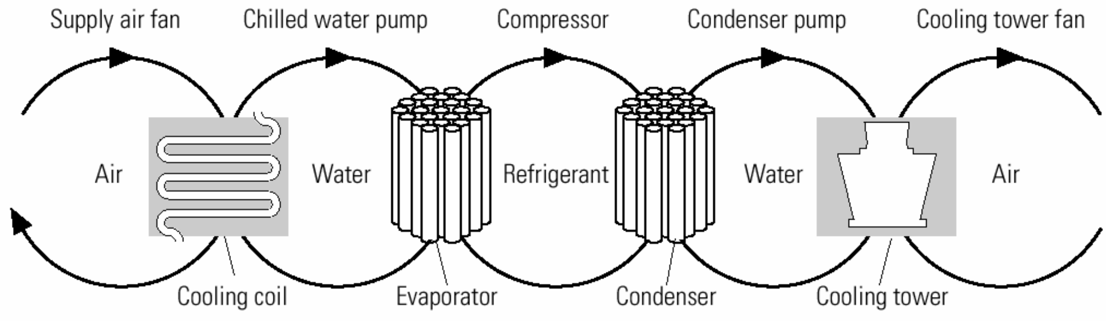


Figure 4.2. A typical Heat Transfer Loop in Refrigeration System

(Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

There are several heat transfer loops in a refrigeration system as shown in Figure 2. Thermal energy moves from left to right as it is extracted from the space and expelled into the outdoors through five loops of heat transfer:

- ***Indoor air loop***. In the left loop, indoor air is driven by the supply air fan through a cooling coil, where it transfers its heat to chilled water. The cool air then cools the building space.
- ***Chilled water loop***. Driven by the chilled water pump, water returns from the cooling coil to the chiller's evaporator to be re-cooled.
- ***Refrigerant loop***. Using a phase-change refrigerant, the chiller's compressor pumps heat from the chilled water to the condenser water.
- ***Condenser water loop***. Water absorbs heat from the chiller's condenser, and the condenser water pump sends it to the cooling tower.
- ***Cooling tower loop***. The cooling tower fan drives air across an open flow of the hot condenser water, transferring the heat to the outdoors.

4.1.2 Air-Conditioning Systems

Depending on applications, there are several options/combinations of air conditioning, which are available for use:

- Air conditioning (for space or machines)
- Split air conditioners
- Fan coil units in a larger system
- Air handling units in a larger system

4.1.3 Refrigeration Systems (for processes)

The following refrigeration systems exist for industrial processes (e.g. chilling plants) and domestic purposes (modular units, i.e. refrigerators):

- Small capacity modular units of the direct expansion type similar to domestic refrigerators.
- Centralized chilled water plants with chilled water as a secondary coolant for a temperature range over typically 5°C. They can also be used for ice bank formation.
- Brine plants, which use brines as a lower temperature, secondary coolant for typically sub-zero temperature applications, which come as modular unit capacities as well as large centralized plant capacities.

The plant capacities up to 50 TR (tons of refrigeration) are usually considered as small capacity, 50 –250 TR as medium capacity and over 250 TR as large capacity units.

A large company may have a bank of units, often with common chilled water pumps, condenser water pumps, cooling towers, as an off-site utility. The same company may also have two or three levels of refrigeration and air conditioning such as a combination of:

- Comfort air conditioning (20 –25 °C)
- Chilled water system (8^0 –10^0 C)
- Brine system (sub-zero applications)

4.2 Types of Refrigeration and Air Conditioning

This section describes the two principle types of refrigeration plants found in industry: Vapour Compression Refrigeration (VCR) and Vapour Absorption Refrigeration (VAR). VCR uses mechanical energy as the driving force for refrigeration, while VAR uses thermal energy as the driving force for refrigeration.

4.2.1 Vapour Compression Refrigeration System

Compression refrigeration cycles take advantage of the fact that highly compressed fluids at a certain temperature tend to get colder when they are allowed to expand. If the pressure change is high enough, then the compressed gas will be hotter than our source of cooling (outside air, for instance) and the expanded gas will be cooler than our desired cold temperature. In this case, fluid is used to cool a low temperature environment and reject the heat to a high temperature environment.

Vapour compression refrigeration cycles have two advantages. First, a large amount of thermal energy is required to change a liquid to a vapor, and therefore a lot of heat can be removed from the air-conditioned space. Second, the isothermal nature of the vaporization allows extraction of heat without raising the temperature of the working fluid to the temperature of whatever is being cooled. This means that the heat transfer rate remains high, because the closer the working fluid temperature approaches that of the surroundings, the lower the rate of heat transfer.

The refrigeration cycle is shown in Figure 3 and 4 and can be broken down into the following stages:

- **1 – 2.** Low-pressure liquid refrigerant in the evaporator absorbs heat from its surroundings, usually air, water or some other process liquid. During this process it changes its state from a liquid to a gas, and at the evaporator exit is slightly superheated.
- **2 – 3.** The superheated vapour enters the compressor where its pressure is raised. The temperature will also increase, because a proportion of the energy put into the compression process is transferred to the refrigerant.
- **3 –4.** The high pressure superheated gas passes from the compressor into the condenser.
- The initial part of the cooling process (3-3a) de-superheats the gas before it is then turned back into liquid (3a-3b). The cooling for this process is usually achieved by using air or water heat transfer. A further reduction in temperature happens in the pipe work and liquid receiver (3b - 4), so that the refrigerant liquid is sub-cooled as it enters the expansion device.
- **4 - 1** The high-pressure sub-cooled liquid passes through the expansion device, which both reduces its pressure and controls the flow into the evaporator.

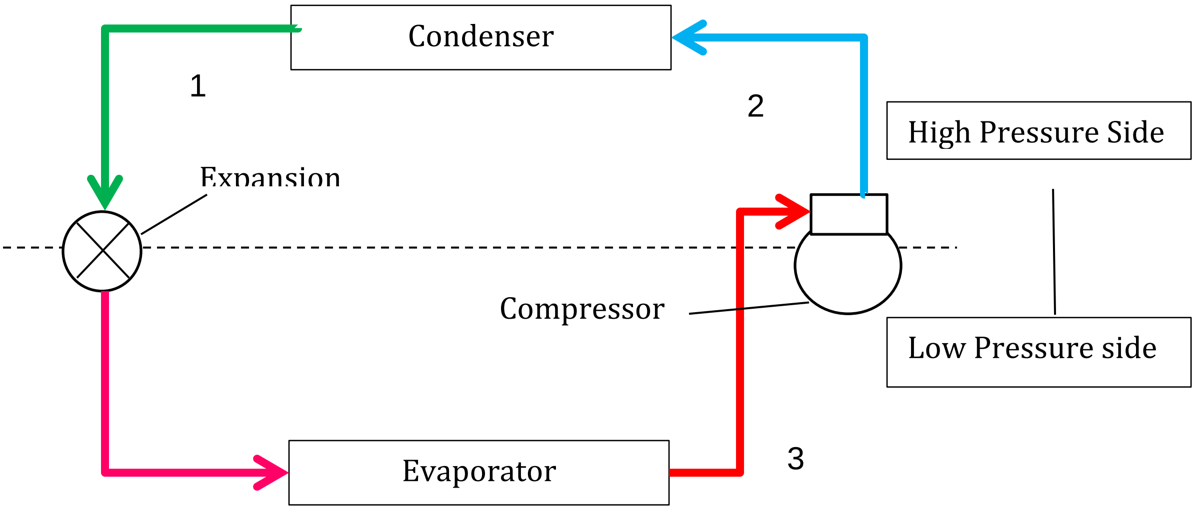


Figure 4.3 Schematic representation of the vapour compression refrigeration cycle

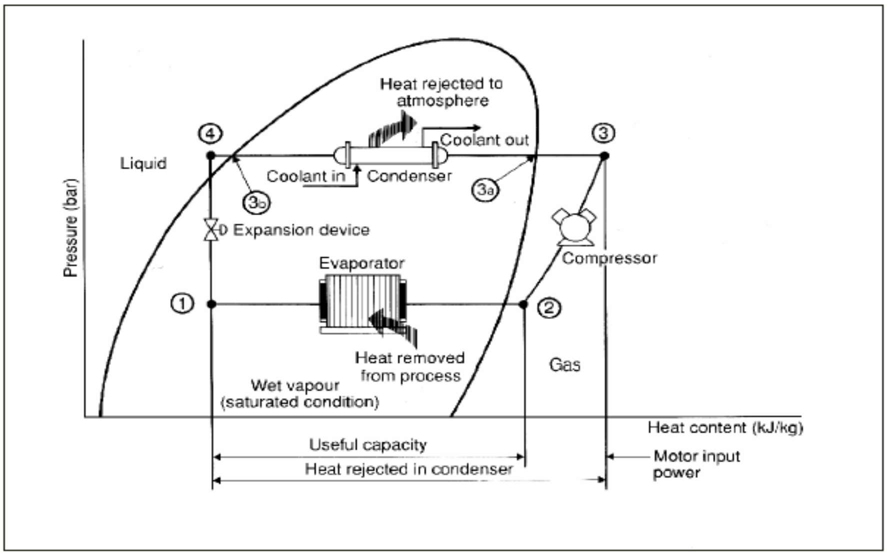


Figure 4 4 Schematic representation of the refrigeration cycle including pressure changes

(Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

The condenser has to be capable of rejecting the combined heat inputs of the evaporator and the compressor. In other words: (1 - 2) + (2 - 3) has to be the same as (3 - 4). There is no heat loss or gain through the expansion device.

4.2.2 Vapour Absorption Refrigeration System

4.2.2.1 Description

The vapour absorption refrigeration system consists of:

- Absorber: Absorption of refrigerant vapour by a suitable absorbent or adsorbent, forming a strong or rich solution of the refrigerant in the absorbent/ adsorbent
- Pump: Pumping of the rich solution and raising its pressure to the pressure of the condenser
- Generator: Distillation of the vapour from the rich solution leaving the poor solution for recycling

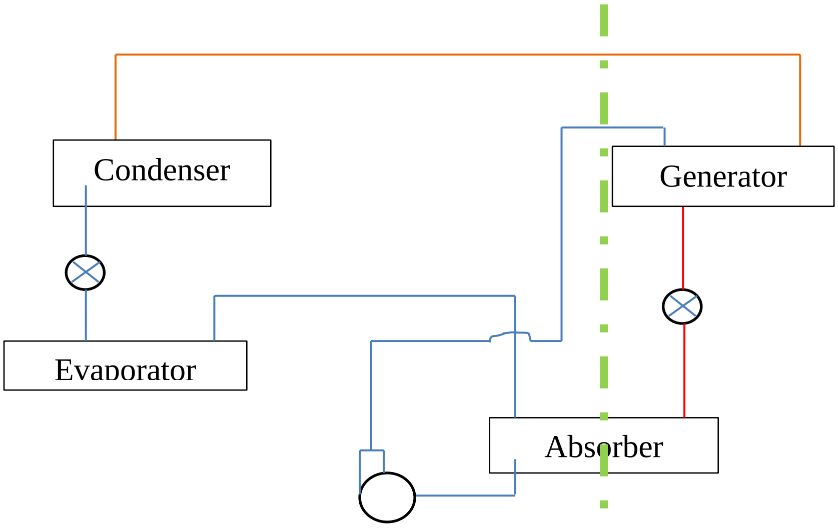
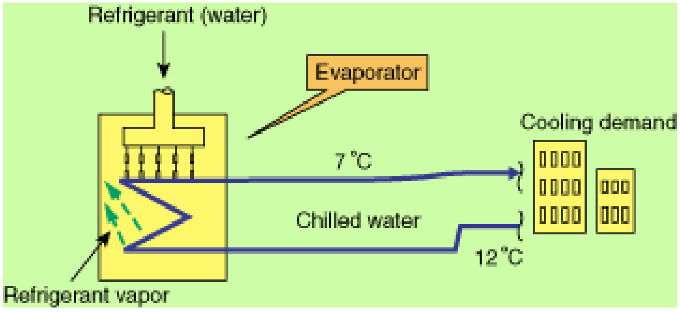
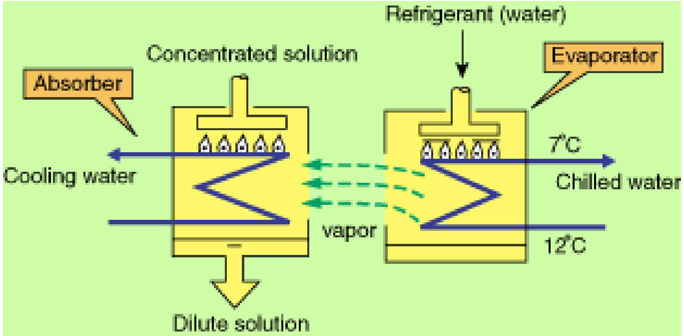


Figure 4.5: A simple schematic of a vapour absorption refrigeration system

The absorption chiller is a machine, which produces chilled water by using heat such as steam, hot water, gas, oil etc. Chilled water is produced based on the principle that liquid (i.e. refrigerant, which evaporates at a low temperature) absorbs heat from its surroundings when it evaporates. Pure water is used as refrigerant and lithium bromide solution is used as absorbent.

Heat for the vapour absorption refrigeration system can be provided by waste heat extracted from the process, diesel generator sets etc. In that case absorption systems require electricity for running pumps only. Depending on the temperature required and the power cost, it may even be economical to generate heat / steam to operate the absorption system.

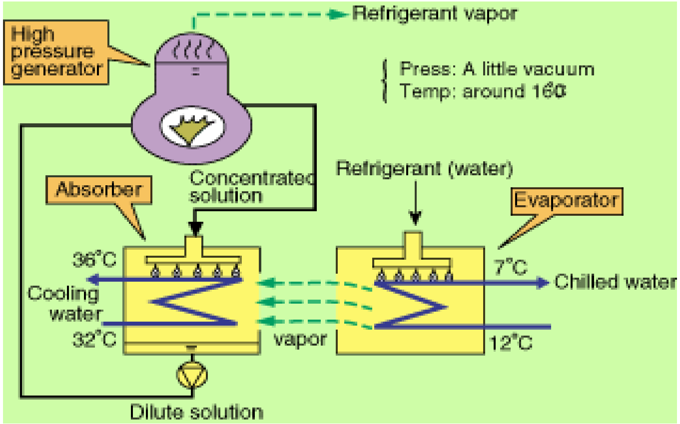
A description of the absorption refrigeration concept is given below (references for the pictures are unknown).

Evaporator The refrigerant (water) evaporates at around 4°C under a high vacuum condition of 754 mm Hg in the evaporator. Chilled water goes through heat exchanger tubes in the evaporator and transfers heat to the evaporated refrigerant. The evaporated refrigerant (vapor) turns into liquid again, while the latent heat from this vaporization process cools the chilled water (in the diagram from 12°C to 7°C). The chilled water is then used for cooling purposes.	
Absorber In order to keep evaporating, the refrigerant vapor must be discharged from the evaporator and refrigerant (water) must be supplied. The refrigerant vapor is absorbed into lithium bromide solution, which is convenient to absorb the refrigerant vapor in the absorber. The heat generated in the absorption process is continuously removed from the system by cooling water. The absorption also maintains the vacuum inside the evaporator.	

High Pressure Generator

As lithium bromide solution is diluted, the ability to absorb the refrigerant vapor reduces. In order to keep the absorption process going, the diluted lithium bromide solution must be concentrated again.

An absorption chiller is provided with a solution concentrating system, called a generator. Heating media such as steam, hot water, gas or oil perform the function of concentrating solutions. The concentrated solution is returned to the absorber to absorb refrigerant vapor again.

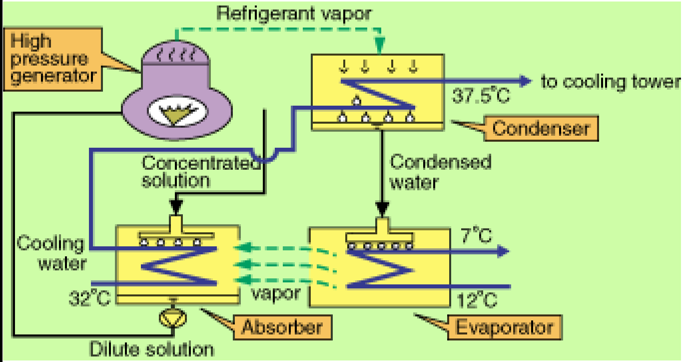


Condenser

To complete the refrigeration cycle and thereby ensuring the refrigeration takes place continuously, the following two functions are required

1. To concentrate and liquefy the evaporated refrigerant vapor, which is generated in the high-pressure generator.
2. To supply the condensed water to the evaporator as refrigerant (water)

For these two functions a condenser is installed.



Absorption refrigeration systems that use Li-Br-water as a refrigerant have a Coefficient of Performance (COP) in the range of 0.65 - 0.70 and can provide chilled water at 6.7 °C with a cooling water temperature of 30 °C. Systems capable of providing chilled water at 3 °C are also available. Ammonia based systems operate at above atmospheric pressures and are capable of low temperature operation (below 0°C). Absorption machines are available with capacities in the range of 10-1500 tons. Although the initial cost of an absorption system is higher than that of a compression system, operational costs are much lower if waste heat is used.

4.2.2.2 Evaporative cooling in vapor absorption refrigeration systems

There are occasions where air conditioning, which stipulates control of humidity of up to 50% for human comfort or for processes, can be replaced by a much cheaper and less energy intensive evaporative cooling.

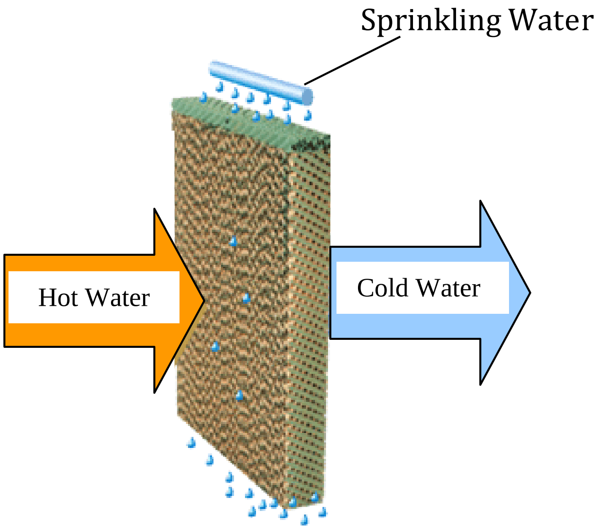


Figure 4.5 Schematic of evaporative cooling - Adapted from: Munters (2001)

The concept is very simple and is the same as that used in a cooling tower. Air is brought in close contact with water to cool it to a temperature close to the wet bulb temperature. The cool air can be used for comfort or process cooling. The disadvantage is that the air is rich in moisture. Nevertheless, it is an extremely efficient means of cooling at very low cost. Large commercial systems employ cellulose filled pads over which water is sprayed. The temperature can be controlled by controlling the airflow and the water circulation rate. The possibility of evaporative cooling is especially attractive for comfort cooling in dry regions. This principle is practiced in textile industries for certain processes.

4.3 Assessment of Refrigeration and Air Conditioning

This section describes how the performance of refrigeration / air conditioning plants and be assessed.

4.3.1 Assessment of Refrigeration

4.3.1.1 TR

We start with the definition of TR.

TR: the cooling effect produced is quantified as tons of refrigeration, also referred to as "chiller tonnage"

$$TR = Q \times C_p \times (T_i - T_o) / 3024$$

Where Q is mass flow rate of coolant in kg/hr

C_p is coolant specific heat in kCal /kg deg C

T_i is inlet, temperature of coolant to evaporator (chiller) in ^{0}C

T_o is outlet temperature of coolant from evaporator (chiller) in^{0}C.

1 TR of refrigeration = 3024 kCal/hr heat rejected

4.3.1.2 Specific Power Consumption

The specific power consumption kW/TR is a useful indicator of the performance of a refrigeration system. By measuring the refrigeration duty performed in TR and the kW inputs, kW/TR is used as an energy performance indicator.

In a centralized chilled water system, apart from the compressor unit, power is also consumed by the chilled water (secondary) coolant pump, the condenser water pump (for heat rejection to cooling tower) and the fan in the cooling tower. Effectively, the overall energy consumption would be the sum of:

- Compressor kW
- Chilled water pump kW
- Condenser water pump kW
- Cooling tower fan kW, for induced / forced draft towers

The kW/TR, or the specific power consumption for a certain TR output is the sum of:

- Compressor kW/TR
- Chilled water pump kW/TR
- Condenser water pump kW/TR
- Cooling tower fan kW/TR

4.3.1.3 Coefficient of Performance

The theoretical Coefficient of Performance (Carnot), (COP_{carnot} a standard measure of refrigeration efficiency of an ideal refrigeration system) depends on two key system temperatures: evaporator temperature T_e and condenser temperature T_c. COP is given as:

$$COP_{Carnot} = T_e / (T_c - T_e)$$

This expression also indicates that higher COP_{Carnot} is achieved with higher evaporator temperatures and lower condenser temperatures. But COP_{Carnot} is only a ratio of temperatures, and does not take into account the type of compressor. Hence the COP normally used in industry is calculated as follows:

$$COP = \frac{\text{Cooling effect (kW)}}{\text{Power input to compressor (kW)}}$$

where the cooling effect is the difference in enthalpy across the evaporator and expressed as kW.

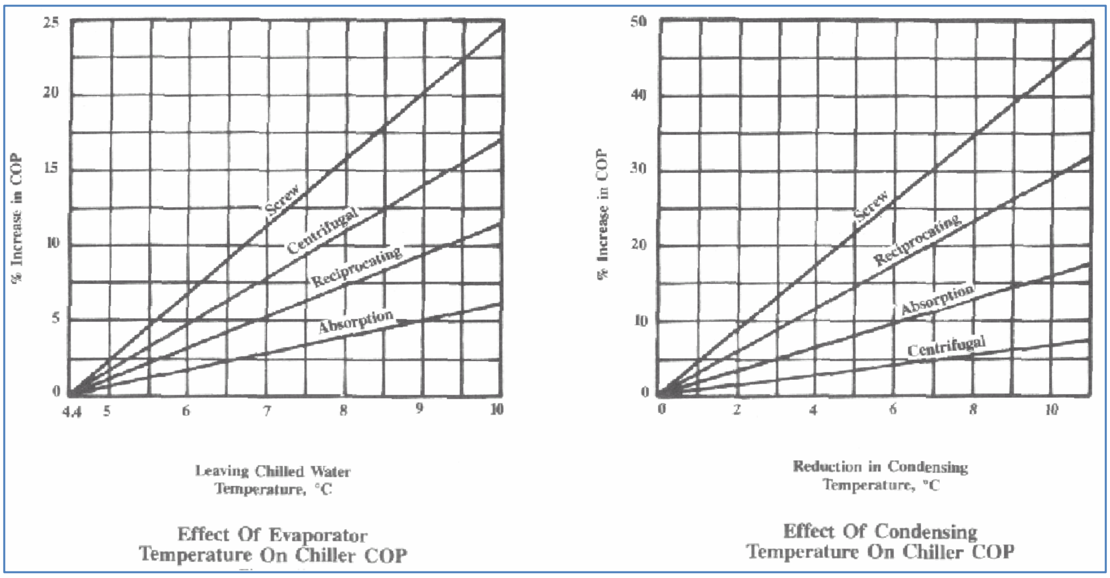


Figure 4.6: The effect of condensing temperature and evaporator temperature on the chiller(Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

4.3.2 Assessment of Air Conditioning

For air conditioning units, the airflow at the Fan Coil Units (FCU) or the Air Handling Units (AHU) can be measured with an anemometer. Dry bulb and wet bulb temperatures are measured at the inlet and outlet of the AHU or the FCU and the refrigeration load in TR is assessed as:

$$TR = \frac{Q \times \rho \times (h_{in} - h_{out})}{3024}$$

Where,

Q is the air flow in m^3/h
ρ is density of air kg/m^3
h_{in} is enthalpy of inlet air kCal/kg
h_{out} is enthalpy of outlet air kCal/kg

Use of psychometric charts can help to calculate h_{in} and h_{out} from dry bulb and wet bulb temperature values which are measured during trials by a whirling psychrometer. Power measurements at compressor, pumps, AHU fans, cooling tower fans can be taken with a portable load analyzer.

Estimation of the air conditioning load is also possible by calculating various heat loads, sensible and latent, based on inlet and outlet air parameters, air ingress factors, air flow, number of people and type of materials stored.

An indicative TR load profile for air conditioning is presented as follows:

Small office cabins	= 0.1 TR/m^2
Medium size office i.e.,10 — 30 people occupancy with central A/C	= 0.06 TR/m^2
Large multistoried office complexes with central A/C	= 0.04 TR/m^2

4.3.3 Considerations when Assessing Performance

4.3.3.1 Accuracy of flow and temperature measurements

In a field performance assessment, accurate instruments are required to measure the inlet and outlet temperatures of chilled water and condenser water, preferably with a count of at least 0.1°C. Flow measurements of chilled water can be made with an ultrasonic flow meter directly or can be determined based on pump duty parameters. Adequacy checks of chilled water are often needed and most units are designed for a typical 0.68 m^3/hr per TR (3 gpm/TR) chilled water flow. Condenser water flow can also be measured with a non-contact flow meter directly or determined by using pump duty parameters. Adequacy checks of condenser water are also needed often, and most units are designed for a typical 0.91 m^3/hr per TR (4 gpm / TR) condenser water flow.

4.3.3.2 Integrated Part Load Value (IPLV)

Although the kW/ TR can serve as an initial reference, it should not be taken as an absolute since this value is based on a 100% equipment capacity level and on design conditions that are considered most critical. These conditions may only occur during a percentage of the total time the equipment is in operation throughout the year. For this reason, it is essential to have data that reflects how the equipment operates with partial loads or under conditions that demand less than 100% capacity. To overcome this, an average kW/TR with partial loads has to be determined, which is called the Integrated Part Load Value (IPLV).

The IPLV is the most appropriate reference, although not considered the best, because it only captures four points within the operational cycle: 100%, 75%, 50% and 25%. Furthermore, it assigns the same weightage to each value, whereas most equipment operates between 50% and 75% of their capacity. This is why it is so important to prepare a specific analysis for each case that addresses the four points mentioned, as well as developing a profile of the heat exchanger's operations during the year.

4.4 Energy Efficiency Opportunities

This section includes areas for energy conservation in refrigeration plants.

4.4.1 Optimization of Process Heat Exchangers

There is a tendency to apply high safety margins to operations, which influence the compressor suction pressure / evaporator set point. For instance, a process-cooling requirement of 15 °C would need chilled water at a lower temperature, but the range can vary from 6 °C to about 10 °C. At chilled water of 10 °C, the refrigerant side temperature has to be lower (about –5°C to +5°C). The refrigerant temperature determines the corresponding suction pressure of the refrigerant, which in turn determines the inlet duty conditions for the refrigerant compressor. Applying the optimum / minimum driving force (temperature difference) can thus help to reach the highest possible suction pressure at the compressor, thereby minimizing energy consumption. This requires proper sizing of heat transfer areas of process heat exchangers and evaporators as well as rationalizing the temperature requirement to highest possible value. A 1°C raise in evaporator temperature can save almost 3% of the power consumed. The TR capacity of the same machine will also increase with the evaporator temperature, as given in the table below.

Table 4.3 Typical values illustrating the effect of variation in evaporator temperature on the compressor power consumption (National Productivity Council, unpublished)

Evaporator Temperature (^0C)	Refrigeration Capacity* (tons)	Specific Power Consumption	Increase in kW/ton (%)
5.0	67.58	0.81	-
0.0	56.07	0.94	16.0
-5.0	45.98	1.08	33.0
-10.0	37.20	1.25	54.0
-20.0	23.12	1.67	106.0

* *Condenser temperature 40^{0}C*

In order to rationalize the heat transfer areas, the heat transfer coefficient on the refrigerant side can range from 1400 –2800 watts /m^2K. The refrigerant side heat transfer areas are of the order of 0.5 m^2/TR and above in evaporators.

Condensers in a refrigeration plant are critical equipment that influence the TR capacity and power consumption demands. For any refrigerant, the condensation temperature and corresponding condenser pressure are dependent on the heat transfer area, the effectiveness of heat exchange and the type of cooling chosen. A lower condensation temperature means that the compressor has to work between a lower pressure differential as the discharge pressure is fixed by design and performance of the condenser.

The choice of condensers in practice is between air-cooled, air-cooled with water spray, and heat exchanger cooled. Larger shell and tube heat exchangers that are used as condensers and that are equipped with good cooling tower operations allow operation at low discharge pressure values and improve the TR capacity of the refrigeration plant.

If the refrigerant R22 is used in a water-cooled shell and tube condenser then the discharge pressure is 15 kg/cm^2. If the same refrigerant is used in an air-cooled condenser then the discharge pressure is 20 kg/cm^2. This shows how much additional compression duty is required, which results in almost 30% additional energy consumption by the plant.

One of the best options at the design stage would be to select large sized (0.65 m^2/TR and above) shell and tube condensers with water-cooling, rather than less expensive alternatives like air cooled condensers or water spray atmospheric condenser units.

The effect of condenser temperature on refrigeration plant energy requirements is given in the table below.

Table 4.4 Typical values illustrating the effect of variation in condensertemperature on compressor power consumption (National Productivity Council, unpublished)

Condensing Temperature (^0C)	Refrigeration Capacity (tons)	Specific Power Consumption (kW / TR)	Increase in kW/TR (%)
26.7	31.5	1.17	-
35.0	21.4	1.27	8
40.0	20.0	1.41	20

* *Reciprocating compressor using R-22 refrigerant. Evaporator temperature -10^{0}C*

4.4.2 Maintenance of Heat Exchanger Surfaces

Once compressors have been purchased, effective maintenance is the key to optimizing power consumption. Heat transfer can also be improved by ensuring proper separation of the lubricating oil and the refrigerant, timely defrosting of coils, and increasing the velocity of the secondary coolant (air, water, etc.). However, increased velocity results in larger pressure drops in the distribution system and higher power consumption in pumps / fans. Therefore, careful analysis is required to determine the optimum velocity.

Fouled condenser tubes force the compressor to work harder to attain the desired capacity. For example, a 0.8 mm scale build-up in condenser tubes can increase energy consumption by as much as 35%. Similarly, fouled evaporators (due to residual lubricating oil or infiltration of air) result in increased power consumption. Equally important is proper selection, sizing, and maintenance of cooling towers. A reduction of 0.55°C in temperature of the water returning from the cooling tower reduces compressor power consumption by 3%.

Table 4.5 Typical values illustrating the effect of poor maintenance on compressor power consumption (National Productivity Council)

Condition	Evaporation Temp (°C)	Condensation Temp (°C)	Refrigeration Capacity* (tons)	Specific Power Consumption (kW/ton)	Increase in kW/Ton (%)
Normal	7.2	40.5	17.0	0.69	-
Dirty condenser	7.2	46.1	15.6	0.84	20.4
Dirty evaporator	7.7	40.5	13.8	0.82	18.3
Dirty condenser and evaporator	7.7	46.1	12.7	0.96	38.7

* *15 ton reciprocating compressor based system. The power consumption is lower than that for systems typically available. However, the percentage change in power consumption is indicative of the effect of poor maintenance.*

4.4.3 Multi -Staging For Efficiency

Efficient compressor operation requires that the compression ratio be kept low, to reduce discharge pressure and temperature. For low temperature applications involving high compression ratios, and for wide temperature range requirements, it is preferable (due to equipment design limitations) and often economical to employ multi-stage reciprocating machines or centrifugal / screw compressors.

There are two types of multi-staging systems, which are applicable to all types of compressors: compound and cascade. With reciprocating or rotary compressors, two-stage compressors are preferable for load temperatures from -20°C to -58°C, and with centrifugal machines for temperatures around -43°C.

In a multi-stage operation, a first-stage compressor that is sized to meet the cooling load, feeds into the suction of a second-stage compressor after inter-cooling of the gas. A part of the high-pressure liquid from the condenser is flashed and used for liquid sub-cooling. The second compressor, therefore, has to meet the load of the evaporator and the flash gas. A single refrigerant is used in the system, and the two compressors share the compression task equally.

Therefore, a combination of two compressors with low compression ratios can provide a high compression ratio. For temperatures in the range of -46°C to -101°C, cascaded systems are preferable. In this system, two separate systems using different refrigerants are connected so that one rejects heat to the other. The main advantage of this system is that a low temperature refrigerant, which has a high suction temperature and low specific volume, can be selected for the low- stage to meet very low temperature requirements.

4.4.4 Matching Capacity to System Load

During part- load operation, the evaporator temperature rises and the condenser temperature falls, effectively increasing the COP. But at the same time, deviation from the design operation point and the fact that mechanical losses form a greater proportion of the total power negate the effect of improved COP, resulting in lower part-load efficiency.

Therefore, consideration of part-load operation is important, because most refrigeration applications have varying loads. The load may vary due to variations in temperature and process cooling needs. Matching refrigeration capacity to the load is a difficult exercise, requiring knowledge of compressor performance, and variations in ambient conditions, and detailed knowledge of the cooling load.

4.4.5 Capacity Control and Energy Efficiency

The capacity of compressors is controlled in a number of ways. Capacity control of reciprocating compressors through cylinder unloading results in incremental (step-by-step) modulation. In contrast, continuous modulation occurs in centrifugal compressors through vane control and in screw compressors through sliding valves. Therefore, temperature control requires careful system design. Usually, when using reciprocating compressors in applications with widely varying loads, it is desirable to control the compressor by monitoring the return water (or other secondary coolant) temperature rather than the temperature of the water leaving the chiller. This prevents excessive on-off cycling or unnecessary loading/unloading of the compressor. However, if load fluctuations are not high, the temperature of the water leaving the chiller should be monitored. This has the advantage of preventing operation at very low water temperatures, especially when flow reduces at low loads. The outgoing water temperature should be monitored for centrifugal and screw chillers.

Capacity regulation through speed control is the most efficient option. However, when employing speed control for reciprocating compressors, it should be ensured that the lubrication system is not affected. In the case of centrifugal compressors, it is usually desirable to restrict speed control to about 50% of the capacity to prevent surging. Below 50%, vane control or hot gas bypass can be used for capacity modulation.

The efficiency of screw compressors operating at part load is generally higher than either centrifugal compressors or reciprocating compressors, which may make them attractive in situations where part- load operation is common. Screw compressor performance can be optimized by changing the volume ratio. In some cases, this may result in higher full-load efficiencies as compared to reciprocating and centrifugal compressors. Also, the ability of screw compressors to tolerate oil and liquid refrigerant slugs makes them preferred in some situations.

4.4.6 Multi -level Refrigeration for Plant Needs

The selection of refrigeration systems also depends on the range of temperatures required in the plant. For diverse applications requiring a wide range of temperatures, it is generally more economical to provide several packaged units (several units distributed throughout the plant) instead of one large central plant. Another advantage would be the flexibility and reliability. The selection of packaged units could also be made depending on the distance at which cooling loads need to be met. Packaged units at load centers reduce distribution losses in the system. Despite the advantages of packaged units, central plants generally have lower power consumption since at reduced loads power consumption can reduce significantly due to the large condenser and evaporator surfaces.

Many industries use a bank of compressors at a central location to meet the load. Usually the chillers feed into a common header from which branch lines are taken to different locations in the plant. In such situations, operation at part- load requires extreme care. For efficient operation, the cooling load, and the load on each chiller must be monitored closely. It is more efficient to operate a single chiller at full load than to operate two chillers at part- load. The distribution system should be designed such that individual chillers can feed all branch lines. Isolation valves must be provided to ensure that chilled water (or other coolant) does not flow through chillers not in operation. Valves should also be provided on branch lines to isolate sections where cooling is not required. This reduces pressure drops in the system and reduces power consumption in the pumping system. Individual compressors should be loaded to their full capacity before operating the second compressor. In some cases it is economical to provide a separate smaller capacity chiller, which can be operated on an on-off control to meet peak demands, with larger chillers meeting the base load.

Flow control is also commonly used to meet varying demands. In such cases the savings in pumping at reduced flow should be weighed against the reduced heat transfer in coils due to reduced velocity. In some cases, operation at normal flow rates, with subsequent longer periods of no-load (or shut-off) operation of the compressor, may result in larger savings.

4.4.7 Chilled Water Storage

Depending on the nature of the load, it is economical to provide a chilled water storage facility with very good cold insulation. Also, the storage facility can be fully filled to meet the process requirements so that chillers need not be operated continuously. This system is usually economical if small variations in temperature are acceptable. This system has the added advantage of allowing the chillers to be operated at periods of low electricity demand to reduce peak demand charges. Low tariffs offered by some electric utilities for operation at nighttime can also be taken advantage of by using a storage facility.

An added benefit is that lower ambient temperature at night lowers condenser temperature and thereby increases the COP.

If temperature variations cannot be tolerated, it may not be economical to provide a storage facility since the secondary coolant would have to be stored at a temperature much lower than required to provide for heat gain. The additional cost of cooling to a lower temperature may offset the benefits. The solutions are case specific. For example, in some cases it may be possible to employ large heat exchangers, at a lower cost burden than low temperature chiller operation, to take advantage of the storage facility even when temperature variations are not acceptable. Ice bank systems, which store ice rather than water, are often economical.

4.4.8 System Design Features

In overall plant design, adoption of good practices improves the energy efficiency significantly. Some areas for consideration are:

- Design of cooling towers with FRP impellers and film fills, PVC drift eliminators, etc.
- Use of softened water for condensers in place of raw water.
- Use of economic insulation thickness on cold lines, heat exchangers, considering cost of heat gains and adopting practices like infrared thermography for monitoring - applicable especially in large chemical / fertilizer / process industry.
- Adoption of roof coatings / cooling systems, false ceilings / as applicable, to minimize refrigeration load.
- Adoption of energy efficient heat recovery devices like air to air heat exchangers to pre-cool the fresh air by indirect heat exchange; control of relative humidity through indirect heat exchange rather than use of duct heaters after chilling.
- Adopting of variable air volume systems; adopting of sun film application for heat reflection;
- Optimizing lighting loads in the air conditioned areas; optimizing number of air changes in the air conditioned areas are few other examples.

4.5 Option Checklist

This section includes most important energy efficiency options.

- Cold Insulation: Insulate all cold lines / vessels using economic insulation thickness to minimize heat gains; and choose appropriate (correct) insulation.
- Building Envelope: Optimize air conditioning volumes by measures such as use of false ceiling and segregation of critical areas for air conditioning by air curtains.
- Building Heat Loads Minimization: minimize the air conditioning loads by measures such as roof cooling, roof painting, efficient lighting, pre-cooling of fresh air by air- to-air heat exchangers, variable volume air system, optimal thermo-static setting of temperature of air conditioned spaces, sun film applications, etc.
- Process Heat Loads Minimization: Minimize process heat loads in terms of TR capacity as well as refrigeration level, i.e., temperature required, by way of:
    - Flow optimization
    - Heat transfer area increase to accept higher temperature coolant
    - Avoiding wastages like heat gains, loss of chilled water, idle flows.
    - Frequent cleaning / de-scaling of all heat exchangers
- At the Refrigeration A/C Plant Area:
    - Ensure regular maintenance of all A/C plant components as per manufacturer guidelines.
    - Ensure adequate quantity of chilled water and cooling water flows and avoid bypass flows by closing valves of idle equipment.
    - Minimize part load operations by matching loads and plant capacity on line and adopt variable speed drives for varying process load.

        - Make efforts to continuously optimize condenser and evaporator parameters for minimizing specific energy consumption and maximizing capacity.
        - Adopt a VAR system where economics permit as a non-CFC solution.
    - Ensure that the AC does not get overloaded and check the fuse or circuit breaker if the AC does not operate.
    - Replace or clean the filter and clean the evaporator and condenser coils regularly, for the air conditioner to cool efficiently.
    - Clean the thermostat regularly and replace it if necessary.
    - If a compressor does not work properly, call a service person immediately
    - Any noise that the AC makes needs to be checked by the mechanic.
    - A good air filter will extend the life of the air conditioner because the important parts, like the blower assembly, the cooling coil, and other inner parts will stay cleaner, operate more efficiently and last longer.
    - Avoid frequent opening of doors/windows. A door kept open can result in doubling the power consumption of the AC.
    - Ensure direct sunlight and heat does not enter the air-conditioned space, particularly in the afternoons.
    - Most people believe that a thermostat set to a lower temperature than desired will force the air-conditioner to cool faster, not in reality, all it does, is make the air-conditioner operate for longer. Moreover, it will result in an unnecessarily chilly room and wasted power. Every degree lower on the temperature setting results in an extra 3-4% of power consumed. Hence, once a comfortable temperature is identified, thermostat should be set at that level.
- Once an air-conditioning system has been designed and installed any major change in the heat-load on the AC should be avoided. This will add to wasted power.
- A clogged drain line is usually caused by algae (the green moss-like stuff!) build-up inside the drain line. The air handler provides a cool, damp environment for development of molds and mildew and if left untreated these growths can spread into the ductwork. These molds can be removed by using a disinfectant (consult the dealer). Make sure that the face of the cooling or evaporator coil is clean so that air can pass through freely.
- If an air return duct is in a hot area such as an attic or garage, it should be ensured that this duct is not broken, split, or disconnected and sucking in hot air.
- Window unit should tilt down slightly on the outside. The part that removes humidity (where water accumulates) is the front coil, which is inside the home. Normally, there is a trough and/or a drain tube that lets the water run to the rear of the unit. If the drain gets clogged, water will back up and leak inside. The mechanic should clean the chassis and make sure all screws are tight.
- Heat load can be reduced by keeping a false ceiling in offices. Curtains/ blinds /sun film on windows reduce heat input into the room. Insulating the ceiling, which is exposed to the sun with 50-mm thermocole drastically, reduces heat input into the room.
- Check for duct leaks and crushed ductwork. All air leaks should be sealed with a good quality duct sealant (not duct tape).
- Inspect the chiller as recommended by the chiller manufacturer. Typically, this should be done at least quarterly.
- Routinely inspect for refrigerant leaks.
- Check the compressor operating pressures.
- Check all oil levels and pressures.
- Examine all motor voltages and currents.
- Check all electrical starters, contactors, and relays.
- Check all hot gas and unloader operations.

- Use superheat and subcooling temperature readings to obtain a chiller's maximum efficiency.
- Take discharge line temperature readings.

Some **'Rules of Thumb"** are:

- Refrigeration capacity reduces by 6 percent for every 3.5°C increase in condensing temperature.
- Reducing condensing temperature by 5.5°C results in a 20 – 25 percent decrease in compressor power consumption.
- A reduction of 0.55°C in cooling water temperature at condenser inlet reduces compressor power consumption by 3 percent.
- 1 mm scale build-up on condenser tubes can increase energy consumption by 40 percent.
- 5.5°C increase in evaporator temperature reduces compressor power consumption by 22-25 percent.

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Chapter 5 Fans and Blowers

5.1 Introduction

This section describes the main features of fans and blowers.

5.1.1 What are fans and blowers?

Most manufacturing plants use fans and blowers for ventilation and for industrial processes that need an air flow. Fan systems are essential to keep manufacturing processes working, and consist of a fan, an electric motor, a drive system, ducts or piping, flow control devices, and air conditioning equipment (filters, cooling coils, heat exchangers, etc.). An example system is illustrated in Figure 1. A study of the pumps, fans and blowers in industries shows that it constitutes 55% of the total motor loads in Pakistan[1].

Fans, blowers and compressors are differentiated by the method used to move the air, and by the system pressure they must operate against. The American Society of Mechanical Engineers (ASME) uses the specific ratio, which is the ratio of the discharge pressure over the suction pressure, to define fans, blowers and compressors given in Table 5.1.

Table 5.1: Difference between Fans, Blowers and Compressors

Equipment	Specific Ratio	Pressure rise (mmW
Fans	up to 1.11	1136
Blowers	1.11 to 1.20	1136 –2066
Compressors	more than 1.20	-

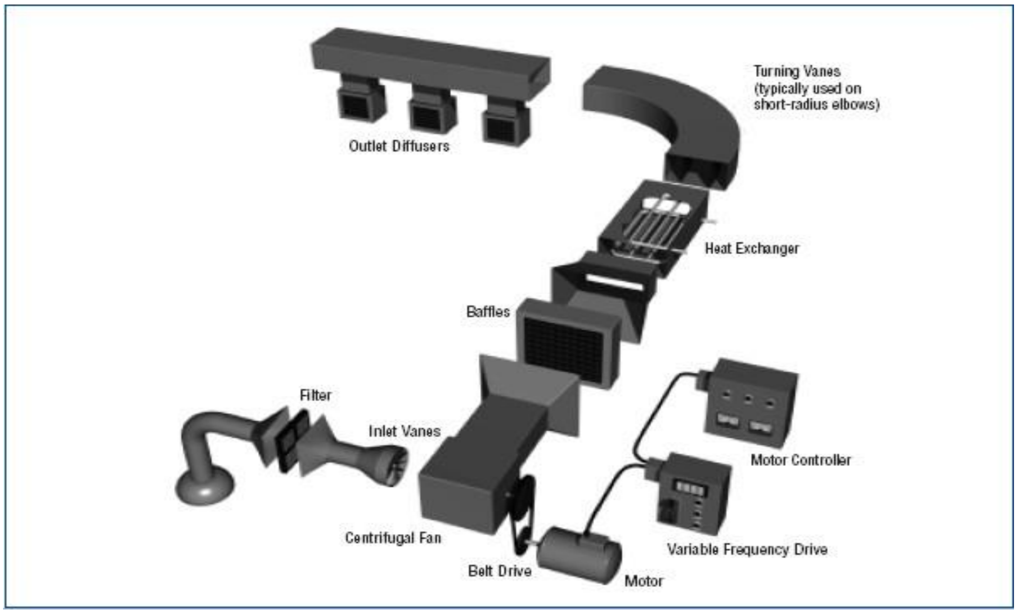

Figure 5.1: Typical Fan System Components (US DOE, 1989)

[1]Demand side management and electricity end use efficiency[1]

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[1] Demand side management and electricity end use efficiency[1]

5.1.2 Important terms and definitions

Before types of fans and blowers are described it is important to first understand terms and definitions.[2]

5.1.2.1 System characteristics

The term "system resistance" is used when referring to the static pressure. The system resistance is the sum of static pressure losses in the system. The system resistance is a function of the configuration of ducts, pickups, elbows and the pressure drops across equipment, for example bag filter or cyclone. The system resistance varies with the square of the volume of air flowing through the system. For a given volume of air, the fan in a system with narrow ducts and multiple short radius elbows is going to have to work harder to overcome a greater system resistance than it would in a system with larger ducts and a minimum number of long radius turns. Long narrow ducts with many bends and twists will require more energy to pull the air through them. Consequently, for a given fan speed, the fan will be able to pull less air through this system than through a short system with no elbows. Thus, the system resistance increases substantially as the volume of air flowing through the system increases; square of air flow.

Conversely, resistance decreases as flow decreases. To determine what volume the fan will produce, it is therefore necessary to know the system resistance characteristics. In existing systems, the system resistance can be measured. In systems that have been designed, but not built, the system resistance must be calculated. Typically a system resistance curve (see Figure 5.2) is generated with for various flow rates on the x-axis and the associated resistance on the y-axis.

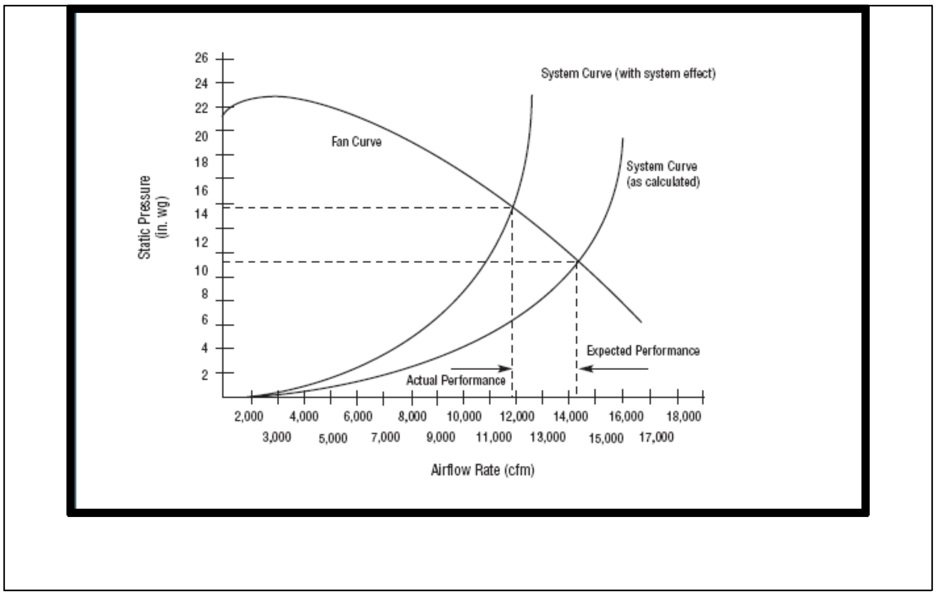

Figure 5.2 System Curve of a Fan and Effect of System Resistance (US DOE, 1989)

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[2] Except for Figure 5.2, Section 1.2 is taken (with edits) from *Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment: Fans and Blowers*

5.1.2.2 Fan characteristics

Fan characteristics can be represented in form of fan curve(s). The fan curve is a performance curve for the particular fan under a specific set of conditions. The fan curve is a graphical representation of a number of inter-related parameters. Typically a curve will be developed for a given set of conditions usually including: fan volume, system static pressure, fan speed, and brake horsepower required to drive the fan under the stated conditions. Some fan curves will also include an efficiency curve so that a system designer will know where on that curve the fan will be operating under the chosen conditions (see Figure 5.3). Of the many curves shown in the figure, the curve static pressure (SP) versus flow is especially important.

The intersection of the system curve and the static pressure curve defines the operating point. When system resistance changes, the operating point will also change. Once the operating point is fixed, the power required can be determined by following a vertical line that passes through the operating point to an intersection with the power (BHP) curve. A horizontal line drawn through the intersection with the power curve will lead to the required power on the right vertical axis. In the depicted curves, the fan efficiency curve is also presented.

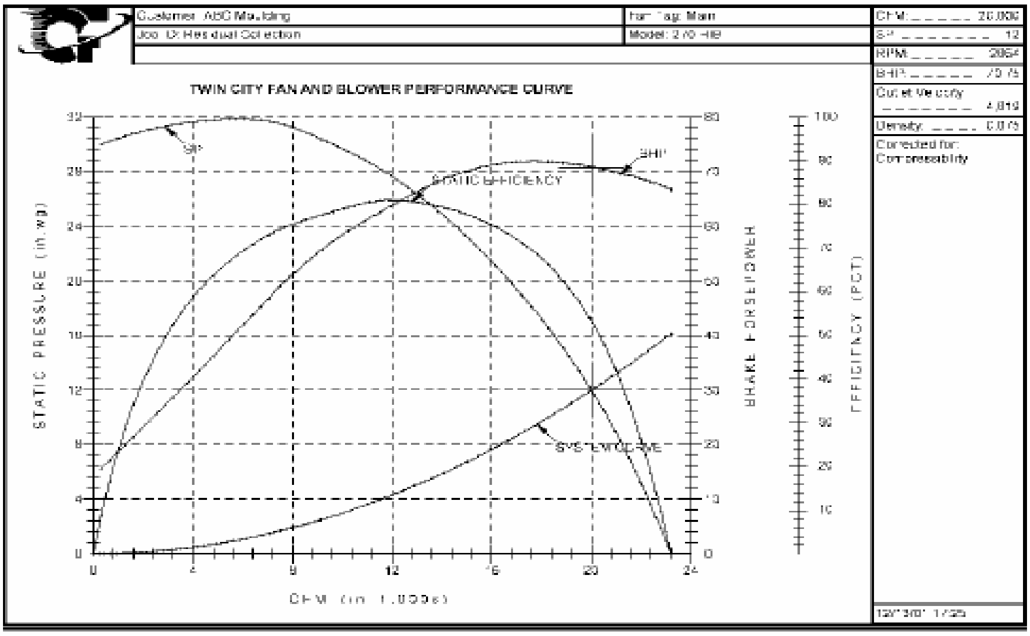


Figure 5.3 Typical Fan Efficiency Curve (Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment: Fans and Blowers)

5.1.2.3 System characteristics and fan curves

In any fan system, the resistance to air flow (pressure) increases when the flow of air is increased. As mentioned before, it varies as the square of the flow. The pressure required by a system over a range of flows can be determined and a "system performance curve" can be developed (shown as SC) (see Figure 5.4).

This system curve can then be plotted on the fan curve to show the fan's actual operating point at "A" where the two curves (N_1 and SC_1) intersect. This operating point is at air flow Q_1 delivered against pressure P_1. A fan operates at a performance given by the manufacturer for a particular fan speed. (The fan performance chart shows performance curves for a series of fan speeds.) At fan speed N_1, the fan will operate along the N_1 performance curve as shown in Figure 4. The fan's actual operating point on this curve will depend on the system resistance; fan’s operating point at “A” is flow (Q_1) against pressure (P_1).

Two methods can be used to reduce air flow from Q_1 to Q_2:

- The first method is to restrict the air flow by partially closing a damper in the system. This action causes a new system performance curve (SC_2) where the required pressure is greater for any given air flow. The fan will now operate at "B" to provide the reduced air flow Q_2 against higher pressure P_2.
- The second method to reduce air flow is by reducing the speed from N_1 to N_2, keeping the damper fully open. The fan would operate at "C" to provide the same Q_2 air flow, but at a lower pressure P_3. Thus, reducing the fan speed is a much more efficient method to decrease airflow since less power is required and less energy is consumed.

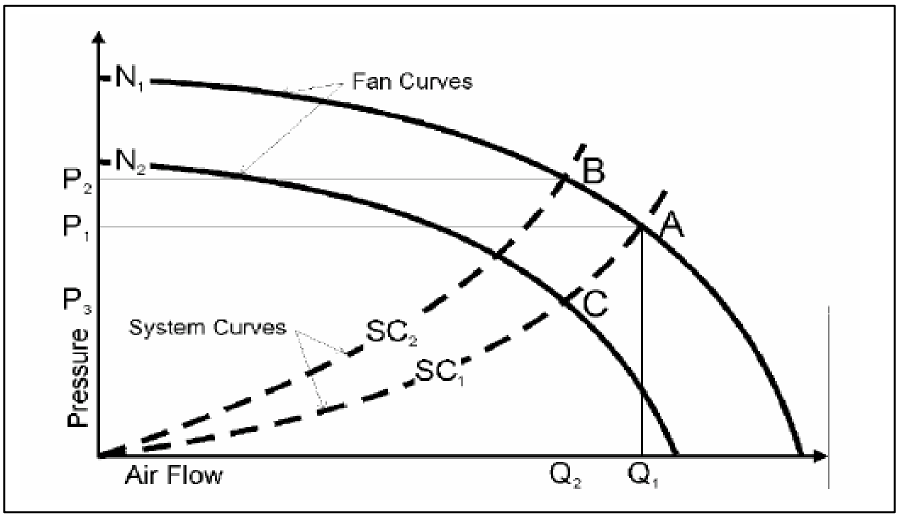
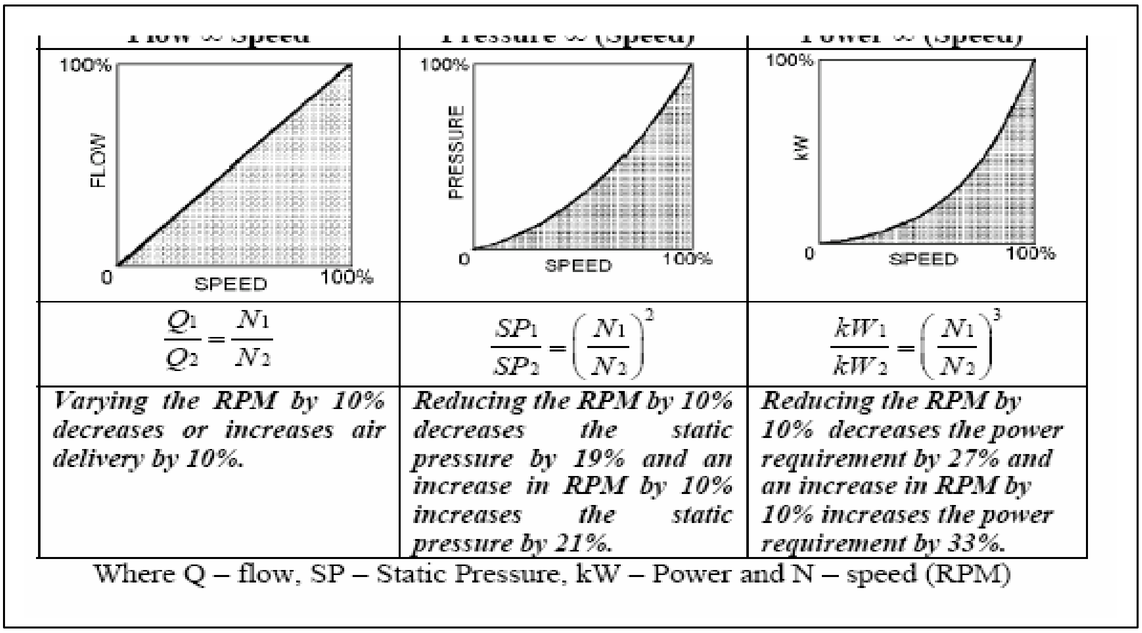


Figure 5.4 Fan performance curve (Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

5.2.4 Fan laws

The fans operate under a predictable set of laws concerning speed, power and pressure. A change in speed (revolutions per minute or RPM) of any fan will predictably change the pressure rise and power necessary to operate it at the new RPM. This is shown in Figure 5.5.



$\frac{Q_1}{Q_2} = \frac{N_1}{N_2}$	$\frac{SP_1}{SP_2} = \left(\frac{N_1}{N_2}\right)^2$	$\frac{kW_1}{kW_2} = \left(\frac{N_1}{N_2}\right)^3$
Varying the RPM by 10% decreases or increases air delivery by 10%.	*Reducing the RPM by 10% decreases the static pressure by 19% and an increase in RPM by 10% increases the static pressure by 21%.*	*Reducing the RPM by 10% decreases the power requirement by 27% and an increase in RPM by 10% increases the power requirement by 33%.*

Where Q – flow, SP – Static Pressure, kW – Power and N – speed (RPM)

Figure 5.5 Speed, pressure and power of fans (Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

5.2 Type of fans and blowers

This section briefly describes different types of fans and blowers.

5.2.1 Types of fans

There exist two main fan types. Centrifugal fans used a rotating impeller to move the air stream. Axial fans move the air stream along the axis of the fan.

5.2.1.1 Centrifugal fans

Centrifugal fans (Figure 5.6) increase the speed of an air stream with a rotating impeller. The speed increases as air reaches the ends of the blades and is then converted to pressure. These fans are able to produce high pressures, which makes them suitable for harsh operating conditions, such as systems with high temperatures, moist or dirty air streams, and material handling. Centrifugal fans are categorized by their blade shapes as summarized in Table 5.2.

Table 5.2 Characteristics of Different Centrifugal Fans (adapted from US DOE, 1989)

Type of fan and blade	Advantages	Disadvantages
Radial fans, with flat blades (Figure 5.7)	• Suitable for high static pressures (up to 1400 mmWC) and high temperatures. • Simple design allows custom build units for special applications. • Can operate at low air flows without vibration problems. • High durability. • Efficiencies up to 75%. • Have large running clearances, which is useful for airborne solids (dust, wood chips and metal scraps) handling services	• Only suitable for low-medium airflow rates
Forward curved fans, with forward curved blades (Figure 5.8)	• Can move large air volumes against relatively low pressure • Relative small size • Low noise level (due to low speed) and well suited for residential heating, ventilation, and air conditioning (HVAC) applications	• Only suitable for clean service • applications but not for high • pressure and harsh services • Fan output is difficult to adjust • accurately • Driver must be selected carefully to avoid motor overload because power curve increases steadily with airflow • Relatively low energy efficiency • (55-65%)

Backward inclined fan, with blades that tilt away from the direction of rotation: flat, curved, and airfoil (Figure 5.9)	• Can operate with changing static pressure (as this does not overload the motor). • Suitable when system behavior at high air flow is uncertain. • Suitable for forced-draft services. • Flat bladed fans are more robust. • Curved blades fans are more efficient (exceeding 85%) • Thin air-foil blades fans are most to erosion efficient	• Not suitable for dirty air streams (as fan shape promotes accumulation of dust) • Airfoil blades fans are less stable because of staff as they rely on the lift created by each blade • Thin airfoil blades fans subject to erosion efficient

Figure 5.6. Centrifugal Fan
(Fan Air Company)

Figure 5.7. Radial Blade Centrifugal Fan (Canadian Blower)

Figure 5.8. Forward-Curved Fan (Canadian Blower)

Figure 5.9. Backward Inclined Fan
(Canadian

5.2.1.2 Axial fans

Axial fans (Figure 5.10) move an air stream along the axis of the fan. The way these fans work can be compared to a propeller on an airplane: the fan blades generate an aerodynamic lift that pressurizes the air. They are popular with industry because they are inexpensive, compact and light. The main types of axial flow fans (propeller, tube-axial and vane-axial) are summarized in Table 5.3.

Table 5.3 Characteristics of Different Axial Fans (adapted from US DOE, 1989)

Type of fan	Advantages	Disadvantages
Propeller fan (Figure 5.11)	• Generate high airflow rates at low pressures • Not combined with extensive ductwork (because they generate little pressure) • Inexpensive because of their simple construction • Achieve maximum efficiency, near-free delivery, and are often used in rooftop ventilation applications • Can generate flow in reverse direction, which is	• Relatively low energy efficiency • Comparatively noisy
Tube-axial fan, essentially a propeller fan placed inside a cylinder (Figure 5. 12)	• Higher pressures and better operating efficiencies than propeller fans • Suited for medium-pressure, high airflow rate applications, e.g. ducted HVAC installations • Can quickly accelerate to rated speed (because of their low rotating mass) and generate flow in reverse direction, which is useful in many ventilation applications • Create sufficient pressure to overcome duct losses and are relatively space efficient, which is useful for exhaust applications	• Relatively Expensive • Moderate airflow noise • Relatively low energy efficiency (65%)
Vane-axial fan (Figure 5.13)	• Suited for medium- to high-pressure applications (up to 500 mm WC), such as induced draft service for a boiler exhaust. • Can quickly accelerate to rated speech (because of their low rotating mass) and generate flow in reverse directions, which is useful in many ventilation applications. • Suitable for direct connection to motor shafts. • Most energy efficient (up to 85% if equipped with airfoil fans and small clearances.	• Relatively expensive compared to propeller fans

Figure 5.10. Axial Fan (NISCO)

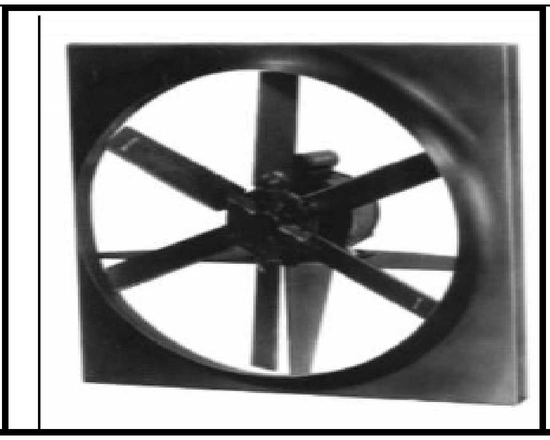


Figure 5.11. Propeller Fans (Fan Air company)

Figure 5.12. Tube Axial Fan (NISCO)

Figure 5.13. Vane-axial Fan (NISCO)

5.2.2 Types of blowers

Blowers can achieve much higher pressures than fans, as high as 1.20 kg/cm^2. They are also used to produce negative pressures for industrial vacuum systems. The centrifugal blower and the positive displacement blower are two main types of blowers, which are described below.[3]

5.2.2.1 Centrifugal blowers

Centrifugal blowers look more like centrifugal pumps than fans. The impeller is typically gear-driven and rotates as fast as 15,000 rpm. In multi-stage blowers, air is accelerated as it passes through each impeller. In single-stage blower, air does not take many turns, and hence it is more efficient.

Centrifugal blowers typically operate against pressures of 0.35 to 0.70 kg/cm^2, but can achieve higher pressures. One characteristic is that airflow tends to drop drastically as system pressure increases, which can be a disadvantage in material conveying systems that depend on a steady air volume. Because of this, they are most often used in applications that are not prone to clogging.

Figure 5.14 Centrifugal Blower (Fan Air Company)

5.2.3 Positive-displacement blowers

Positive displacement blowers have rotors, which "trap" air and push it through housing. These blowers provide a constant volume of air even if the system pressure varies. They are especially suitable for applications prone to clogging, since they can produce enough pressure (typically up to 1.25 kg/cm^2) to blow clogged materials free. They turn much slower than centrifugal blowers (e.g. 3,600 rpm) and are often belt driven to facilitate speed changes.

5.3 Assessment of Fans and Blowers

This section describes how to evaluate the performance of fans, but it is also applicable to blowers.

5.3.1 What is fan efficiency / performance?

Fan efficiency is the ratio between the power transferred to the air stream and the power delivered by the motor to the fan. The power of the airflow is the product of the pressure and the flow, corrected for unit consistency.

Another term for efficiency that is often used with fans is static efficiency, which uses static pressure instead of total pressure in estimating the efficiency. When evaluating fan performance, it is important to know which efficiency term is being used.

The fan efficiency depends on the type of fan and impeller. As the flow rate increases, the efficiency increases to certain height ("peak efficiency") and then decreases with further increasing flow rate (see Figure 14). The peak efficiency ranges for different types of centrifugal and axial fans are given in Table 4.

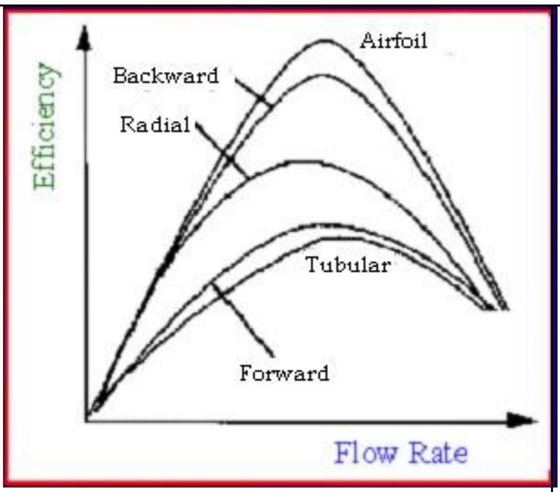
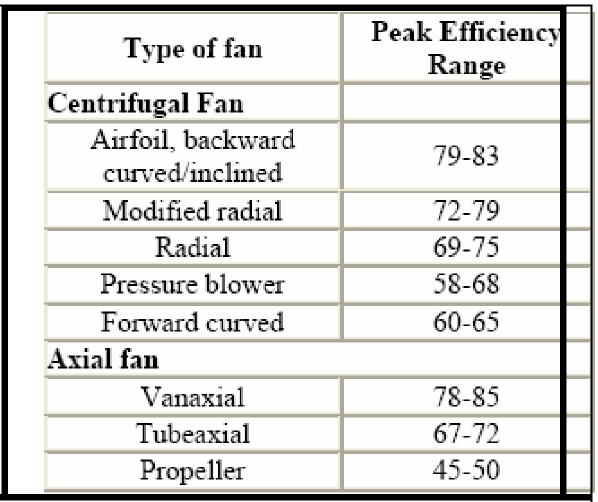


Figure 5.15. Efficiency versus Flowrate
(Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)



Type of fan	Peak Efficiency Range
Centrifugal Fan	
Airfoil, backward curved/inclined	79-83
Modified radial	72-79
Radial	69-75
Pressure blower	58-68
Forward curved	60-65
Axial fan	
Vanaxial	78-85
Tubeaxial	67-72
Propeller	45-50

Figure 5.16. Efficiency of Various Fans
(Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

Fan performance is typically estimated by using a graph that shows the different pressures developed by the fan and the corresponding required power. The manufacturers normally provide these fan performance curves. Understanding this relationship is essential to designing, sourcing, and operating a fan system and is the key to optimum fan selection.

5.3.2 Methodology of fan performance assessment

Before the fan efficiency can be calculated, a number of operating parameters must be measured, including air velocity, pressure head, temperature of air stream on the fan side and electrical motor kW input. In order to obtain correct operating figures it should be ensured that:

- Fan and its associated components are operating properly at its rated speed
- Operations are at stable condition i.e. steady temperature, densities, system resistance etc.

The calculation of fan efficiency is explained in 5 steps.

Step 1: calculate the gas density

The first step is to calculate the air or gas density using the following equation:

$$Gas\ density\ (y) = \frac{273 \times 1.293}{273 + t^{\circ}C}$$

Where, t ^{o}C = Temperature of air or gas at site condition

Step 2: measure the air velocity and calculate average air velocity

The air velocity can be measured with a pitot tube and a manometer, or a flow sensor (differential pressure instrument), or an accurate anemometer. Figure 15 shows how the velocity pressure is measured using a pitot tube and a manometer. The total pressure is measured using the inner tube of pitot tube and static pressure is measured using the outer tube of pitot tube. When the inner and outer tube ends are connected to a manometer, we get the velocity pressure (i.e. the difference between total pressure and static pressure). For measuring low velocities, it is preferable to use an inclined tube manometer instead of U-tube manometer.

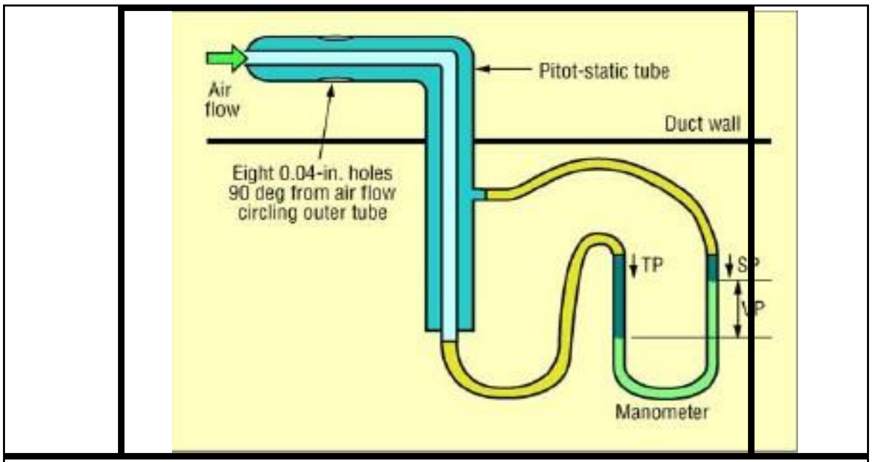


Figure 5.17 Velocity Pressure Measurement using Pilot Tube
(Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

Calculate the average air velocity by taking number of velocity pressure readings across the cross-section of the duct using the following equation (note: do not average the velocity pressure, but average the velocities!):

$$\text{Velocity v, m/s} = \frac{C_p \ \text{x} \ \sqrt{2 \times 9.81 \times \Delta p \times \gamma}}{\gamma}$$

Where:

C_p = Pitot tube constant, 0.85 (or) as given by the manufacturer

Δp = Average differential pressure measured by pitot tube by taking measurement at number of points over the entire cross section of the duct.

γ = Density of air or gas at test condition

Step 3: calculate the volumetric flow

The third step is to calculate the volumetric flow as follows:
Take the duct diameter (or the circumference from which the diameter can be estimated).
Calculate the volume of air/gas in the duct by following relation

$$Volumetric\ flow(Q), m^3/\sec = Velocity, V\,(m/\sec)\ x\ Area\,(m^2)$$

Step 4: measure the power of the drive motor

The power of the drive motor (kW) can be measured by a load analyzer. This kW multiplied by motor efficiency gives the shaft power to the fan.

Step 5: calculate the fan efficiency

Now the fan's mechanical and static efficiencies can be calculated as follows:

a). Mechanical efficiency:

$$Fan\ Mechanical\ Efficiency\,(\eta_{mechanical}), \% = \frac{Volume\ in\ m^3/\sec * \Delta p\,(total\ pressure)\ in\ mmWC}{102 * power\ input\ to\ fan\ shaft\ in\ kW}\ x\ 100$$

b) Static efficiency, which is the same except that the outlet velocity pressure is not added to the fan static pressure:

$$Fan\ Static\ Efficiency\,(\eta_{static}), \% = \frac{Volume\ in\ m^3/\sec * \Delta p\,(static\ pressure)\ in\ mmWC}{102 * power\ input\ to\ fan\ shaft\ in\ kW}\ x\ 100$$

5.3.3 Difficulties in assessing the performance of fans and blowers

In practice certain difficulties have to be faced when assessing the fan and blower performance, some of which are explained below:

Non-availability of fan specification data: Fan specification data are essential to assess the fan performance. Most of the industries do not keep these data systematically or have none of these data available at all. In these cases, the percentage of fan loading with respect to flow or pressure cannot be estimated satisfactorily. Fan specification data should be collected from the original equipment manufacturer (OEM) and kept on record.

Difficulty in velocity measurement: Actual velocity measurement becomes a difficult task in fan performance assessment. In most cases the location of duct makes it difficult to take measurements and in other cases it becomes impossible to traverse the duct in both directions. If this is the case, then the velocity pressure can be measured in the center of the duct and corrected by multiplying it with a factor 0.9.

Improper calibration of the pitot tube, manometer, anemometer & measuring instruments: All instruments and other power measuring instruments should be calibrated correctly to avoid an incorrect assessment of fans and blowers. Assessments should not be carried out by applying correction factors to compensate for this.

Variation of process parameters during tests: If there is a large variation of process parameters measured during test periods, then the performance assessment becomes unreliable.

5.4 Energy Efficiency Opportunities

This section describes the most important energy efficiency opportunities for fans and blowers.

5.4.1 Choose the right fan

Important considerations when selecting a fan are (US DOE, 1989):

- Noise
- Rotational speed
- Air stream characteristics
- Temperature range
- Variations in operating conditions
- Space constraints and system layout
- Purchase costs, operating costs (determined by efficiency and maintenance), and operating life

But as a general rule it is important to know that to effectively improve the performance of fan systems, designers and operators must understand how other system components function as well. The “systems approach” requires knowing the interaction between fans, the equipment that supports fan operation, and the components that are served by fans. The use of a “systems approach” in the fan selection process will result in a quieter, more efficient, and more reliable system.

A common problem is that companies purchase oversized fans for their service requirements. They will not operate at their best efficiency point (BEP) and in extreme cases these fans may operate in an unstable manner because of the point of operation on the fan airflow- pressure curve. Oversized fans generate excess flow energy, resulting in high airflow noise and increased stress on the fan and the system. Consequently, oversized fans not only cost more to purchase and to operate, they create avoidable system performance problems. Possible solutions include, amongst other replacing the fan, replacing the motor, or introducing a variable speed drive motor.

5.4.2 Reduce the system resistance

The system resistance curve and the fan curve were explained in section 1.2. The fan operates at a point where the system resistance curve and the fan curve intersects. The system resistance has a major role in determining the performance and efficiency of a fan. The system resistance also changes depending on the process. For example, the formation of the coatings / erosion of the lining in the ducts, changes the system resistance marginally. In some cases, the change of equipment, duct modifications, drastically shift the operating point, resulting in lower efficiency (See Figure 2). In such cases, to maintain the efficiency as before, the fan has to be changed.

Hence, the system resistance has to be periodically checked, more so when modifications are introduced and action taken accordingly, for efficient operation of the fan.

5.4.3 Operate close to BEP

It is earlier described that the fan efficiency increases as the flow increases to certain point and thereafter it decreases. The point at which maximum efficiency is obtained is called the peak efficiency or “Best Efficiency Point” (BEP). Normally it is closer to the rated capacity of the fan at a particular designed speed and system resistance. Deviation from the BEP will result in increased loss and inefficiency.

5.4.4 Maintain fans regularly

Regular maintenance of fans is important to maintain their performance levels. Maintenance activities include (US DOE, 1989):

- Periodic inspection of all system components
- Bearing lubrication and replacement
- Belt tightening and replacement
- Motor repair or replacement
- Fan cleaning

5.4.5 Control the fan air flow

Normally, an installed fan operates at a constant speed. But some situations may require a speed change, for example more airflow may be needed from the fan when a new run of duct is added, or less air flow may be needed if the fan is oversized. There are several ways to reduce or control the airflow of fans. These are summarized in Table 5.5 and a comparison of full load power against percentage full flow by different flow control is given in Figure 5.18.

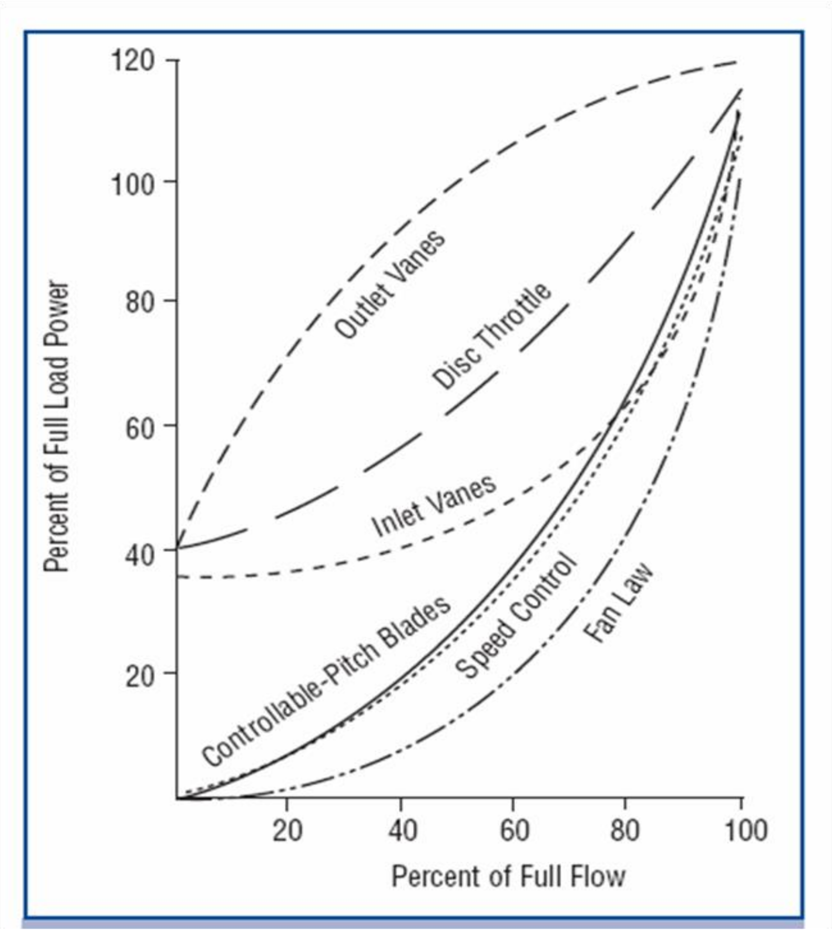


Figure 5.18. Relative Power Consumption among Flow Control Options (US DOE, 1989)

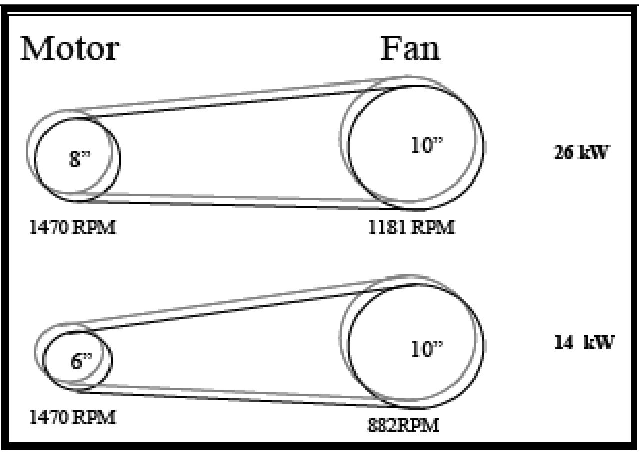


Figure 5.19 Pulley Dimension Change (Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers

Table 5.4 Comparison of Different Ways to Control Fan Flow (adapted from Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

Type of flow control	Advantages	Disadvantages
Pulley change: reduces the motor / drive pulley size	• Permanent speed decrease • Real energy reduction (see Figure 18: a 2 inch reduction in pulley results in	• Fan must be able to handle capacity change • Fan must be driven by belt system or motor
Dampers: reduce the amount of flow and increases the upstream pressure, which reduces fan output	• Inexpensive • Easy to install	• Provide a limited amount of adjustment • Reduce the flow but not the energy consumption • Higher operating and maintenance costs
Inlet guide vanes: create swirls in the fan direction thereby lessening the angle between incoming air and fan blades, and thus lowering fan load, pressure and Airflow	• Improve fan efficiency because both fan load and delivered airflow are reduced • Cost effective at airflows between 80-100% of full flow	• Less efficient at airflows lower than 80% of full flow
Variable pitch fans: change the angle between incoming airflow and the blade by tilting the fan blades, thereby reducing both the motor load and airflow	• Can keep fan efficiency high over a range of operating conditions. • Avoid resonance problems as normal operating speed is maintained • Can operate from a no-flow to a full- flow condition without stall problems	• Applicable to some axial fan types only • Fouling problems if contaminants accumulate in the mechanical actuator that controls the blades. • Operating at low loads for long periods reduces the power factor and motor efficiency, thus loosing efficiency advantages and risking low power factor charge from the utility
• Variable Speed Drive (VSD): reducing the speed of motor of the fan to meet reduced flow requirements • Mechanical VSDs: hydraulic clutches, fluid couplings, and adjustable belts and pulleys • Electrical VSDs: eddy current clutches, wound- rotor motor controllers, and variable frequency drives (VFDs: change motor's rotational speed by adjusting electrical frequency of power supplied)	• Most improved and efficient flow control • Allow fan speed adjustments over a continuous range • For VFDs specifically: • Effective and easy flow control • Improve fan operating efficiency over a wide range of operating conditions • Can be retrofitted to existing motors • Compactness • No fouling problems • Reduce energy losses and costs by lowering overall system flow	• Mechanical VSDs have fouling problems • Investment costs can be a barrier

Dual speed motor	• Efficient control of flow • Suitable if only two fixed speeds are required	• Need to jump from speed to speed • Investment costs can be a barrier
Disc throttle: a sliding throttle that changes the width of the impeller that is exposed to the air stream	• Simple design	• Feasible in some applications only
Operate fans in parallel: two or more fans in parallel instead of one large one	• High efficiencies across wide variations in system demand. • Redundancy to mitigate the risk of downtime because of failure or unexpected maintenance. • Two smaller fans are less expensive and offer better performance than one relatively large one. • Can be equipped with other flow controls to increase flexibility and reliability.	• Should only be used when the fans can operate in a low resistance almost in a free delivery condition.
Operate fans in series: using multiple fans in a push-pull arrangement	• Lower average duct pressure • Lower noise generation • Lower structural and electrical support requirements • Suited for systems with long ducts, • large pressure drops across system components, or high resistances	• Not suited for low resistance systems (see Figure 5.18)

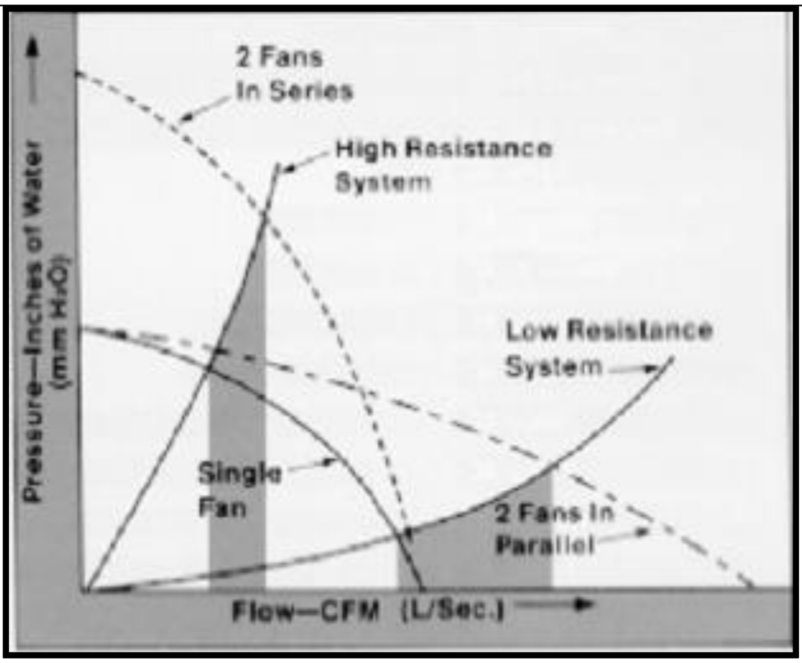


Figure 5.20 Fans Operating in Series and in Parallel (Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

5.5 Option Checklist

This section lists the most important energy efficiency options.

- Use smooth, well-rounded air inlet cones for fan air intake
- Avoid poor flow distribution at the fan inlet
- Minimize fan inlet and outlet obstructions
- Clean screens, filters and fan blades regularly
- Minimize fan speed
- Use low slip or flat belts for power transmission
- Check belt tension regularly
- Eliminate variable pitch pulleys
- Use variable speed drives for large variable fan loads
- Use energy-efficient motors for continuous or near continuous operation
- Eliminate leaks in duct works
- Minimize bends in duct works
- Turn fans and blowers off when not needed
- Reduce the fan speed by pulley diameter modifications in case of oversized motors
- Adopt inlet guide vanes in place of discharge damper control
- Change metallic / Glass reinforced plastic (GRP) impeller by more energy efficient hollow FRP impeller with aerofoil design
- Try to operate the fan near its best operating point (BEP)
- Reduce transmission losses by using energy efficient flat belts or cogged raw-edged V- belts instead of conventional V-belt systems
- Minimizing system resistance and pressure drops by improving the duct system
- Ensure proper alignment between drive and driven system
- Ensure proper power supply quality to the motor drive
- Regularly check for vibration trend to predict any incipient failures like bearing damage, misalignments, unbalance, foundation looseness etc.

Energy Audit Situation Analysis :

Estimation of Fan Static Efficiency

A V-belt driven centrifugal fan is supplying air in a process plant. The performance test conducted by an energy auditor on the fan generated the following data:

- Ambient temperature:30°C
- Density of air at 0°C: 1.293 kg/m^3
- Diameter of the discharge air duct: 0.8 m
- Velocity pressure measured by Pitot tube in discharge duct: 45 mmWC
- Pitot tube coefficient: 0.9
- Static pressure at fan inlet: - 20 mmWC
- Static pressure at fan outlet: 185 mmWC
- Power drawn by the motor coupled with the fan: 70 kW
- Belt transmission efficiency: 96%
- Motor efficiency at the operating load: 90%

The energy auditor concludes after analyzing the above data that the static efficiency of the fan is about 33.3%. Do you agree with his above observation? If not, can you find the mistake made by the auditor?

Corrected gas density = (273 x 1.293) / (273 + 30) = 1.165

Air velocity $= \frac{0.9\times\sqrt{2\times 9.81\times\Delta\rho\times\Upsilon}}{\Upsilon}$

=0.9 x Sq rt.(2 x 9.81 x 45 x 1.165)
1.165
=24.776 m/s
Area of the discharge duct: 3.14 x 0.8 x 0.8 x ¼ = 0.502672 m^2
Volume =24.776 x 0.502672 = 12.4543 m^3/s
Power input to the fan shaft = 70 x 0.96 x 0.90 = 60.48 kW

Fan static Efficiency $= \frac{12.4543\times(185-(-20))}{102\times 60.48}$
$= 41\%$

Now, the fan static efficiency is 41%. The auditor, while working out the total static pressure has committed a mistake. He has taken suction pressure as positive.

Fan static Efficiency $= \frac{12.4543\times(185-(-20))}{102\times 60.48}$
$= 33.3\%$

Two Fans in Parallel Operation

Two FD fans, one fan on each side of the Boiler, are supplying the total combustion air requirement for a boiler. These fans are connected to a common header through discharge dampers. Each fan is having 260 kW rating and provided with VSDs. Each fan is designed to cater 60% of Boiler capacity (MCR).

It was observed by an energy auditor that when one FD fan was in service (when the boiler requirement is below 60% MCR), power drawn by that fan is 105 kW at 570 rpm whereas the total power drawn by keeping both the fans in service for the same steam generation (below 60% MCR) is around 70 kW only (each fan is drawing 35 kW at 430 rpm). What could be the reasons for low power consumption with both fans in service than a single fan for generation of same quantity of steam?

Answer:

When one fan was in service, as it was a common discharge header system the possibility of recirculation of part of air from the running fan cannot be ruled out due to passing of discharge dampers and inlet vane of the fan that is not in service. This increases the air requirement for maintaining the same excess oxygen conditions, hence increase in load on the running fan.

Second reason can be that when only one fan is in service as airflow is from one side only, increases the system resistance than when same air is distributed from both the sides. This forces the single fan to develop more head for the same total airflow, hence operation at higher RPM. With both fans in service the system resistance will be low distributed flow.
Because of the above reasons there is a net saving of energy when both fans are in service than single fan.

5.6 References

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Chapter 6 Pumps and Pumping Systems

6.1 Introduction

This section briefly describes the main features of pumps and pumping systems.[1]

6.1.1 What are pumps and pumping systems?

Pumping systems account for nearly 20% of the world's electrical energy demand and range from 25-50% of the energy usage in certain industrial plant operations (US DOE, 2004).

Pumps have two main purposes:

- Transfer of liquid from one place to another place (e.g. water from an underground aquifer into a water storage tank)
- Circulate liquid around a system (e.g. cooling water or lubricants through machines and equipment)

The main components of a pumping system are:

- Pumps (different types of pumps are explained in section 2)
- Prime movers: electric motors, diesel engines or air system
- Piping, used to carry the fluid
- Valves, used to control the flow in the system
- Other fittings, controls and instrumentation
- End-use equipment, which have different requirements (e.g. pressure, flow) and therefore determine the pumping system components and configuration.

Figure 6.1 Pumping System in an Industry (US DOE, 2001)

Examples include heat exchangers, tanks and hydraulic machines.

The pump and the prime mover are typically the most energy inefficient components.

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[1] Information was sourced from three US DOE publications: *Improving Pumping System Performance – a Sourcebook for Industry* (1999); *Pump Life Cycle Costs – A Guide to LCC Analysis for Pumping Systems* (2001); and *Variable Speed Pumping – A Guide to Successful Applications* (2004). These publications are recommended for further reading.

6.1.2 Pumping system characteristics

6.1.2.1 Resistance of the system: head

Pressure is needed to pump the liquid through the system at a certain rate. This pressure has to be high enough to overcome the resistance of the system, which is also called “head”. The total head is the sum of static head and friction head:

a) Static head

Static head is the difference in height between the source and destination of the pumped liquid (see Figure 6.2a). Static head is independent of flow (see Figure 6.2b). The static head at a certain pressure depends on the weight of the liquid and can be calculated with this equation:

$$\text{Head (in feet)} = \frac{\text{Pressure (psi) X 2.31}}{\text{Specific gravity}}$$

Static head consists of:

- Static suction head (hS): resulting from lifting the liquid relative to the pump center line. The hS is positive if the liquid level is above pump centerline, and negative if the liquid level is below pump centerline (also called “suction lift)
- Static discharge head (hd): the vertical distance between the pump centerline and the surface of the liquid in the destination tank.

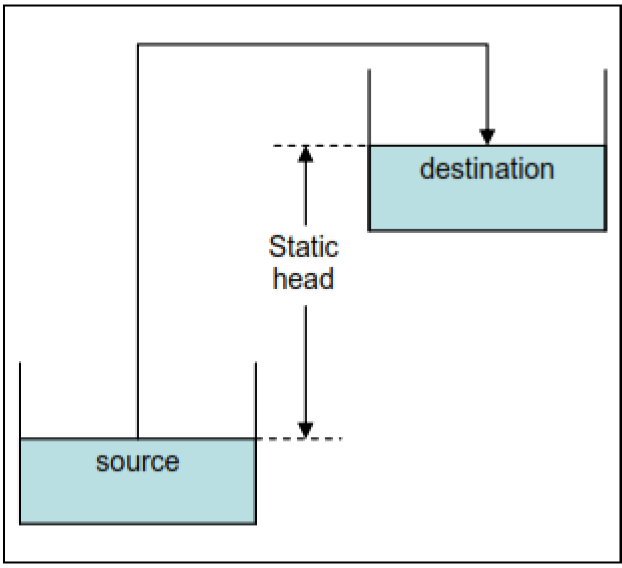

Figure 6.2a: Static Head

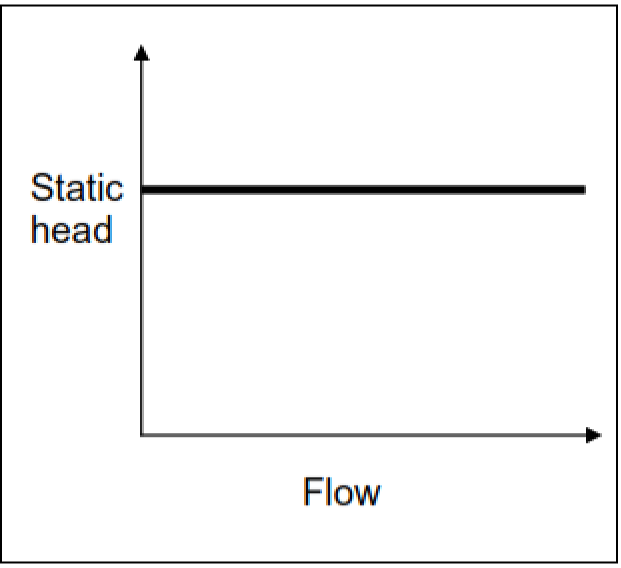

Figure 6.2b: Static head vs flow

b) Friction head (hf)

This is the loss needed to overcome that is caused by the resistance to flow in the pipe and fittings. It is dependent on size, condition and type of pipe, number and type of pipe fittings, flow rate, and nature of the liquid. The friction head is proportional to the square of the flow rate as shown in figure 6.3. A closed loop circulating system only exhibits friction head (i.e. not static head).

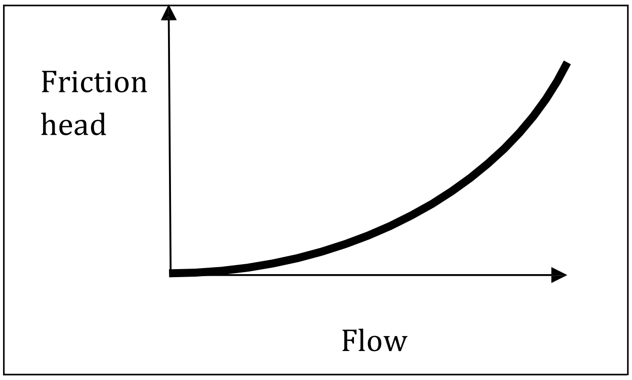

Figure 6.3. Frictional Head versus Flow

In most cases the total head of a system is a combination of static head and friction head as shown in Figures 6.4a and 6.4b.

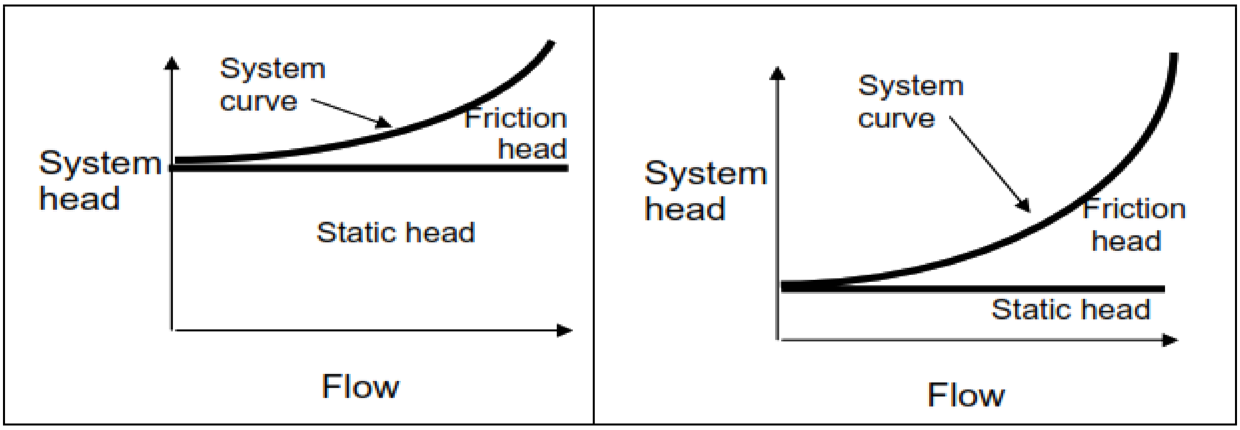

Figure 6.4a: System with high static head

Figure 6.4b: figure with low static head

6.1.2.2 Pump performance curve

The head and flow rate determine the performance of a pump, which is graphically shown in Figure 5 as the performance curve or pump characteristic curve. The figure shows a typical curve of a centrifugal pump where the head gradually decreases with increasing flow.

As the resistance of a system increases, the head will also increase. This in turn causes the flow rate to decrease and will eventually reach zero. A zero flow rate is only acceptable for a short period without causing to the pump to burn out.

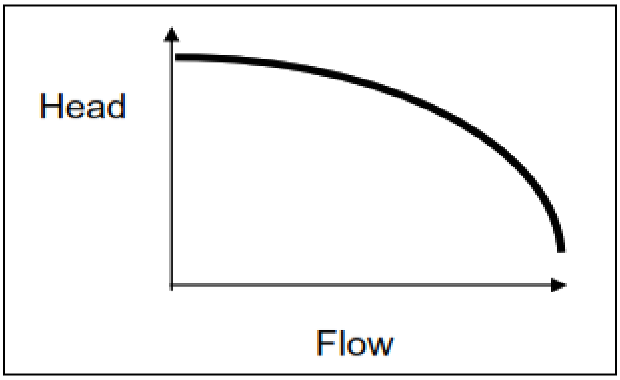

Figure 6.5: Performance curve of a pump

6.1.2.3 Pump operating point

The rate of flow at a certain head is called the duty point. The pump performance curve is made up of many duty points. The pump operating point is determined by the intersection of the system curve and the pump curve as shown in Figure 6.6.

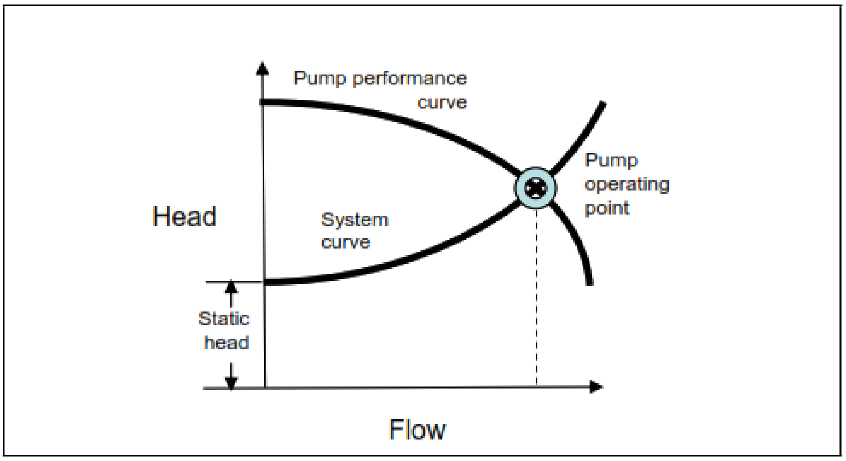

Figure 6.6: Pump operating point (US DOE, 2001)

6.1.2.4 Pump suction performance (NPSH)

Cavitation or vaporization is the formation of bubbles inside the pump. This may occur when at the fluid's local static pressure becomes lower than the liquid's vapor pressure (at the actual temperature). A possible cause is when the fluid accelerates in a control valve or around a pump impeller.

Vaporization itself does not cause any damage. However, when the velocity is decreased and pressure increased, the vapor will evaporate and collapse. This has three undesirable effects:

- Erosion of vane surfaces, especially when pumping water-based liquids
- Increase of noise and vibration, resulting in shorter seal and bearing life
- Partially choking of the impeller passages, reduces the pump performance and can lead to loss of total head in extreme cases.

The Net Positive Suction Head Available (NPSHA) indicates how much the pump suction exceeds the liquid vapor pressure, and is a characteristic of the system design. The NPSH Required (NPSHR) is the pump suction needed to avoid cavitation, and is a characteristic of the pump design.

6.2 Type of Pumps

This section describes the various types of pumps.[2] Pumps come in a variety of sizes for a wide range of applications. They can be classified according to their basic operating principle as dynamic or positive displacement pumps (Figure 6.7).

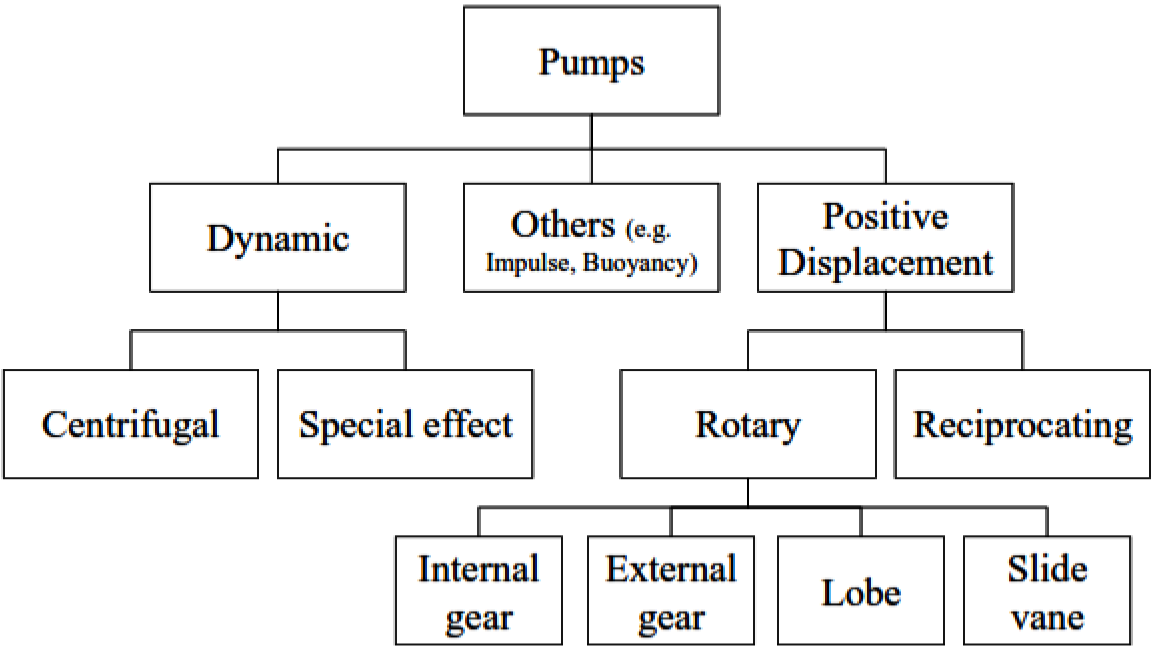

Figure 6.7: Types of pumps

In principle, any liquid can be handled by any of the pump designs. Where different pump designs could be used, the centrifugal pump is generally the most economical followed by rotary and reciprocating pumps. Although, positive displacement pumps are generally more efficient than centrifugal pumps, the benefit of higher efficiency tends to be offset by increased maintenance costs.

6.2.1 Positive displacement pumps

Positive displacement pumps are distinguished by the way they operate: liquid is taken from one end and positively discharged at the other end for every revolution. Positive displacement pumps are widely used for pumping fluids other than water, mostly viscous fluids.

Positive displacement pumps are further classified based upon the mode of displacement:

- ***Reciprocating pump*** if the displacement is by reciprocation of a piston plunger. Reciprocating pumps are used only for pumping viscous liquids and oil wells.
- ***Rotary pumps*** if the displacement is by rotary action of a gear, cam or vanes in a chamber of diaphragm in a fixed casing. Rotary pumps are further classified such as internal gear, external gear, lobe and slide vane etc. These pumps are used for special services with particular conditions existing in industrial sites.

In all positive displacement type pumps, a fixed quantity of liquid is pumped after each revolution. So if the delivery pipe is blocked, the pressure rises to a very high value, which can damage the pump.

6.2.2 Dynamic pumps

Dynamic pumps are also characterized by their mode of operation: a rotating impeller converts kinetic energy into pressure or velocity that is needed to pump the fluid.

There are two types of dynamic pumps:

- ***Centrifugal pumps*** are the most common pumps used for pumping water in industrial applications. Typically, more than 75% of the pumps installed in an industry are centrifugal pumps. For this reason, this pump is further described below.

- ***Special effect pumps*** are particularly used for specialized conditions at an industrial site.

6.2.2.1 How a centrifugal pump works

A centrifugal pump is one of the simplest pieces of equipment in any process plant. Figure 6.8 shows how this type of pump operates:

- Liquid is forced into an impeller either by atmospheric pressure, or in case of a jet pump by artificial pressure.
- The vanes of impeller pass kinetic energy to the liquid, thereby causing the liquid to rotate. The liquid leaves the impeller at high velocity. The impeller is surrounded by a volute casing or in case of a turbine pumps a stationary diffuser ring. The volute or stationary diffuser ring converts the kinetic energy into pressure energy.

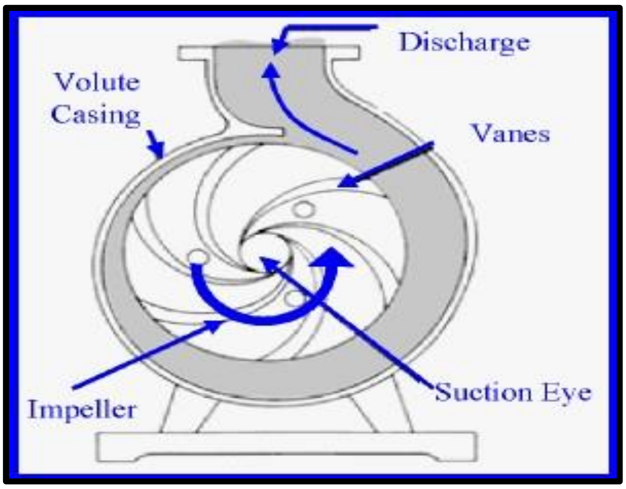

Figure 6.8 Liquid Flow Path of a Centrifugal Pump (Sahdev M)

6.2.2.2 Components of a centrifugal pump

The main components of a centrifugal pump are shown in Figure 6.9 and described below:

- Rotating components: an impeller coupled to a shaft
- Stationary components: casing, casing cover, and bearings.

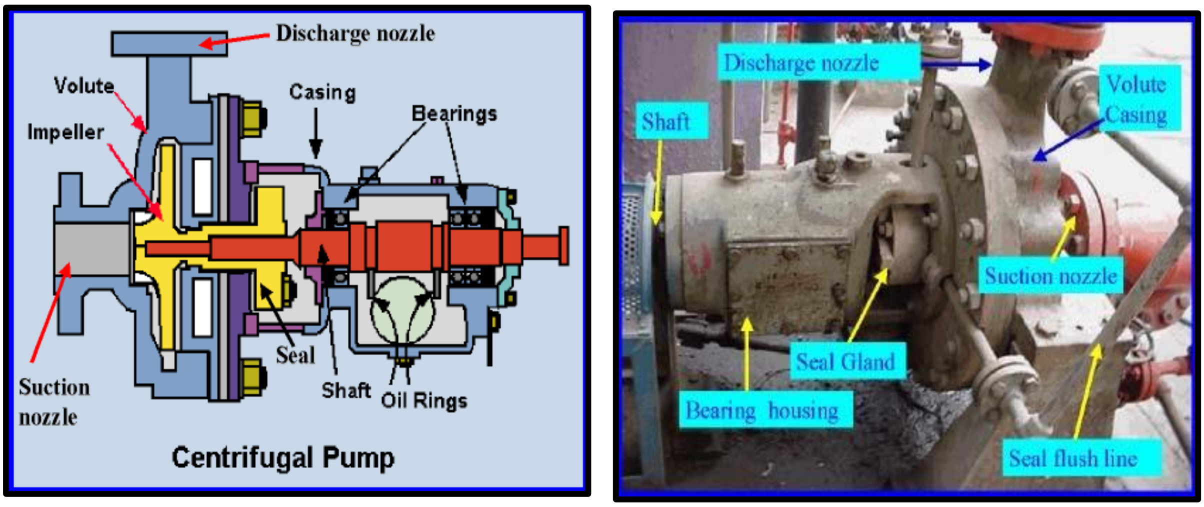

Figure 6.9. Main Components of a Centrifugal Pump (Sahdev)

a) Impeller

An impeller is a circular metallic disc with a built-in passage for the flow of fluid. Impellers are generally made of bronze, polycarbonate, cast iron or stainless steel, but other materials are also used. As the performance of the pump depends on the type of impeller, it is important to select a suitable design and to maintain the impeller in good condition.

The number of impellers determines the number of stages of the pump. A single stage pump has one impeller and is best suited for low head (= pressure) service. A two-stage pump has two impellers in series for medium head service. A multi-stage pump has three or more impellers in series for high head service.

Impellers can be classified on the basis of:

- ***Major direction of flow*** from the rotation axis: radial flow, axial flow, mixed flow
- ***Suction type***: single suction and double suction
- ***Shape or mechanical construction:***

  - Closed impellers have vanes enclosed by shrouds (= covers) on both sides (Figure 6.10).

  They are generally used for water pumps as the vanes totally enclose the water. This prevents the water from moving from the delivery side to the suction side, which would reduce the pump efficiency. In order to separate the discharge chamber from the suction chamber, a running joint is necessary between the impeller and pump casing. This joint is provided by wearing rings, which are mounted either over extended portion of impeller shroud or inside the cylindrical surface of pump casing. A disadvantage of closed impellers is the higher risk of blockage.

  - Open and semi-open impellers (Figure 10) are less likely to clog. But to avoid clogging through internal re-circulation, the volute or back-plate of the pump must be manually adjusted to get the proper impeller setting.
  - Vortex pump impellers are suitable for solid and "stringy" materials but they are up to 50% less efficient than conventional designs.

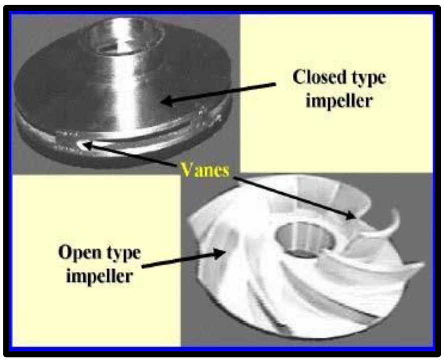

Figure 6.10 Closed and Open Impeller Types (Sahdev)

b) Shaft

The shaft transfers the torque from the motor to the impeller during the startup and operation of the pump.

c) Casing

The main function of casing is to enclose the impeller at suction and delivery ends and thereby form a pressure vessel. The pressure at suction end may be as little as one-tenth of atmospheric pressure and at delivery end may be twenty times the atmospheric pressure in a single-stage pump. For multi-stage pumps the pressure difference is much higher. The casing is designed to withstand at least twice this pressure to ensure a large enough safety margin.

A second function of casing is to provide a supporting and bearing medium for the shaft and impeller. Therefore the pump casing should be designed to

- Provide easy access to all parts of pump for inspection, maintenance and repair
- Make the casing leak-proof by providing stuffing boxes
- Connect the suction and delivery pipes directly to the flanges
- Be coupled easily to its prime mover (i.e. electric motor) without any power loss.

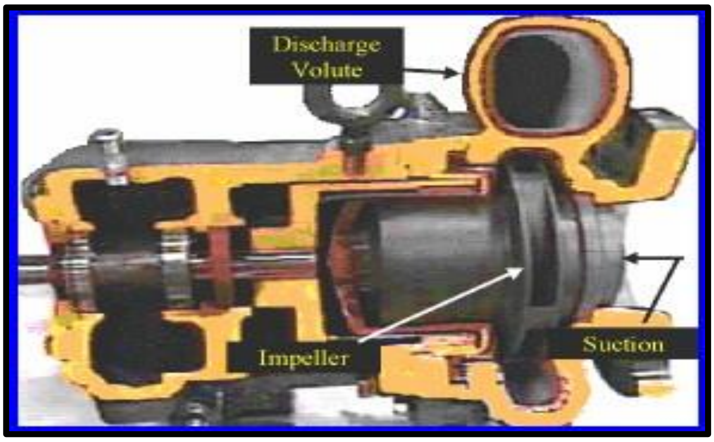

Figure 6.11. Cut-away of a pump showing casing volute

Figure 6.12. Solid Casing (Sahdev)

There are two types of casings

- ***Volute casing*** (Figure 6.11) has impellers that are fitted inside the casings. One of the main purposes is to help balance the hydraulic pressure on the shaft of the pump. However, operating pumps with volute casings at a lower capacity than the manufacturer's recommended capacity, can result in lateral stress on the shaft of the pump. This can cause increased wearing of the seals, bearings, and the shaft itself. Double-volute casings are used when the radial force becomes significant at reduced capacities.
- ***Circular casing*** has stationary diffusion vanes surrounding the impeller periphery that convert speed into pressure energy. These casings are mostly used for multi-stage pumps. The casings can be designed as:
    - ***Solid casing*** (Figure 6.12): the entire casing and the discharge nozzle are contained in one casting or fabricated piece.
    - ***Split casing:*** two or more parts are joined together. When the casing parts are divided by horizontal plane, the casing is called horizontally split or axially split casing.

6.3 Assessment of Pumps

This section explains how the performance of pumps and pumping systems can be assessed.[3]

6.3.1 How to calculate pump performance

The work performed by a pump is a function of the total head and of the weight of the liquid pumped in a given time period. Pump shaft power (Ps) is the actual horsepower delivered to the pump shaft, and can be calculated as follows:

Pump shaft power Ps = Hydraulic power hp / Pump efficiency η_{pump}

or

Pump efficiency η_{pump} = Hydraulic power / Pump shaft power

Pump output, water horsepower or hydraulic horsepower (hp) is the liquid horsepower delivered by the pump, and can be calculated as follows:

Hydraulic power hp = Q (m^3/s) x (h_d - h_s in m) x ρ (kg/m^3) x g (m/s^2) / 1000

Where:

Q = flow rate
h_d = discharge head h_s =
suction head
ρ = density of the fluid
g = acceleration due to gravity

Example:

In an industry, a centrifugal pump is pumping 80 m^3/hr of water into a container. The discharge head of the pump is 5 kg/cm^2(g) and water level is 5 meters below the pump central line. If the power drawn by the motor is 22 kW, find out the pump efficiency. Assume motor efficiency as 90% and the water density as 1000 kg/m^3.

Hydraulic Power (kW)= (mxgxh)/1000
Now m (kg/sec) =(80/3600)x 1000 kg/m3 (density)
g (m/s2)= 9.81
h(metre)= 50-(-5)= 55
(mxgxh) = 11,990 m2.kg/s3 (Joules/sec, as 1 Joule=m2.kg/s2)
= 11990 Watts (as 1 J/sec=1 Watt)
Hydraulic Power= (mxgxh)/1000 = 11.99 kW
Pump Efficiency= Hydraulic Power/(Motor output)
= Hydraulic Power/ (Motor input x efficiency)
= 11.99/ (22x0.9)
= 11.99/19.8
= 60.5%

6.3.2 Difficulties in the assessment of pumps

In practice, it is more difficult to assess pump performance. Some important reasons are:

- ***Absence of pump specification data***: Pump specification data are required to assess the pump performance. Most companies do not keep original equipment manufacturer (OEM) documents that provide these data. In these cases, the percentage pump loading for a pump flow or head cannot be estimated satisfactorily.
- ***Difficulty in flow measurement***: It is difficult to measure the actual flow. The methods are used to estimate the flow. In most cases the flow rate is calculated based on type of fluid, head and pipe size etc. but the calculated figure may not be accurate. Another method is to divide the tank volume by the time it takes for the pump to fill the tank. This method can, however, only be applied if one pump is in operation and if the discharge valve of the tank is closed. The most sophisticated, accurate and least time consuming way to measure the pump flow is by measurement with an ultrasonic flow meter.
- ***Improper calibration of pressure gauges and measuring instruments***: Proper calibration of all pressure gauges at suction and discharge lines and other power measuring instruments is important to obtain accurate measurements. But calibration has not always been carried out. Sometimes correction factors are used when gauges and instruments are not properly calibrated. Both will lead to incorrect performance assessment of pumps.

6.4 Energy Efficiency Opportunities

This section includes main areas for improving pumps and pumping systems. The main areas for energy conservation include:

- Selecting the right pump
- Controlling the flow rate by speed variation
- Pumps in parallel to meet varying demand
- Eliminating flow control valve
- Eliminating by-pass control
- Start/stop control of pump
- Impeller trimming

6.4.1 Selecting the right pump 4

In selecting the pump, suppliers try to match the system curve supplied by the user with a pump curve that satisfies these needs as closely as possible. The pump operating point is the point where the pump curve and the system resistance curve intersect (as explained in section6.1.2.3). However, it is impossible for one operating point to meet all desired operating conditions. For example, when the discharge valve is throttled, the system resistance curve shifts to the left and so does the operating point (see Figure 6.13). Figure 6.13 below shows a typical vendor-supplied pump performance curves for a centrifugal pump where clear water is the pumping liquid.

The Best Efficiency Point (BEP) is the pumping capacity at maximum impeller diameter, in other words, at which the efficiency of the pump is highest. All points to the right or left of the BEP have a lower efficiency. The BEP is affected when the selected pump is oversized. The reason is that the flow of oversized pumps must be controlled with different methods, such as a throttle valve or a by-pass line. These provide additional resistance by increasing the friction. As a result the system curve shifts to the left and intersects the pump curve at another point. The BEP is now also lower. In other words, the pump efficiency is reduced because the output flow is reduced but power consumption is not. Inefficiencies of oversized pumps can be overcome by, for example, the installation of VSDs, two-speed drives, lower rpm motors, smaller impeller or trimmed impeller (Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers).

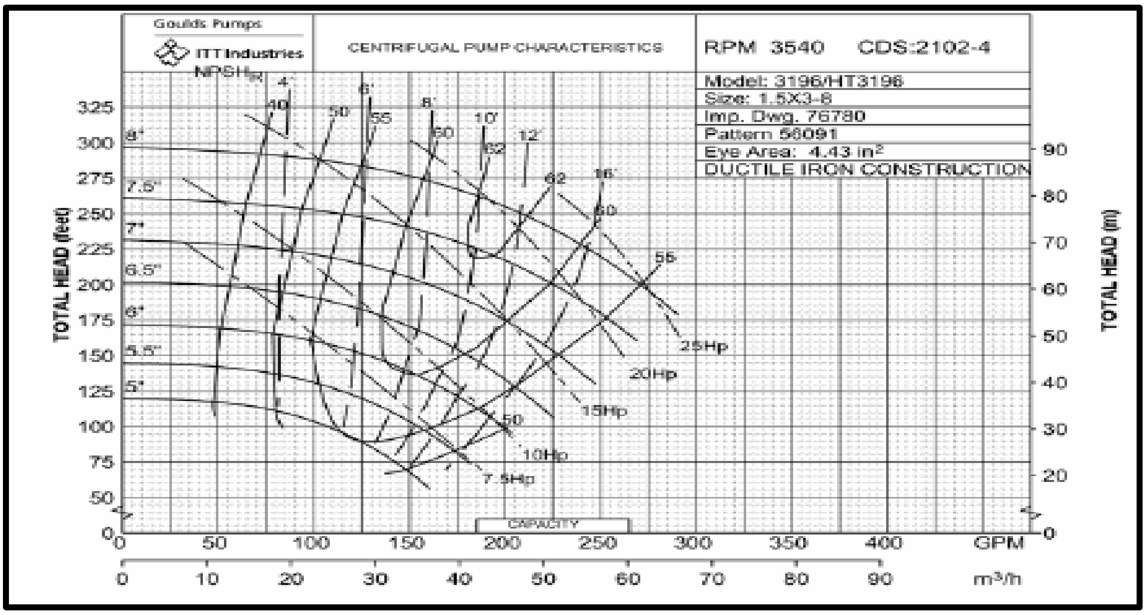

Figure 6.12: Typical centrifugal pump performance curve given by suppliers
(Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

6.4.2 Controlling flow rate by speed variation

6.4.2.1 Explaining the effect of speed5

A centrifugal pump's rotating impeller generates head. The impeller's peripheral velocity is directly related to shaft rotational speed. Therefore varying the rotational speed has a direct effect on the performance of the pump.

The pump performance parameters (flow rate, head, power) will change with varying rotating speeds. To safely control a pump at different speeds it is therefore important to understand the relationships between the two. The equations that explain these relationships are known as the "Affinity Laws":

Flow rate (Q) is proportional to the rotating speed (N)
Head (H) is proportional to the square of the rotating speed (N)
Power (P) is proportional to the cube of the rotating speed (N)

$$Q \propto N$$
$$Q \propto N^2$$
$$Q \propto N^3$$

As can be seen from the above laws, doubling the rotating speed of the centrifugal pump will increase the power consumption by 8 times. Conversely a small reduction in speed will result in a very large reduction in power consumption. This forms the basis for energy conservation in centrifugal pumps with varying flow requirements.

It is relevant to note that flow control by speed regulation is always more efficient than by a control valve. This is because valves reduce the flow, but not the energy consumed by pumps. In addition to energy savings, there could be other benefits of lower speeds.

- Bearings life is increased. This is because bearings carry the hydraulic forces on the impeller (created by the pressure profile inside the pump casing), which are reduced approximately with the square of speed. For a pump, bearing life is proportional to the seventh power of speed (N^7)!
- Vibration and noise are reduced and seal life is increased, provided that the duty point remains within the allowable operating range.

6.4.2.2 Using variable speed drive (VSD)

As explained earlier, controlling the pump speed is the most efficient way to control the flow, because when the pump's speed is reduced, the power consumption is also reduced. The most commonly used method to reduce pump speed is Variable Speed Drive (VSD).

VSDs allow pump speed adjustments over a continuous range, avoiding the need to jump from speed to speed as with multiple-speed pumps. VSDs control pump speeds use two types of systems:

- Mechanical VSDs include hydraulic clutches, fluid couplings, and adjustable belts and pulleys.
- Electrical VSDs include eddy current clutches, wound-rotor motor controllers, and variable frequency drives (VFDs). VFDs are the most popular and adjust the electrical frequency of the power supplied to a motor to change the motor's rotational speed.

For many systems, VFDs offer a means to improve the pump operating efficiency under different operating conditions. The effect of slowing pump speed on the pump operation is illustrated in Figure 6.14. When a VFD reduced the RPM of a pump, the head/flow and power curves move down and to the left, and the efficiency curve also shifts to the left.

The major advantages of VSD application in addition to energy saving are (US DOE, 2004):

- Improved process control because VSDs can correct small variations in flow more quickly.
- Improved system reliability because wear of pumps, bearings and seals is reduced.
- Reduction of capital & maintenance cost because control valves, by-pass lines, and conventional starters are no longer needed.
- Soft starter capability: VSDs allow the motor the motor to have a lower startup current.

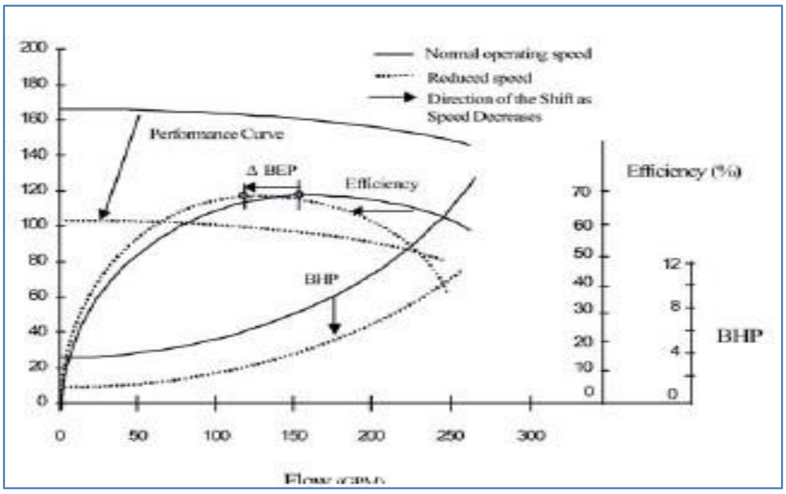

Figure 6.13. Effect of VFD (US DOE, 2004)

6.4.3 Pumps in parallel to meet varying demand

Operating two pumps in parallel and turning one of when the demand is lower, can result in significant energy savings. Pumps providing different flow rates can be used. Parallel pumps are an option when the static head is more than fifty percent of the total head. Figure 6.15 shows the pump curve for a single pump, two pumps operating in parallel and three pumps operating in parallel. It also shows that the system curve normally does not change by running pumps in parallel. The flow rate is lower than the sum of the flow rates of the different pumps.

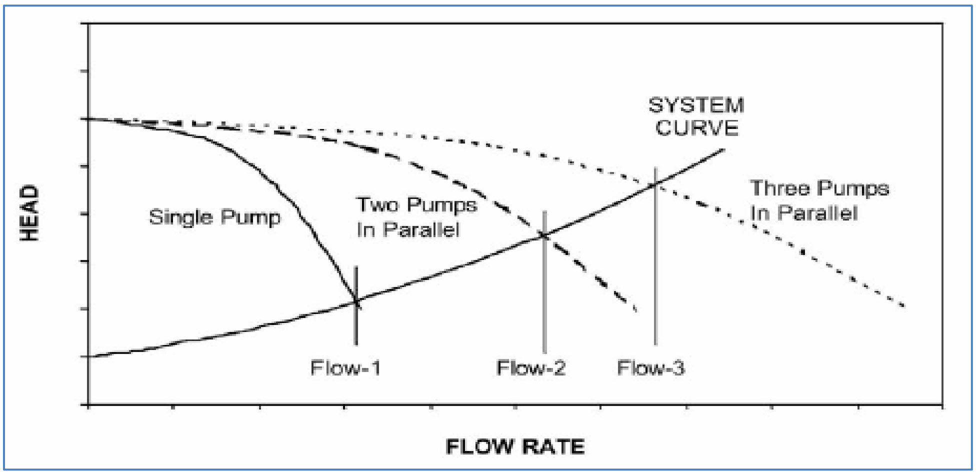

Figure 6.14. Typical performance curves for pumps in parallel (BPMA)

6.4.4 Eliminating flow control valve

Another method to control the flow by closing or opening the discharge valve (this is also known as “throttling” the valves). While this method reduces the flow, it does not reduce the power consumed, as the total head (static head) increases. Figure 6.16 shows how the system curve moves upwards and to the left when a discharge valve is half closed.

This method increases vibration and corrosion and thereby increases maintenance costs of pumps and potentially reduces their lifetimes. VSDs are a better solution from an energy efficiency perspective.

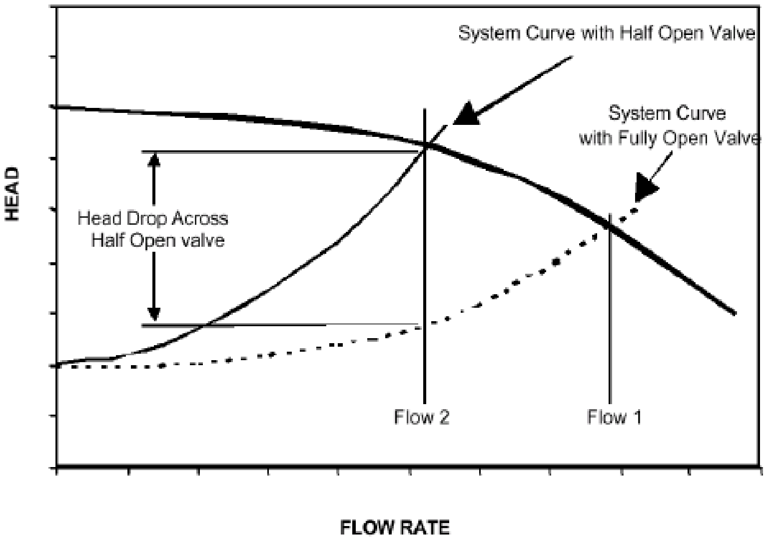

Figure 6.15. Control of Pump Flow by Valve (BPMA)

6.4.5 Eliminating by-pass control

The flow can also be reduced by installing a by-pass control system, in which the discharge of the pump is divided into two flows going into two separate pipelines. One of the pipelines delivers the fluid to the delivery point, while the second pipeline returns the fluid to the source. In other words, part of the fluid is pumped around for no reason, and thus is an energy wastage. This option should therefore be avoided.

6.4.6 Start/stop control of pump

A simple and reasonable energy efficient way to reduce the flow rate is by starting and stopping the pump, provided that this does not happen too frequently. An example where this option can be applied, is when a pump is used to fill a storage tank from which the fluid flows to the process at a steady rate. In this system, controllers are installed at the minimum and maximum level inside the tank to start and stop the pump. Some companies use this method also to avoid lower the maximum demand (i.e. by pumping at non-peak hours).

6.4.7 Impeller trimming

Changing the impeller diameter gives a proportional change in the impeller’s peripheral velocity. Similar to the affinity laws, the following equations apply to the impeller diameter D:

$$Q \propto D$$
$$Q \propto D^2$$
$$Q \propto D^3$$

Changing the impeller diameter is an energy efficient way to control the pump flow rate. However, for this option, the following should be considered:

- This option cannot be used where varying flow patterns exist.
- The impeller should not be trimmed more than 25% of the original impeller size, otherwise it leads to vibration due to cavitation and therefore decrease the pump efficiency.

- The balance of the pump has to be maintained, i.e. the impeller trimming should be the same on all sides.

Changing the impeller itself is a better option than trimming the impeller, but is also more expensive and sometimes the smaller impeller is too small. Figure 6.17 illustrates the effect of impeller diameter reduction on centrifugal pump performance.

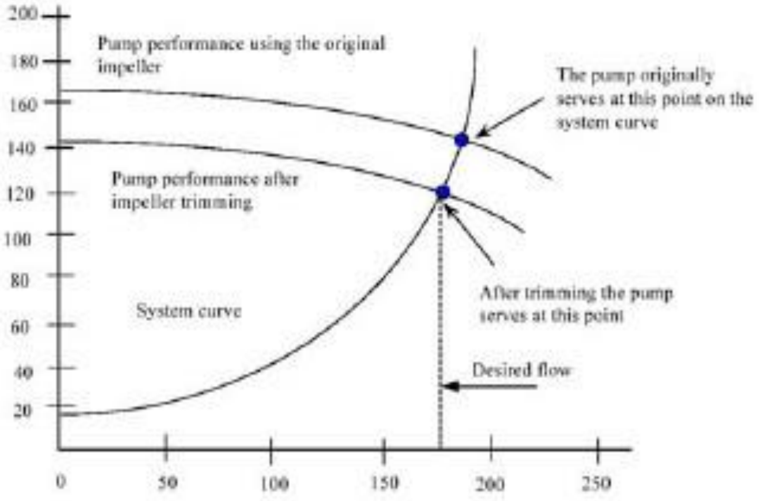

Figure 6.16. Impeller diameter reduction on centrifugal pump performance
(Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

A comparison of different energy conservation options in pumps and pumping system is summarized below.

Table 6.1 Comparison of different energy conservation options in pumps (adapted from US DOE 2001)

Parameter	Change control valve	Trim impeller	VFD
Impeller diameter	430 mm	375 mm	430 mm
Pump head	71.7 m	42 m	34.5 m
Pump efficiency	75.1%	72.1%	77%
Rate of flow	80 m^3/hr	80 m^3/hr	80 m^3/hr
Power consumed	23.1 kW	14 kW	11.6 kW

6.5 Option Checklist

This section includes most important options to improve energy efficiency of pumps and pumping systems.

- Operate pumps near their best efficiency point (BEP)
- Ensure adequate NPSH at site of installation
- Modify pumping system and pumps losses to minimize throttling.
- Ensure availability of basic instruments at pumps like pressure gauges, flow meters
- Adapt to wide load variation with variable speed drives or sequenced control of multiple units
- Avoid operating more than one pump for the same application
- Use booster pumps for small loads requiring higher pressures
- To improve the performance of heat exchangers, reduce the difference in temperature between the inlet and outlet rather than increasing the flow rate
- Repair seals and packing to minimize water loss by dripping
- Balance the system to minimize flows and reduce pump power requirements
- Avoid pumping head with a free-fall return (gravity), and use the siphon effect
- Conduct a water balance to minimize water consumption, thus optimum pump operation
- Avoid cooling water re-circulation in DG sets, air compressors, refrigeration systems, cooling towers feed water pumps, condenser pumps and process pumps
- In multiple pump operations, carefully combine the operation of pumps to avoid throttling
- Replace old pumps with energy efficient pumps
- To improve the efficiency of oversized pumps, install variable speed drive, downsize /replace impeller, or replace with a smaller pump
- Optimize the number of stages in multi-stage pump if margins in pressure exist
- Reduce the system resistance by pressure drop assessment and pipe size optimization
- Regularly check for vibration to predict bearing damage, misalignments, unbalance, foundation looseness etc.

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Chapter 7 Cooling Towers

7.1 Introduction

This section briefly describes the main features of cooling towers.

7.1.1 What is a cooling tower?

Cooled water is needed for, for example, air conditioners, manufacturing processes or power generation. A cooling tower is an equipment used to reduce the temperature of a water stream by extracting heat from water and emitting it to the atmosphere. Cooling towers make use of evaporation whereby some of the water is evaporated into a moving air stream and subsequently discharged into the atmosphere. As a result, the remainder of the water is cooled down significantly (Figure 7.1). Cooling towers are able to lower the water temperatures more than devices that use only air to reject heat, like the radiator in a car, and are therefore more cost-effective and energy efficient.

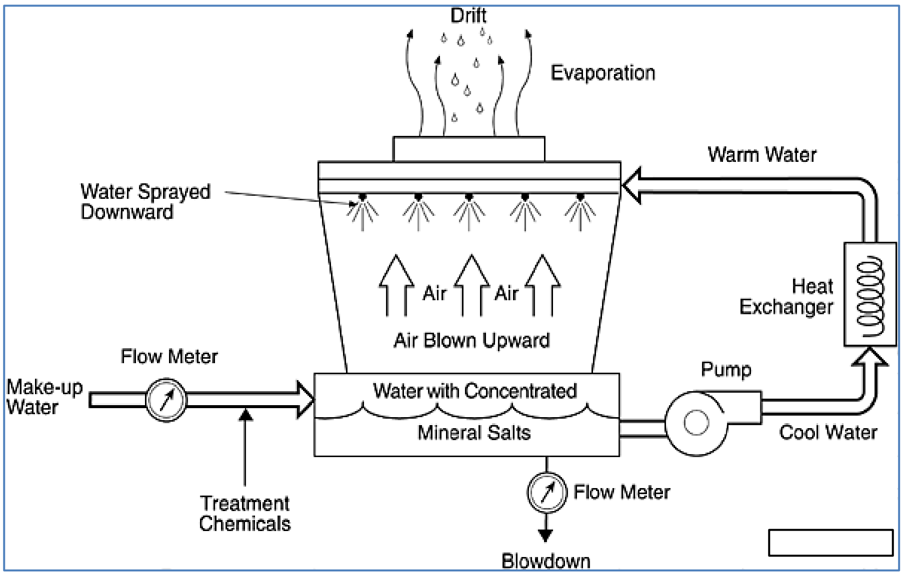

Figure 7.1. Schematic diagram of a cooling water system
(Pacific Northwest National Laboratory, 2001)

7.1.2 Components of a cooling tower

The basic components of a cooling tower include the frame and casing, fill, cold-water basin, drift eliminators, air inlet, louvers, nozzles and fans. These are described below.[1]

- ***Frame and casing.*** Most towers have structural frames that support the exterior enclosures (casings), motors, fans, and other components. With some smaller designs, such as some glass fiber units, the casing may essentially be the frame.
- ***Fill.*** Most towers employ fills (made of plastic or wood) to facilitate heat transfer by maximizing water and air contact. There are two types of fill: Splash fill: water falls over successive layers of horizontal splash bars, continuously breaking into smaller droplets, while also wetting the fill surface. Plastic splash fills promote better heat transfer than wood splash fills. Film fill: consists

of thin, closely spaced plastic surfaces over which the water spreads, forming a thin film in contact with the air. These surfaces may be flat, corrugated, honeycombed, or other patterns. The film type of fill is the more efficient and provides same heat transfer in a smaller volume than the splash fill.

- ***Cold-water basin.*** The cold-water basin is located at or near the bottom of the tower, and it receives the cooled water that flows down through the tower and fill. The basin usually has a sump or low point for the cold-water discharge connection. In many tower designs, the cold- water basin is beneath the entire fill. In some forced draft counter flow design, however, the water at the bottom of the fill is channeled to a perimeter trough that functions as the cold- water basin. Propeller fans are mounted beneath the fill to blow the air up through the tower. With this design, the tower is mounted on legs, providing easy access to the fans and their motors.

- ***Drift eliminators.*** These capture water droplets entrapped in the air stream that otherwise would be lost to the atmosphere.

- ***Air inlet.*** This is the point of entry for the air entering a tower. The inlet may take up an entire side of a tower (cross-flow design) or be located low on the side or the bottom of the tower (counter-flow design).
- ***Louvers.*** Generally, cross-flow towers have inlet louvers. The purpose of louvers is to equalize air flow into the fill and retain the water within the tower. Many counter flow tower designs do not require louvers.

- ***Nozzles.*** These spray water to wet the fill. Uniform water distribution at the top of the fill is essential to achieve proper wetting of the entire fill surface. Nozzles can either be fixed and spray in a round or square patterns, or they can be part of a rotating assembly as found in some circular cross-section towers.

- ***Fans.*** Both axial (propeller type) and centrifugal fans are used in towers. Generally, propeller fans are used in induced draft towers and both propeller and centrifugal fans are found in forced draft towers. Depending upon their size, the type of propeller fans used is either fixed or variable pitch. A fan with non-automatic adjustable pitch blades can be used over a wide kW range because the fan can be adjusted to deliver the desired air flow at the lowest power consumption. Automatic variable pitch blades can vary air flow in response to changing load conditions.

7.1.3 Tower materials

Originally, cooling towers were constructed primarily with wood, including the frame, casing, louvers, fill and cold-water basin. Sometimes the cold-water basin was made of concrete. Today, manufacturers use a variety of materials to construct cooling towers. Materials are chosen to enhance corrosion resistance, reduce maintenance and promote reliability and long service life. Galvanized steel, various grades of stainless steel, glass fiber, and concrete are widely used in tower construction, as well as aluminum and plastics for some components 2.

- ***Frame and casing.*** Wooden towers are still available, but many components are made of different materials, such as the casing around the wooden framework of glass fiber, the inlet air louvers of glass fiber, the fill of plastic and the cold-water basin of steel. Many towers (casings and basins) are constructed of galvanized steel or, where a corrosive atmosphere is a problem, the tower and/or the basis are made of stainless steel. Larger towers sometimes are made of concrete. Glass fiber is also widely used for cooling tower casings and basins, because they extend the life of the cooling tower and provide protection against harmful chemicals.
- ***Fill.*** Plastics are widely used for fill, including PVC, polypropylene, and other polymers. When water conditions require the use of splash fill, treated wood splash fill is still used in wooden towers, but plastic splash fill is also widely used. Because of greater heat transfer efficiency, film fill is chosen for applications where the circulating water is generally free of debris that could block the fill passageways.
- ***Nozzles.*** Plastics are also widely used for nozzles. Many nozzles are made of PVC, ABS, polypropylene, and glass-filled nylon.
- ***Fans.*** Aluminum, glass fiber and hot-dipped galvanized steel are commonly used fan materials. Centrifugal fans are often fabricated from galvanized steel. Propeller fans are made from galvanized steel, aluminum, or molded glass fiber reinforced plastic.

7.2 Types of Cooling Towers

This section describes the two main types of cooling towers: the natural draft and mechanical draft cooling towers.

7.2.1 Natural draft cooling tower

The natural draft or hyperbolic cooling tower makes use of the difference in temperature between the ambient air and the hotter air inside the tower. As hot air moves upwards through the tower (because hot air rises), fresh cool air is drawn into the tower through an air inlet at the bottom. Due to the layout of the tower, no fan is required and there is almost no circulation of hot air that could affect the performance. Concrete is used for the tower shell with a height of up to 200 m. These cooling towers are mostly only for large heat duties because large concrete structures are expensive.

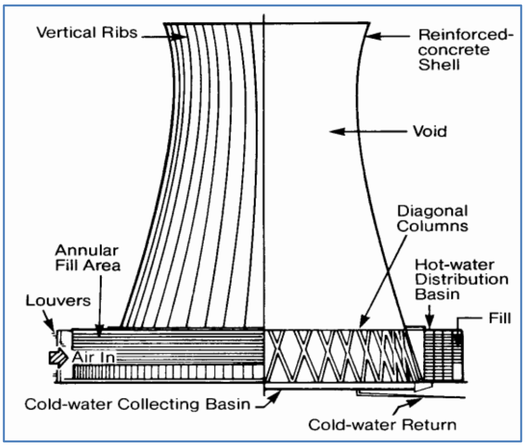

Figure 7.2. Cross flow natural draft cooling

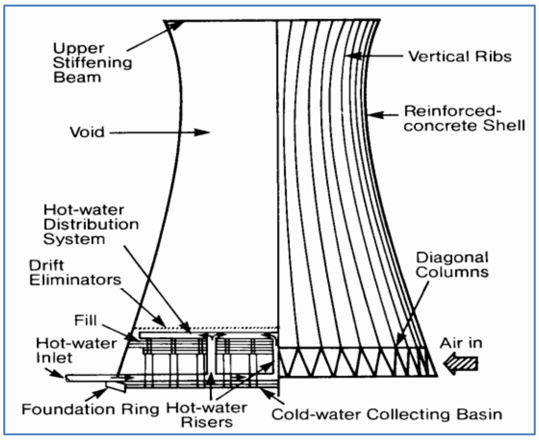

Figure 7.3. Counter flow natural draft cooling

(Gulf Coast Chemical Commercial Inc, 1995)

There are two main types of natural draft towers:

- Cross flow tower (Figure 7.2): air is drawn across the falling water and the fill is located outside the tower
- Counter flow tower (Figure 7.3): air is drawn up through the falling water and the fill is therefore located inside the tower, although design depends on specific site conditions

7.2.2 Mechanical draft cooling tower

Mechanical draft towers have large fans to force or draw air through circulated water. The water falls downwards over fill surfaces, which help increase the contact time between the water and the air - this helps maximize heat transfer between the two. Cooling rates of mechanical draft towers depend upon various parameters such as fan diameter and speed of operation, fills for system resistance etc. Mechanical draft towers are available in a large range of capacities. Towers can be either factory built or field erected – for example concrete towers are only field erected.

Many towers are constructed so that they can be grouped together to achieve the desired capacity. Thus, many cooling towers are assemblies of two or more individual cooling towers or “cells.” The number of cells they have, e.g., an eight-cell tower, often refers to such towers. Multiple-cell towers can be lineal, square, or round depending upon the shape of the individual cells and whether the air inlets are located on the sides or bottoms of the cells.

The three types of mechanical draft towers are summarized in Table 7.1.

Table 7.1 Main features of different types of draft cooling towers (based on AIRAH)

Type of cooling tower	Advantages	Disadvantages
Forced draft cooling tower (Figure 7.4): air is blown through the tower by a fan located in the air inlet	• Suited for high air resistance due to centrifugal blower fans • Fans are relatively quiet	• Recirculation due to high air-entry and low air-exit velocities, which can be solved by locating towers in plant rooms combined with discharge ducts
Induced draft cross flow cooling tower (Figure 7.5): • water enters at top and passes over fill • air enters on one side (single-flow tower) or opposite sides (double-flow tower)an induced draft fan	• Less recirculation than forced draft towers because the speed of exit air is 3-4 times higher than entering air	• Fans and the motor drive mechanism require weather-proofing against moisture and corrosion because they are in the path of humid exit air
Induced draft counter flow cooling tower (Figure 7.6): • hot water enters at the top • air enters bottom and exits at the top • uses forced and induced draft fans		

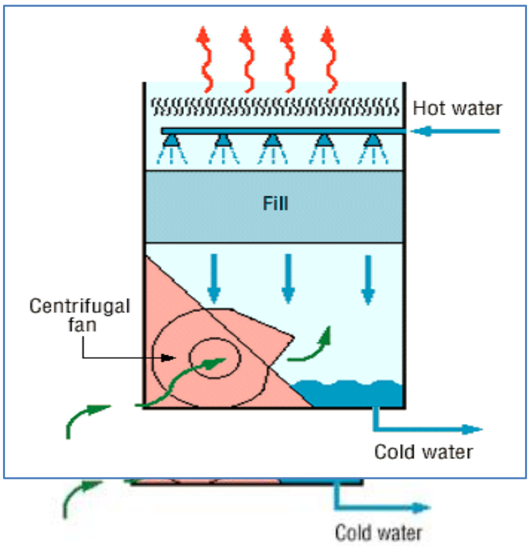

Figure 7.4. Forced Draft Cooling Tower ((GEO4VA))

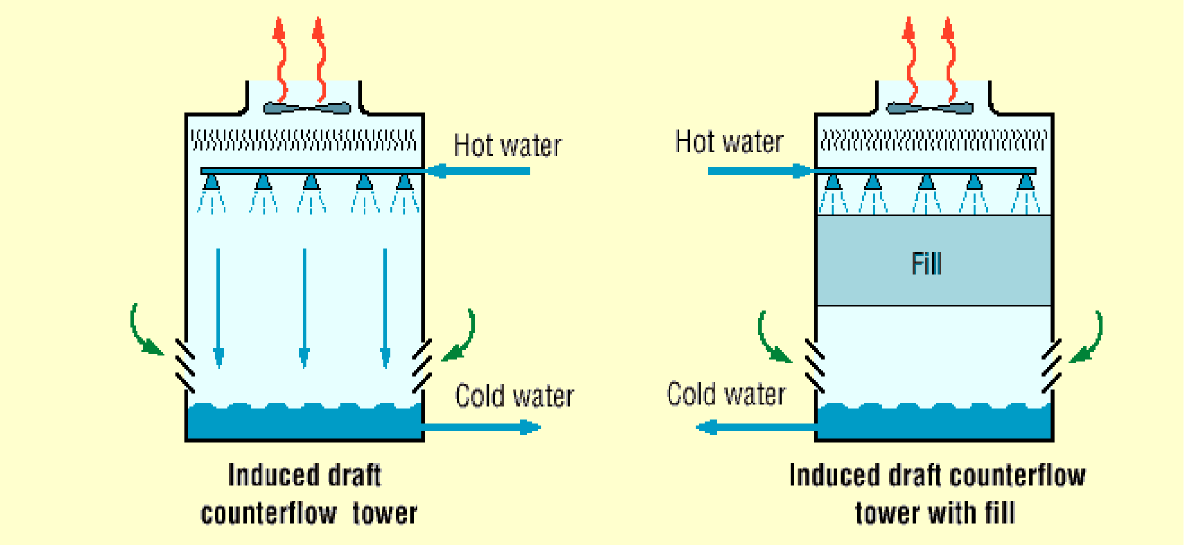

Figure 7.5. Induced draft counter flow cooling tower (GEO4VA)

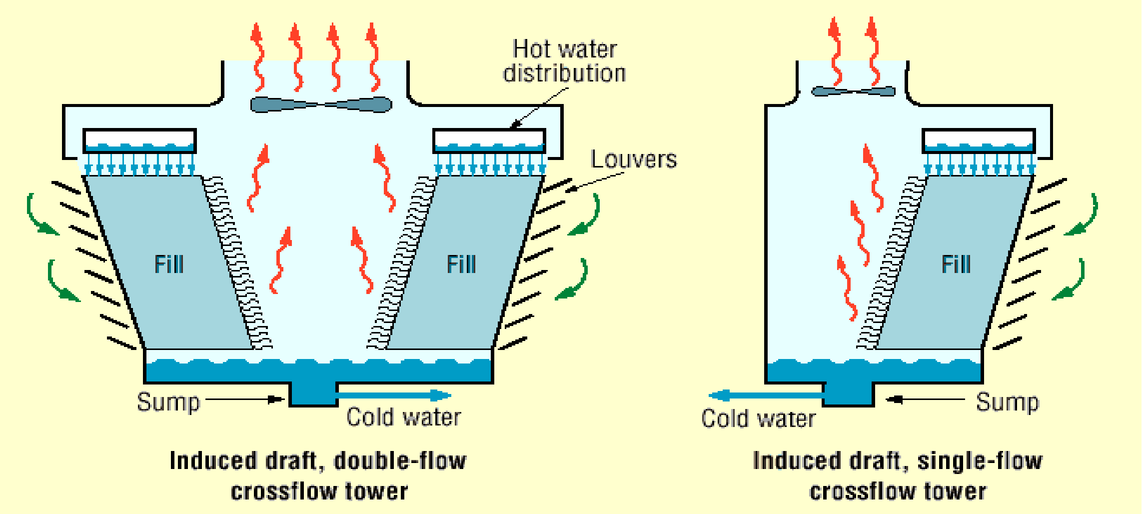

Figure 7.6. Induced draft cross flow cooling tower (GEO4VA)

7.3 Assessment of Cooling Towers

This section describes how the performance of cooling towers can be assessed.3 The performance of cooling towers is evaluated to assess present levels of approach and range against their design values, identify areas of energy wastage and to suggest improvements.

During the performance evaluation, portable monitoring instruments are used to measure the following parameters:

- Wet bulb temperature of air
- Dry bulb temperature of air
- Cooling tower inlet water temperature
- Cooling tower outlet water temperature
- Exhaust air temperature
- Electrical readings of pump and fan motors
- Water flow rate
- Air flow rate

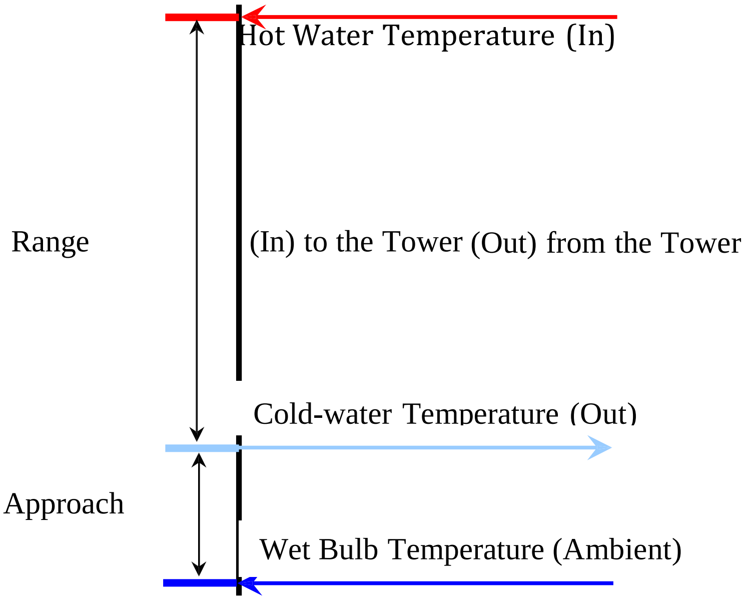

Figure 7. 7 Range and approach of cooling towers

These measured parameters and then used to determine the cooling tower performance in several ways. (Note: CT = cooling tower; CW = cooling water). These are:

a) ***Range*** (see Figure 7). This is the difference between the cooling tower water inlet and outlet temperature. A high CT Range means that the cooling tower has been able to reduce the water temperature effectively, and is thus performing well. The formula is:

CT Range (°C) = [CW inlet temp (°C) – CW outlet temp (°C)]

b) ***Approach*** (see Figure 7). This is the difference between the cooling tower outlet cold-water temperature and ambient wet bulb temperature. The lower the approach better is the cooling tower performance. Although, both range and approach should be monitored, the `Approach' is a better indicator of cooling tower performance.

CT Approach (°C) = [CW outlet temp (°C) – Wet bulb temp (°C)]

c) ***Effectiveness***. This is the ratio between the range and the ideal range (in percentage), i.e. difference between cooling water inlet temperature and ambient wet bulb temperature, or in other words it is = Range / (Range + Approach). The higher this ratio higher is the cooling tower effectiveness.

CT Effectiveness (%) = 100 x (CW temp – CW out temp) / (CW in temp – WB temp)

d) **Cooling capacity**. This is the heat rejected in kCal/hr or TR, given as product of mass flow rate of water, specific heat and temperature difference.

e) ***Evaporation loss***. This is the water quantity evaporated for cooling duty. Theoretically the evaporation quantity works out to 1.8 m^3 for every 1,000,000 kCal heat rejected. The following formula can be used (Perry):

Evaporation loss (m^3/hr) = 0.00085 x 1.8 x circulation rate (m^3/hr) x (T1-T2)
T1 - T2 = temperature difference between inlet and outlet water

f) ***Cycles of concentration*** (C.O.C). This is the ratio of dissolved solids in circulating water to the dissolved solids in make-up water.

g) ***Blow down losses*** depend upon cycles of concentration and the evaporation losses and is given by formula:

Blow down = Evaporation loss / (C.O.C. – 1)

h) ***Liquid/Gas (L/G) ratio***. The L/G ratio of a cooling tower is the ratio between the water and the air mass flow rates. Cooling towers have certain design values, but seasonal variations require adjustment and tuning of water and air flow rates to get the best cooling tower effectiveness. Adjustments can be made by water box loading changes or blade angle adjustments. Thermodynamic rules also dictate that the heat removed from the water must be equal to the heat absorbed by the surrounding air. Therefore the following formulae can be used:

$$L(T1 - T2) = G(h2 - h1)$$
$$L/G = (h2 - h1) / (T1 - T2)$$

Where:

L/G = liquid to gas mass flow ratio (kg/kg)
T1 = hot water temperature (^{0}C)
T2 = cold-water temperature (^{0}C)

h2 = enthalpy of air-water vapor mixture at exhaust wet-bulb temperature (same units as above)
h1 = enthalpy of air-water vapor mixture at inlet wet-bulb temperature (same units as above)

7.4 Energy Efficiency Opportunities

This section includes main areas for improving energy efficiency of cooling towers. The main areas for energy conservation include:

- Selecting the right cooling tower (because the structural aspects of the cooling tower cannot be changed after it is installed)

- Fills
- Pumps and water distribution system
- Fans and motors

7.4.1 Selecting the right cooling towers

Once a cooling tower is in place it is very difficult to significantly improve its energy performance. A number of factors are of influence on the cooling tower's performance and should be considered when choosing a cooling tower: capacity, range, approach, heat load, wet bulb temperature, and the relationship between these factors. This is described below.

7.4.1.1 Capacity

Heat dissipation (in kCal/hour) and circulated flow rate (m^3/hr) are an indication of the capacity of cooling towers. However, these design parameters are not sufficient to understand the cooling tower performance. For example, a cooling tower sized to cool 4540 m^3/hr through a 13.9°C range might be larger than a cooling tower to cool 4540 m^3/hr through 19.5°C range. Therefore other design parameters are also needed.

7.4.1.2 Range

Range is determined not by the cooling tower, but by the process it is serving. The range at the exchanger is determined entirely by the heat load and the water circulation rate through the exchanger and going to the cooling water. The range is a function of the heat load and the flow circulated through the system:

Range °C = Heat load (in kCal/hour) / Water circulation rate (l/hour)

Cooling towers are usually specified to cool a certain flow rate from one temperature to another temperature at a certain wet bulb temperature. For example, the cooling tower might be specified to cool 4540 m^3/hr from 48.9°C to 32.2°C at 26.7°C wet bulb temperature.

7.4.1.3 Approach

As a general rule, the closer the approach to the wet bulb, the more expensive the cooling tower due to increased size. Usually a 2.8°C approach to the design wet bulb is the coldest water temperature that cooling tower manufacturers will guarantee. When the size of the tower has to be chosen, then the approach is most important, closely followed by the flow rate, and the range and wet bulb would be of lesser importance.

Approach (5.5°C) = Cold-water temperature 32.2°C – Wet bulb temperature (26.7°C)

7.4.1.4 Heat load

The heat load imposed on a cooling tower is determined by the process being served. The degree of cooling required is controlled by the desired operating temperature of the process. In most cases, a low operating temperature is desirable to increase process efficiency or to improve the quality or quantity of the product. However, in some applications (e.g. internal combustion engines) high operating temperatures are desirable. The size and cost of the cooling tower increases with increase in heat load. Purchasing undersized equipment (if the calculated heat load is too low) and oversized equipment (if the calculated heat load is too high) is something to be aware of.

Process heat loads may vary considerably depending upon the process involved and are therefore difficult to determine accurately. On the other hand, air conditioning and refrigeration heat loads can be determined with greater accuracy.

Information is available for the heat rejection requirements of various types of power equipment. A sample list is as follows (Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers):

- Air Compressor
    - Single-stage - 129 kCal/kW/hr
    - Single-stage with after cooler - 862 kCal/kW/hr
    - Two-stage with intercooler - 518 kCal/kW/hr
    - Two-stage with intercooler and after cooler - 862 kCal/kW/hr
- Refrigeration, Compression - 63 kCal/min/TR
- Refrigeration, Absorption - 127 kCal/min/TR
- Steam Turbine Condenser - 555 kCal/kg of steam
- Diesel Engine, Four-Cycle, Supercharged - 880 kCal/kW/hr
- Natural Gas Engine, Four-cycle - 1523 kCal/kW/hr (= 18 kg/cm2 compression)

7.4.1.5 Wet bulb temperature

Wet bulb temperature is an important factor in performance of evaporative water cooling equipment, because it is the lowest temperature to which water can be cooled. For this reason, the wet bulb temperature of the air entering the cooling tower determines the minimum operating temperature level throughout the plant, process, or system. The following should be considered when pre-selecting a cooling tower based on the wet bulb temperature:

- Theoretically, a cooling tower will cool water to the entering wet bulb temperature. In practice, however, water is cooled to a temperature higher than the wet bulb temperature because heat needs to be rejected from the cooling tower.
- A pre-selection of towers based on the design wet bulb temperature must consider conditions at the tower site. The design wet bulb temperature also should not be exceeded for more than 5 percent of the time. In general, the design temperature selected is close to the average maximum wet bulb temperature in summer.
- Confirm whether the wet bulb temperature is specified as ambient (the temperature in the cooling tower area) or inlet (the temperature of the air entering the tower, which is often affected by discharge vapors recirculated into the tower). As the impact of recirculation cannot be known in advance, the ambient wet bulb temperature is preferred.
- Confirm with the supplier if the cooling tower is able to deal with the effects of increased wet bulb temperatures.
- The cold-water temperature must be low enough to exchange heat or to condense vapors at the optimum temperature level. The quantity and temperature of heat exchanged can be considered when choosing the right size cooling tower and heat exchangers at the lowest costs.

7.4.1.6 Relationship between range, flow and heat load

The range increases when the quantity of circulated water and heat load increase. This means that increasing the range as a result of added heat load requires a larger tower. There are two possible causes for the increased range:

- The inlet water temperature is increased (and the cold-water temperature at the exit remains the same). In this case it is economical to invest in removing the additional heat.
- The exit water temperature is decreased (and the hot water temperature at the inlet remains the same). In this case the tower size would have to be increased considerably because the approach is also reduced, and this is not always economical.

7.4.1.7 Relationship between approach and wet bulb temperature

The design wet bulb temperature is determined by the geographical location. For a certain approach value (and at a constant range and flow range), the higher the wet bulb temperature, the smaller the tower required. For example, a 4540 m^3/hr cooling tower selected for a 16.67°C range and a 4.45°C approach to 21.11°C wet bulb would be larger than the same tower to a 26.67°C wet bulb. The reason is that air at the higher wet bulb temperature is capable of picking up more heat. This is explained for the two different wet bulb temperatures:

- Each kg of air entering the tower at a wet bulb temperature of 21.1°C contains 18.86 kCal. If the air leaves the tower at 32.2°C wet bulb temperature, each kg of air contains 24.17 kCal. At an increase of 11.1°C, the air picks up 12.1 kCal per kg of air.
- Each kg of air entering the tower at a wet bulb temperature of 26.67°C contains 24.17 kCals. If the air leaves at 37.8°C wet bulb temperature, each kg of air contains 39.67 kCal. At an increase of 11.1°C, the air picks up 15.5 kCal per kg of air, which is much more than the first scenario.

7.4.2 Fill media effects

In a cooling tower, hot water is distributed above fill media and is cooled down through evaporation as it flows down the tower and gets in contact with air. The fill media impacts energy consumption in two ways:

- Electricity is used for pumping above the fill and for fans that create the air draft. An efficiently designed fill media with appropriate water distribution, drift eliminator, fan, gearbox and motor will therefore lead to lower electricity consumption.
- Heat exchange between air and water is influenced by surface area of heat exchange, duration of heat exchange (interaction) and turbulence in water effecting thoroughness of intermixing. The fill media determines all of these and therefore influences the heat exchange. The greater the heat exchange, the more effective the cooling tower becomes.

There are three types of fills:

- ***Splash fill media.*** Splash fill media generates the required heat exchange area by splashing water over the fill media into smaller water droplets. The surface area of the water droplets is the surface area for heat exchange with the air.
- ***Film fill media.*** In a film fill, water forms a thin film on either side of fill sheets. The surface area of the fill sheets is the area for heat exchange with the surrounding air. Film fill can result in significant electricity savings due to fewer air and pumping head requirements.
- ***Low-clog film fills.*** Low-clog film fills with higher flute sizes were recently developed to handle high turbid waters. Low clog film fills are considered as the best choice for sea water in terms of power savings and performance compared to conventional splash type fills.

Table 7.2: Design Values of Different Types of Fill (Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment – Fans and Blowers)

Parameters	Splash fill	Film fill	Low clog film fill
Possible L/G ratio	1.1 – 1.5	1.5 – 2.0	1.4 – 1.8
Effective heat exchange area	30 – 45 m^2/m^3	150 m^2/m^3	85 - 100 m^2/m^3
Fill height required	5 – 10 m	1.2 – 1.5 m	1.5 – 1.8 m
Pumping head required	9 – 12 m	5 – 8 m	6 – 9 m
Quantity of air required	High	Lowest	Low

7.4.3 Optimize cooling water treatment

Cooling water treatment (e.g. to control suspended solids, algae growth) is mandatory for any cooling tower independent of what fill media is used. With increasing costs of water, efforts to increase Cycles of Concentration (COC), by cooling water treatment would help to reduce make up water requirements significantly. In large industries and power plants improving the COC is often considered a key area for water conservation.

7.4.4 Install drift eliminators

It is very difficult to ignore drift problems in cooling towers. Nowadays most of the end user specifications assume a 0.02% drift loss. But thanks to technological developments and the production of PVC, manufacturers have improved drift eliminator designs. As a result drift losses can now be as low as 0.003–0.001%.

7.4.5 Cooling tower fans

The purpose of a cooling tower fan is to move a specified quantity of air through the system. The fan has to overcome the system resistance, which is defined as the pressure loss, to move the air. The fan output or work done by the fan is the product of air flow and the pressure loss. The fan output and kW input determines the fan efficiency.

The fan efficiency in turn is greatly dependent on the profile of the blade. Blades include:

- Metallic blades, which are manufactured by extrusion or casting processes and therefore it is difficult to produce ideal aerodynamic profiles
- Fiber reinforced plastic (FRP) blades are normally hand molded which makes it easier to produce an optimum aerodynamic profile tailored to specific duty conditions. Because FRP fans are light, they need a low starting torque requiring a lower HP motor, the lives of the gear box, motor and bearing is increased, and maintenance is easier.

An efficiency of 85% - 90% can be achieved with blades with an aerodynamic profile, optimum twist, taper and a high coefficient of lift to coefficient of drop ratio. However, this efficiency is drastically affected by factors such as tip clearance, obstacles to airflow and inlet shape, etc.

Cases reported where metallic or glass fiber reinforced plastic fan blades have been replaced by efficient hollow FRP blades. The resulting fan energy savings were in the order of 20-30% and with simple payback period of 6 to 7 months (NPC).

The chapter *Fans and Blowers* gives more information about fans.

7.5 Option Checklist

This section lists the most important options to improve energy efficiency of cooling towers.

- Follow manufacturer's recommended clearances around cooling towers and relocate or modify structures that interfere with the air intake or exhaust
- Optimize cooling tower fan blade angle on a seasonal and/or load basis
- Correct excessive and/or uneven fan blade tip clearance and poor fan balance
- In old counter-flow cooling towers, replace old spray type nozzles with new square spray nozzles that do not clog
- Replace splash bars with self-extinguishing PVC cellular film fill
- Install nozzles that spray in a more uniform water pattern
- Clean plugged cooling tower distribution nozzles regularly
- Balance flow to cooling tower hot water basins
- Cover hot water basins to minimize algae growth that contributes to fouling
- Optimize the blow down flow rate, taking into account the cycles of concentration (COC) limit
- Replace slat type drift eliminators with low-pressure drop, self-extinguishing PVC cellular units
- Restrict flows through large loads to design values
- Keep the cooling water temperature to a minimum level by (a) segregating high heat loads like furnaces, air compressors, DG sets and (b) isolating cooling towers from sensitive applications like A/C plants, condensers of captive power plant etc. *Note: A 1°C cooling water temperature increase may increase the A/C compressor electricity consumption by 2.7%. A 1°C drop in cooling water temperature can give a heat rate saving of 5 kCal/kWh in a thermal power plant*
- Monitor approach, effectiveness and cooling capacity to continuously optimize the cooling tower performance, but consider seasonal variations and site variations
- Monitor liquid to gas ratio and cooling water flow rates and amend these depending on the design values and seasonal variations. For example: increased water loads during summer times when approach is high and increase air flow during monsoon times and when approach is low.
- Consider COC improvement measures for water savings
- Consider energy efficient fibre reinforced plastic blade adoption for fan energy savings
- Control cooling tower fans based on exit water temperatures especially in small units
- Check cooling water pumps regularly to maximize their efficiency

7.6 References

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Chapter 8 Lighting System

8.1 Introduction

This section gives a brief background about lighting and the various basic terminology and definitions used in industry with regards to lighting.

8.1.1 Background

From the dawn of civilization until recent times, human beings created light solely from fire, though it is more a source of heat than light. We are still using the same principle in the 21st century to produce light and heat through incandescent lamps. Only in the past few decades have lighting products become much more sophisticated and varied. Estimates indicate that energy consumption by lighting is about 20 - 45% of a commercial building’s total energy consumption and about 3 - 10% in an industrial plant’s total energy consumption. Most industrial and commercial energy users are aware of energy savings in lighting systems. Often significant energy savings can be realized with a minimal investment of capital and common sense. Replacing mercury vapor or incandescent sources with metal halide or high pressure sodium will generally result in reduced energy costs and increased visibility. Installing and maintaining photo-controls, time clocks, and energy management systems can also achieve extraordinary savings. However, in some cases it may be necessary to consider modifications of the lighting design in order to achieve the desired energy savings. It is important to understand that efficient lamps alone would not ensure efficient lighting systems.

8.1.2 Basic Theory of Light

Light is just one portion of the various electromagnetic waves flying through space. These waves have both a frequency and a length, the values of which distinguish light from other forms of energy on the electromagnetic spectrum. Light is emitted from the body due to any of the following phenomena:

- **Incandescence:** Solids and liquids emit visible radiation when they are heated to temperatures about 1000K. The intensity increases and the appearance becomes whiter as the temperature increases.
- **Electric Discharge**: When an electric current is passed through a gas the atoms and molecules emit radiation whose spectrum is characteristic of the elements present.
- **Electro luminescence**: Light is generated when electric current is passed through certain solids such as semiconductor or phosphor materials.
- **Photoluminescence:** Radiation at one wavelength is absorbed, usually by a solid, and re-emitted at a different wavelength. When the re-emitted radiation is visible the phenomenon may be termed either *fluorescence* or *phosphorescence*.

Visible light, as can be seen on the electromagnetic spectrum, given in Figure 8.1, represents a narrow band between ultraviolet light (UV) and infrared energy (heat). These light waves are capable of exciting the eye's retina, which results in a visual sensation called sight. Therefore, seeing requires a functioning eye and visible light.

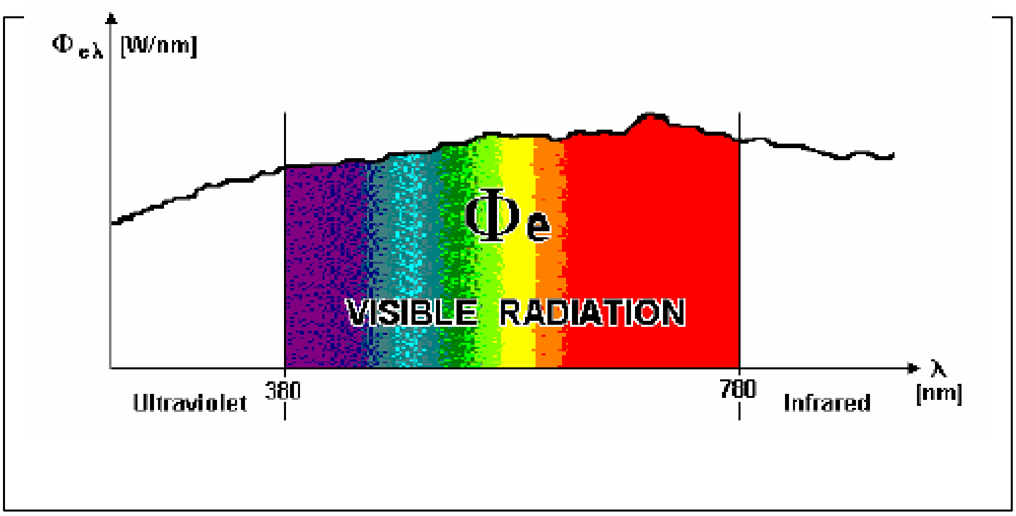


Figure 8.1. Visible Radiation

(*Energy Efficiency Guide for Industries in India, Electrical Energy Equipment: Cooling Towers*)

8.1.3 Definitions and Commonly Used Terms

Luminaire: A luminaire is a complete lighting unit, consisting of a lamp or lamps together with the parts designed to distribute the light, position and protect the lamps, and connect the lamps to the power supply.

Lumen: Unit of luminous flux; the flux emitted within a unit solid angle by a point source with a uniform luminous intensity of one candela. One lux is one lumen per square meter. The lumen (lm) is the photometric equivalent of the watt, weighted to match the eye response of the "standard observer". 1watt = 683lumens at 555nm wavelength.

Lux: This is the metric unit of measure for illuminance of a surface. Average maintained illuminance is the average of lux levels measured at various points in a defined area. One lux is equal to one lumen per square meter. The difference between the lux and the lumen is that the lux takes into account the area over which the luminous flux is spread. 1000 lumens, concentrated into an area of one square meter, lights up that square meter with an illuminance of 1000lux. The same 1000 lumens, spread out over ten square meters, produce a dimmer illuminance of only 100 lux.

Luminous Intensity and Flux: The unit of luminous intensity I is candela (cd) also known as the international candle. One lumen is equal to the luminous flux, which falls on each square meter (m2) of a sphere one meter (1m) in radius when a 1-candela isotropic light source (one that radiates equally in all directions) is at the center of the sphere. Since the area of a sphere of radius r is $4\pi r^2$, a sphere whose radius is 1m has $4\pi m^2$ of area, and the total luminous flux emitted by a 1- cd source is therefore 4π1m. Thus the luminous flux emitted by an isotropic light source of intensity I is given by:

Luminous flux (lm) = 4π × luminous intensity (cd)

Installed Load Efficacy: This is the average maintained illuminance provided on a horizontal working plane per circuit watt with general lighting of an interior expressed in lux/W/m^2.

Installed Load efficacy ratio: This is the ratio of *target load efficacy* and *installed load.*

Rated luminous efficacy: The ratio of rated lumen output of the lamp and the rated power consumption expressed in lumens per watt.

Room Index: This is a ratio, which relates the plan dimensions of the whole room to the height between the working plane and the plane of the fittings.

Target Load Efficacy: The value of Installed load efficacy considered being achievable under best efficiency, expressed in lux/W/m^2.

Utilization factor (UF): This is the proportion of the luminous flux emitted by the lamps, reaching the working plane. It is a measure of the effectiveness of the lighting scheme.

The Inverse Square Law

The inverse square law defines the relationship between the luminance from a point source and distance. It states that the intensity of light per unit area is inversely proportional to the square of the distance from the source (essentially the radius).

$$E = I / d^2$$

Where E = illuminance, I = luminous intensity and d = distance
An alternate form of this equation which is sometimes more convenient is:

$$E1\ d1^2 = E2\ d2^2$$

Distance is measured from the test point to the first luminating surface - the filament of a clear bulb, or the glass envelope of a frosted bulb.

Example: If one measures 10.0 lm/m^2 from a light bulb at 1.0 meter, what will the flux density be at half the distance?

Solution:

$$\begin{aligned} E1m &= (d2 / d1)^2 * E2 \\ &= (1.0 / 0.5)^2 * 10.0 \\ &= 40 \text{ lm/m}^2 \end{aligned}$$

Color Temperature

Color temperature, expressed on the Kelvin scale (K), is the color appearance of the lamp itself and the light it produces. Imagine a block of steel that is steadily heated until it glows first orange, then yellow and so on until it becomes “white hot.” At any time during the heating, we could measure the temperature of the metal in Kelvin (Celsius + 273) and assign that value to the color being produced. This is the theoretical foundation behind color temperature. For incandescent lamps, the color temperature is a "true" value; for fluorescent and high intensity discharge (HID) lamps, the value is approximate and is therefore called correlated color temperature. In the industry, “color temperature” and “correlated color temperature" are often used interchangeably. The color temperature of lamps makes them visually "warm," "neutral" or "cool" light sources. Generally speaking, the lower the temperature is, the warmer the source, and vice versa.

Color Rendering Index

The ability of a light source to render colors of surfaces accurately can be conveniently quantified by the color-rendering index. This index is based on the accuracy with which a set of test colors is reproduced by the lamp of interest relative to a test lamp, perfect agreement being given a score of 100. The CIE index has some limitations, but is the most widely accepted measure of the color rendering properties of light sources.

Table 8.1. Applications of color rendering groups (Energy Efficiency Guide for Industries in India, Electrical Energy Equipment: Cooling Tower)

Color rendering groups	CIE general color rendering Index(R_a)	Typical application
1A	Ra > 90	Wherever accurate color rendering is required e.g. color printing inspection
1B	80 < Ra < 90	Wherever accurate color judgments are necessary or good color rendering is required for reasons of appearance e.g. display lighting
2	60 < Ra < 80	Wherever moderate color rendering is required
3	40 < Ra < 60	Wherever color rendering is of little significance but marked distortion of color is unacceptable
4	20 < Ra < 40	Wherever color rendering is of no importance at all and marked distortion of color is acceptable

A common misconception is that color temperature and color rendering, both describe the same properties of the lamp. Again, color temperature describes the color appearance of the light source and the light emitted from it. Color rendering describes how well the light renders colors in objects.

Mounting height: The height of the fixture or lamp above the working plane.

8.2 Types of Lighting Systems

This section describes the various types and components of lighting systems.

8.2.1 Incandescent (GLS) Lamps

An incandescent lamp acts as a 'grey body', selectively emitting radiation, with most of it occurring in the visible region. The bulb contains a vacuum or gas filling. Although this stops oxidation of the tungsten filament, it will not stop evaporation. The darkening of bulbs is due to evaporated tungsten condensing on the relatively cool bulb surface. With an inert gas filling, the evaporation will be suppressed, and the heavier the molecular weight, the more successful it will be. For normal lamps an argon nitrogen mixture of ratio 9:1 is used because of its low cost. Krypton or Xenon is only used in specialized applications such as cycle lamps where the small bulb size helps to offset the increased cost, and where performance is critical.

Gas filling can conduct heat away from the filament, so low conductivity is important. Gas filled lamps normally incorporate fuses in the lead wires. A small break can cause an electrical discharge, which can draw very high currents. As filament fracture is the normal end of lamp life it would not be convenient for sub circuits fuses to fail.

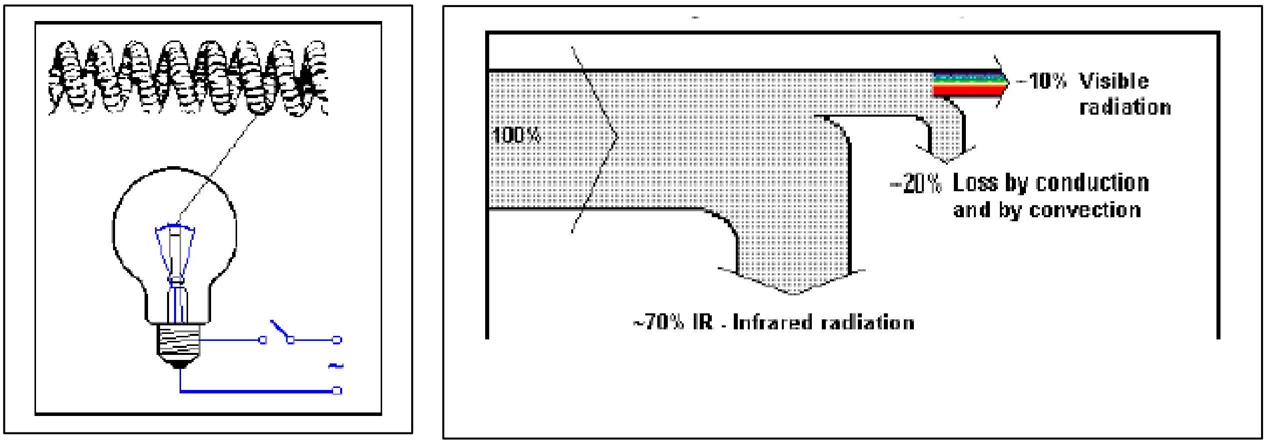


Figure 8.2. An Incandescent lamp and Energy Flow Diagram of Incandescent Lamp
(*Energy Efficiency Guide for Industries in Asia, Electrical Energy Equipment: Cooling Towers*)

Features
- Efficacy – 12 lumens/Watt
- Color Rendering Index – 1A
- Color Temperature - Warm (2,500K – 2,700K)
- Lamp Life – 1 to 2,000 hours

8.2.2 Tungsten--Halogen Lamps

A halogen lamp is a type of incandescent lamp. It has a tungsten filament just like a regular incandescent that you may use in your home, however the bulb is filled with halogen gas. Tungsten atoms evaporate from the hot filament and move toward the cooler wall of the bulb. Tungsten, oxygen and halogen atoms combine at the bulb-wall to form tungsten oxyhalide molecules. The bulb-wall temperature keeps the tungsten oxyhalide molecules in a vapor. The molecules move toward the hot filament where the higher temperature breaks them apart. Tungsten atoms are re-deposited on the cooler regions of the filament–not in the exact places from which they evaporated. Breaks usually occur near the connections between the tungsten filament and its molybdenum lead-in wires where the temperature drops sharply.

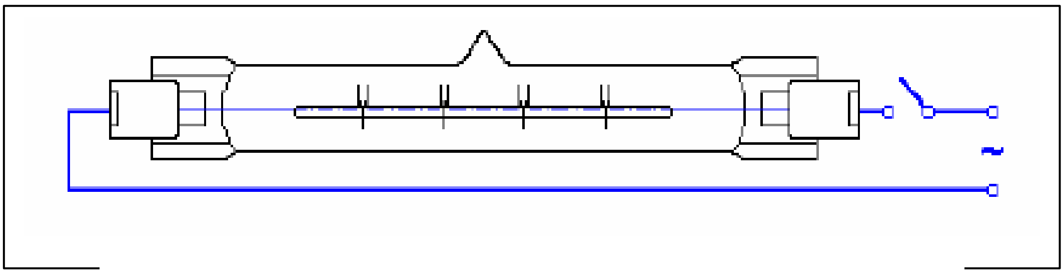


Figure 8.3 Tungsten halogen Lamps

Features:

- Efficacy – 18lumens/Watt
- Colour Rendering Index – 1A
- Colour Temperature – Warm (3,000K – 3,200K)
- Lamp Life – 2,000 to 4,000 hours

Advantages	Disadvantages
More compact	Higher cost
Longer Life	Increased IR
More Light	Increased UV
Whiter Light (Higher colour temperature)	Handling problem

8.2.3 Fluorescent Lamps

8.2.3.1 Features of fluorescent lamps

Fluorescent Lamps are about 3 to 5 times as efficient as standard incandescent lamps and can last about 10 to 20 times longer. Passing electricity through a gas or metallic vapour will cause electromagnetic radiation at specific wavelengths according to the chemical constitution and the gas pressure. The fluorescent tube has a low pressure of mercury vapour, and will emit a small amount of blue/green radiation, but the majority will be in the UV at 253.7nm and 185nm.

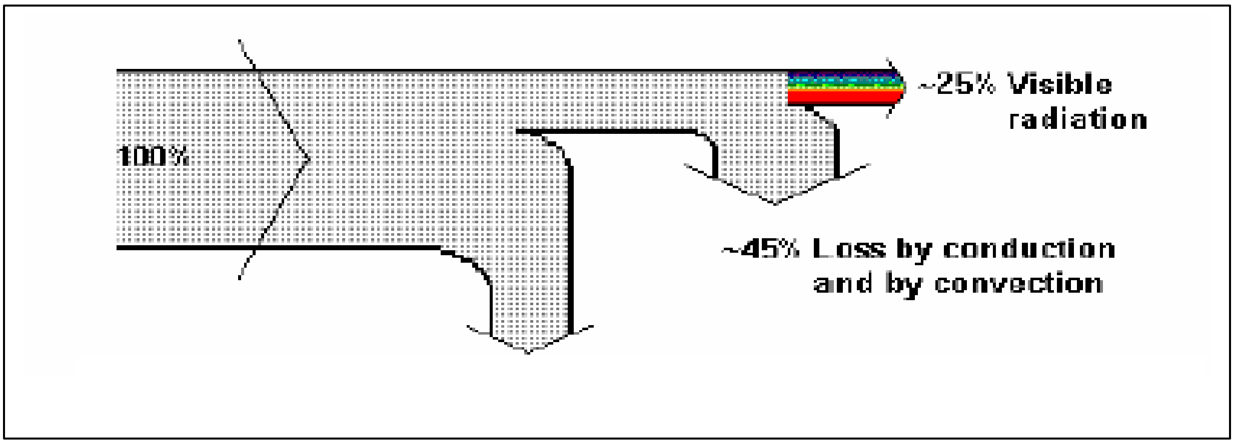


Figure 8.4a. Fluorescent lamp

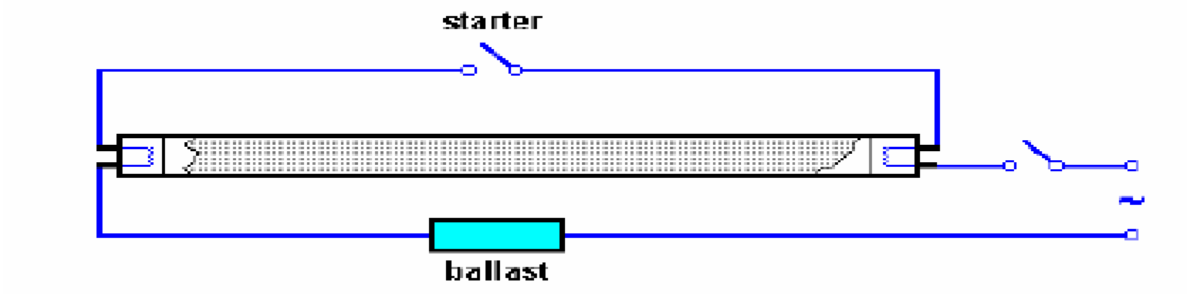


Figure 8.4b. Energy flow diagram of a fluorescent lamp

The inside of the glass wall has a thin phosphor coating, selected to absorb the UV radiation and transmit it in the visible region. This process is approx. 50% efficient. Fluorescent tubes are 'hot cathode' lamps, since the cathodes are heated as part of the starting process. The cathodes are tungsten filaments with a layer of barium carbonate. When heated, this coating will provide additional electrons to help start the discharge. This emissive coating must not be over-heated, as lamp life will be reduced. The lamps use a soda lime glass, which is a poor transmitter of UV. The amount of mercury is small, typically 12mg. The latest lamps are using a mercury amalgam, which enables doses closer to 5mg. This enables the optimum mercury pressure to be sustained over a wider temperature range. This is useful for exterior lighting as well as compact recessed fittings.

8.2.3.2 How do T12, T10, T8, and T5 fluorescent lamps differ?

These four lamps vary in diameter (ranging from 1.5 inches, which is 12/8 of an inch for T12 to 0.625 or 5/8 of an inch in diameter for T5 lamps). Efficacy is another area that distinguishes one from another. T5 & T8 lamps offer a 5-per cent increase in efficacy over 40-watt T12 lamps, and have become the most popular choice for new installations.

8.2.3.3 Effect of temperature

The most efficient lamp operation is achieved when the ambient temperature is between 20 and 30°C for a fluorescent lamp. Lower temperatures cause a reduction in mercury pressure, which means that less ultraviolet energy is produced; therefore, less UV energy is available to act on the phosphor and less light is the result. High temperatures cause a shift in the wavelength of UV produced so that it is nearer to the visual spectrum. The longer wavelengths of UV have less effect on the phosphor, and therefore light output is also reduced. The overall effect is that light output falls off both above and below the optimum ambient temperature range.

Features:

- Halophosphate
  - Efficacy – 80 lumens/Watt (HF gear increases this by 10%)
  - Colour Rendering Index – 2 to 3
  - Colour Temperature – Any
  - Lamp Life – 7,000 to 15,000 hours
- Triphosphor
  - Efficacy – 90 lumens/Watt
  - Colour Rendering Index – 1A to 1B
  - Colour Temperature – Any
  - Lamp Life – 7,000 to 15,000 hours

Compact fluorescents lamps

The recent compact fluorescent lamps open up a whole new market for fluorescent sources. These lamps permit design of much smaller luminaries, which can compete with incandescent and mercury vapour in the market of lighting fixtures having round or square shapes. Products in the market are available with either built in control gear (CFG) or separate control gear (CFN).

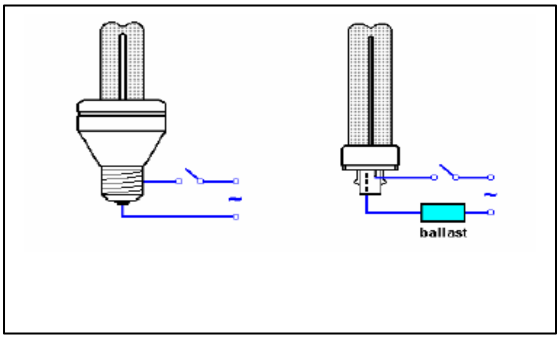


Figure 8.5 : CFL

Features
Efficacy – 60 lumens/Watt
Color Rendering Index – 1B
Color Temperature – Warm, Intermediate
Lamp Life – 7-10,000 hours

8.2.4 Sodium Lamps

8.2.4.1 High pressure sodium lamps

The high pressure sodium (HPS) lamp is widely used for outdoor and industrial applications. Its higher efficacy makes it a better choice than metal halide for these applications, especially when good color rendering is not a priority. HPS lamps differ from mercury and metal-halide lamps in that they do not contain starting electrodes; the ballast circuit includes a high-voltage electronic starter. The arc tube is made of a ceramic material, which can withstand temperatures up to 2372F. It is filled with xenon to help start the arc, as well as a sodium-mercury gas mixture.

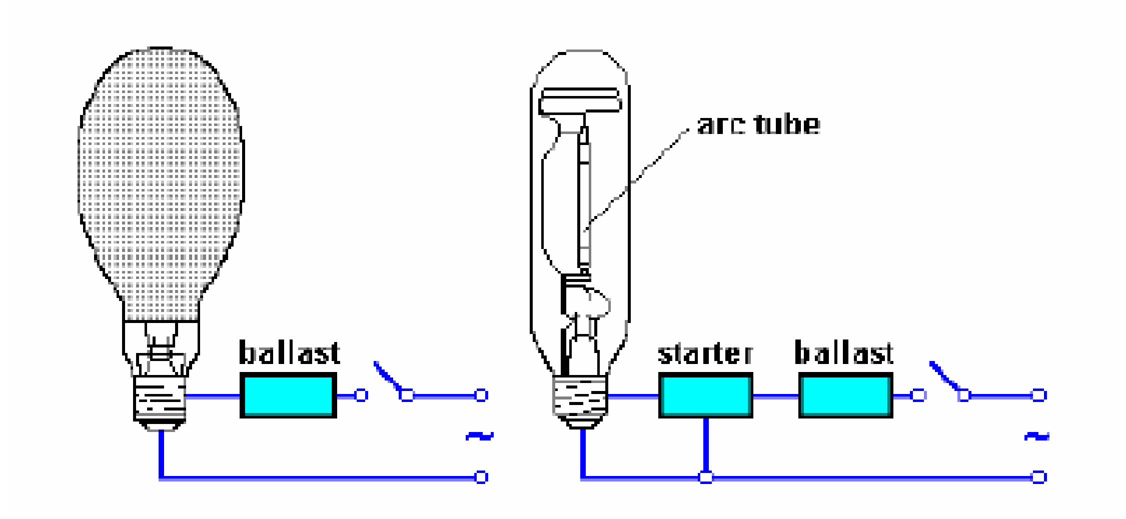


Figure 8.6. Sodium Vapour Lamp

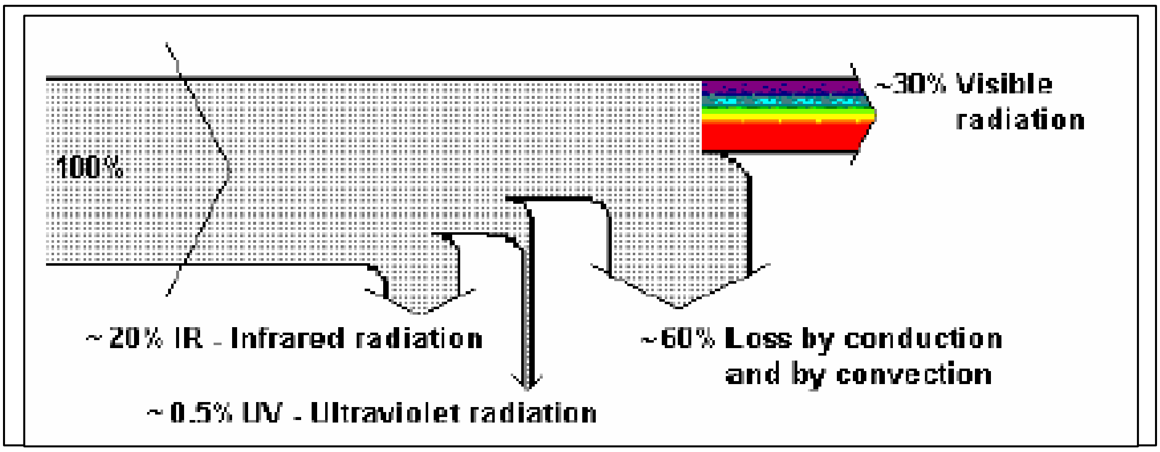


Figure 8.7: Energy flow diagram of sodium vapour lamp

Features

- Efficacy – 50 - 90 lumens/Watt (better CRI, lower Efficacy)
- Color Rendering Index – 1 – 2
- Color Temperature – Warm
- Lamp Life – 24,000 hours, excellent lumen maintenance
- Warm up – 10 minutes, hot re-strike – within 60 seconds
- Operating sodium at higher pressures and temperatures makes it highly reactive.
- Contains 1-6 mg sodium and 20mg mercury
- The gas filling is Xenon. Increasing the amount of gas allows the mercury to be reduced, but makes the lamp harder to start
- The arc tube is contained in an outer bulb that has a diffusing layer to reduce glare.
- The higher the pressure, the broader the wavelength band, and the better CRI, lower efficacy

8.2.4.2 Low pressure sodium lamps

Although low pressure sodium (LPS) lamps are similar to fluorescent systems (because they are low pressure systems), they are commonly included in the HID family. LPS lamps are the most successful light sources, but they produce the poorest quality light of all the lamp types. Being a monochromatic light source, all colors appear black, white, or shades of gray under an LPS source. LPS lamps are available in wattages ranging from 18-180. LPS lamp use has been generally limited to outdoor applications such as security or street lighting and indoor, low- wattage applications where color quality is not important (e.g. stairwells). However, because the color rendition is so poor, many municipalities do not allow them for roadway lighting.

Features

- Efficacy – 100 – 200 lumens/Watt
- Color Rendering Index – 3
- Color Temperature – Yellow (2,200K)
- Lamp Life – 16,000 hours
- Warm up – 10 minutes, hot re-strike – up to 3 minutes

8.2.5 Mercury Vapour Lamps

Mercury vapor lamps are the oldest style of HID lamp. Although they have long life and low initial cost, they have poor efficacy (30 to 65 lumens per watt, excluding ballast losses) and exude a pale green color. Perhaps the most important issue concerning mercury vapor lamps is how to best avoid them by using other types of HID or fluorescent sources that have better efficacy and color rendering. Clear mercury vapor lamps, which produce a blue-green light, consist of a mercury-vapor arc tube with tungsten electrodes at both ends. These lamps have the lowest efficacies of the HID family, rapid lumen depreciation, and a low color rendering index. Because of these characteristics, other HID sources have replaced mercury vapor lamps in many applications. However, mercury vapor lamps are still popular sources for landscape illumination because of their 24,000 hour lamp life and vivid portrayal of green landscapes. The arc is contained in an inner bulb called the arc tube. The arc tube is filled with high purity mercury and argon gas. The arc tube is enclosed within the outer bulb, which is filled with nitrogen.

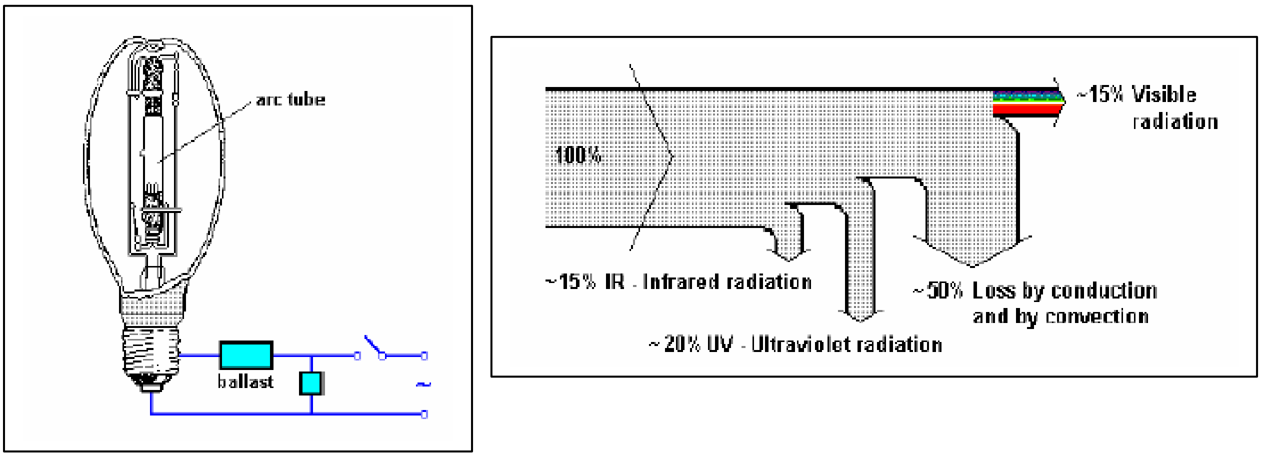


Figure 8.8 Mercury vapor lamp and its energy flow diagram

Features

- Efficacy – 50 - 60 lumens/Watt (excluded from part L)
- Color Rendering Index – 3
- Color Temperature –Intermediate
- Lamp Life – 16,000 - 24,000 hours, poor lumen maintenance
- Third electrode means control gear is simpler and cheaper to make. Some countries has used MBF for road lighting where the yellow SOX lamp was considered inappropriate
- Arc tube contains 100 mg mercury and argon gas. Envelope is quartz
- No cathode pre-heating; third electrode with shorter gap to initiate discharge
- Outer phosphor coated bulb. It provides additional red light using UV, to correct the blue/green bias of the mercury discharge
- The outer glass envelope prevents UV radiation escaping

8.2.6 Blended Lamps

Blended lamps are often described as two-in-one lamps. This combines two sources of light enclosed in one gas filled bulb. One source is a quartz mercury discharge tube (like a mercury lamp) and the other is a tungsten filament connected in series to it. This filament acts as a ballast for the discharge tube to stabilize the lam current; hence no other ballast is needed. The tungsten filament coiled in construction encircles the discharge tube and is connected in series with it. The fluorescent powder coating is given on the inside of the bulb wall to convert the emitted ultraviolet rays from the discharge tube to visible light.. At ignition, the lamp emits only light from the tungsten filament, and during the course of about 3 minutes, the arc in the discharge tube runs up to reach full light output. These lamps are suitable for flame proof areas and can fit into incandescent lamp fixtures without any modification.

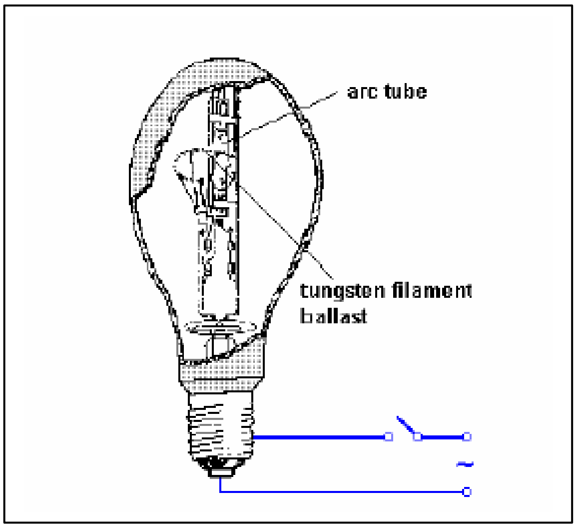


Figure 8.9 Blended lamps

Features

Typical rating - 160 W
Efficacy - 20 to 30 Lm/W
High power factor of 0.95
Life of 8000 hours

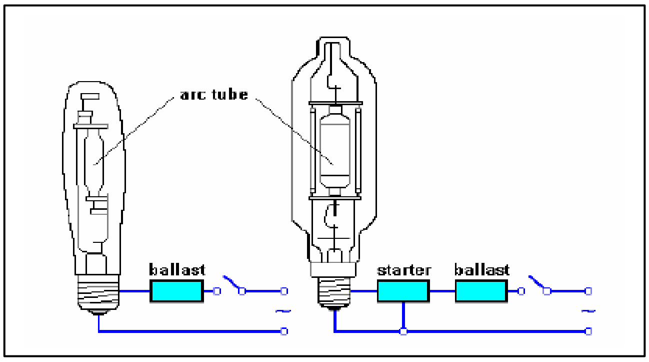
8.2.7 Metal Halide Lamps

The halides act in a similar manner to the tungsten halogen cycle. As the temperature increases there is disassociation of the halide compound releasing the metal into the arc. The halides prevent the quartz wall getting attacked by the alkali metals.

Features

- Efficacy – 80 lumens/Watt
- Color Rendering Index – 1A to 2 depends on halide mix
- Color Temperature – 3,000K to 6,000K
- Lamp Life – 6,000 to 20,000 hours, poor lumen maintenance
- Warm-up – 2-3 minutes, hot re-strike 10-20 minutes

- The choice of color, size and rating is greater for MBI than any other lamp type. They are a developed version of the two other high intensity discharge lamps, as they tend to have a better efficacy
- By adding other metals to the mercury different spectrum can be emitted
- Some MBI lamps use a third electrode for starting, but other, especially the smaller display lamps, require a high voltage ignition pulse



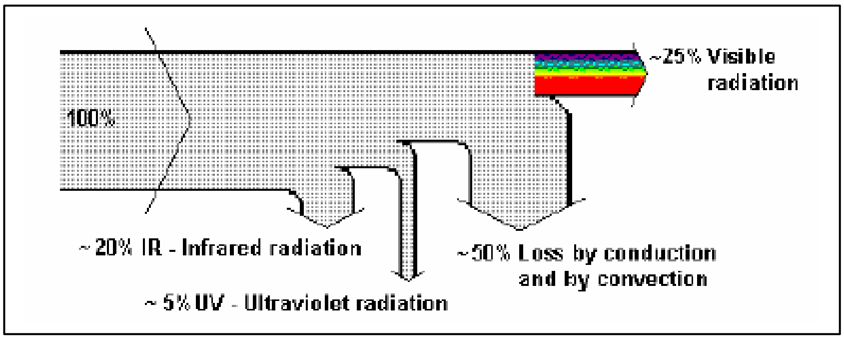


Figure 8.9. Metal halide lamp and its energy flow diagram

8.2.8 LED Lamps

8.2.8.1 Introduction to LED lighting

Light Emitting Diode (LED) is a relatively old technology that has advanced from numeric displays and indicator lights to a range of new applications including indoor lighting as well as outdoor lighting and street lighting. LED lamps are the newest addition to the list of energy efficient light sources. While LED lamps emit visible light in a very narrow spectral band, they can produce "white light". This is accomplished with either a red-blue-green array or a phosphor-coated blue LED lamp. LEDs offer benefits such as small size, long lamp life, low heat output, energy savings and durability. They also allow extraordinary design flexibility in color changing, dimming and distribution by combining these small units into desired shapes, colors, sizes and lumen packages. LED lamps last from 40,000 to 100,000 hours depending on the color.

8.2.8.2 Characteristics of LED lighting

LEDs are solid state semiconductor devices. LED illumination is achieved when a semiconductor crystal is excited so that it directly produces visible light in a desired wavelength range (color). LED units are small, typically 5mm (T 1-3/4).

8.2.8.3 Mode of operation

When an LED unit is activated, a power supply converts AC voltage into sufficient DC voltage, which is applied across the diode semiconductor crystal. This results in electrons (negative charge carriers [N]) in the diode's electron transport layer and holes (positive charge carriers [P]) in the diode's hole transport layer combining at the P-N junction and converting their excess energy into light. The LED is sealed in a clear or diffuse plastic lens that can provide a range of angular distributions of the light.

The color composition of the light being emitted by the LED is based on the chemical composition of the material being excited. LEDs are available that can produce colors including white, deep blue, blue, green, yellow, amber, orange, red, bright red and deep red.

8.2.8.4 Efficacy

LEDs are low-voltage, low-current devices and efficient light sources. For red, amber, yellow, green and blue LEDs, new materials have been developed that are more efficient than traditional materials, producing efficacies (lumens per watt) greater than incandescent lamps and fluorescent lamps. Efficacies as high as 100 Lumens/Watt are already available in the market. Various estimates of potential energy savings range from 82% to 93%. LED retrofit products, which come in various forms including light bars, panels and screw in LED lamps, typically draw 2-5W per sign, resulting in significant savings versus incandescent lamps with the bonus benefit of much longer life, which in turn reduces maintenance requirements.

8.2.9 Lighting Components

8.2.9.1 Luminaries/ Reflectors

The most important element in a light fitting, apart from the lamp(s), is the reflector. Reflectors impact on how much of the lamp's light reaches the area to be lit as well as the lighting distribution pattern. Reflectors are generally either diffuse (painted or powder coated white finish) or specular (polished or mirror-like). The degree of reflectance of the reflector material and the reflector's shape directly influence the effectiveness and efficiency of the fitting. Conventional diffuse reflectors have a reflectance of 70-80% when new. Newer high reflectance or semi-diffuse materials have reflectance as high as 85%. Conventional diffusers absorb much of the light and scatter it rather than reflecting it to the area required. Over time the reflectance values can decline due to the accumulation of dust and dirt as well as yellowing caused by the UV light. Specular reflectors are much more effective in that they maximise optics and specular reflectivity thus allowing more precise control of light and sharper cutoffs. In new-condition they have total reflectance values in the range of 85-96%. These values do not deteriorate as much as they do for conventional reflectors as they age. The most common materials used are anodized aluminium (85-90% reflectance) and silver film laminated to a metal substrate (91-95% reflectance). Enhanced (or coated) aluminium is used to a lesser extent (88-96% reflectance) Since they must remain clean to be effective, mirror optics reflectors should not be used in industrial-type open strip fixtures where they are likely to be covered with dust.

Figure 8.10. Mirror Optics Luminaire

8.2.9.2 Gear

The gears used in the lighting equipment are as follows:

- ***Ballast:*** A current limiting device, to counter negative resistance characteristics of any discharge lamps. In case of fluorescent lamps, it aids the initial voltage build-up, required for starting.
- ***Ignitors:*** These are used for starting high intensity Metal Halide and Sodium vapour lamps. The following Table gives the performance characteristics of the commonly used luminaries:

Table 8.2 Luminous Performance Characteristics of Commonly Used Luminaries

Type of Lamp	Lumens/Watt		Colour Rendering Index	Application	Life (Hours)
	Range	Average			
Incandescent	8 - 18	14	Excellent	Homes, restaurants, general lighting, emergency lighting	1000
Fluorescent	46 - 60	50	Good w.r.t coating	Offices, shops, hospitals, homes	5000
Compact Fluorescent Lamps (CFL)	40 - 70	60	Very good	Hotels, shops, homes, offices	8000 – 10000
High Pressure Mercury Vapour (HPMV)	44 - 57	50	Fair	General lighting in factories, garages, car parking, flood lighting	5000
Halogen Lamps	18 - 24	20	Excellent	Display, flood lighting, stadium exhibition area, construction area	2000 - 4000
High Pressure Sodium Vapour (HPSV)	67 - 121	90	Fair	General lighting in factories, warehouses, street lighting	6000 – 12000
Low Pressure Sodium Vapour (LPSV)	101 - 175	150	Poor	Roadways, tunnels, canals, street lighting	6000 – 12000

Type of Lamp	Lumens/Watt		Colour	Application	Life (Hours)
LED	90 - 120	100	Good	General lighting, homes, restaurants, street lighting	50000 - 100000
Induction Lamps	90 - 110	100	Good	General lighting, industrial lighting, street lighting	80000 - 100000

8.3 Assessment of Lighting Systems

This section includes the designing of a lighting system for interiors and also the methodology of a lighting system energy efficiency study. It also gives the recommended values of the illuminance required for various types of work as per the Indian standard.

8.3.1 Designing of Lighting System

8.3.1.1 How much light is needed?

Every task requires some lighting level on the surface of the body. Good lighting is essential to perform visual tasks. Better lighting permits people to work with more productivity. Typical book reading can be done with 100 to 200 lux. The question before the designer is hence, firstly, to choose the correct lighting level. CIE (Commission International de l'Eclairage) and IES (Illuminating Engineers Society) have published recommended lighting levels for various tasks. These recommended values have since made their way into national and international standards for lighting design (see Table given below). The second question is about the quality of light. In most contexts, quality is read as color rendering.
Depending on the type of task, various light sources can be selected based on their color-rendering index.

Table 8.3. Illuminance Levels for different Areas of Activity

Type of area	Illuminance Level (lux)	Examples of area of activity
General lighting for rooms and areas used either infrequently and/or casual or simply visual tasks	20	Minimum service illuminance in exterior circulating area, outdoor areas, stockyards
	50	Exterior walkways and platforms
	70	Boiler house
	100	Transformer yard, furnace rooms etc.
	150	Circulation areas in industries, stores and stock rooms
General lighting for interiors	200	Minimum service illuminance on task
	300	Medium bench & machine work, general process in chemical and food industries, casual reading and filling activities
	450	Hangers, inspection, drawing offices, fine bench and machinery assembly, colour work, critical drawing task
	1500	Very fine bench and machine work, instrument & small precision mechanism assembly, electronic components, gauging & inspection of small intricate parts (maybe partly provided by local task lighting)
Additional localized lighting for visually exacting task	3000	Minutely detailed and precise work, e.g. very small parts of instruments, watch making, engraving

8.3.1.2 Lighting design for interiors

The step by step process of lighting design is illustrated below with the help of an example. The following figure shows the parameters of a typical space.

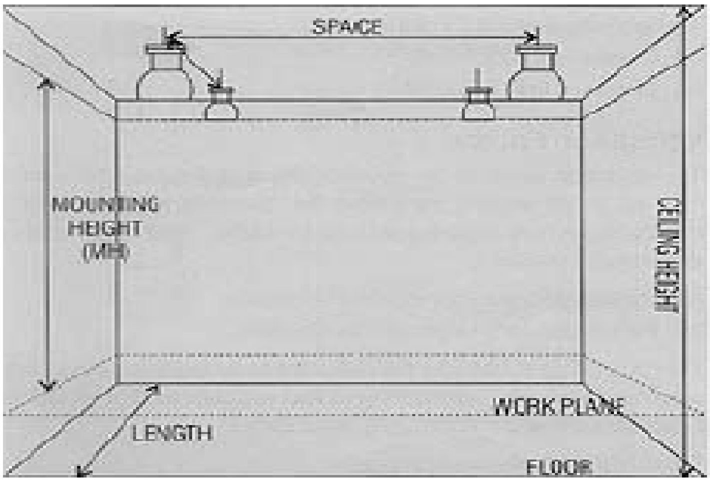


Figure 8.11. Room with dimensions

Step 1: Decide the required illuminance on work plane, the type of lamp and luminaire

A preliminary assessment must be made of the type of lighting required, a decision most often made as a function of both aesthetics and economics. For normal office work, illuminance of 200 lux is desired.

For an air-conditioned office space under consideration, we choose 36 W fluorescent tube lights with twin tube fittings. The luminaire is porcelain-enamelled, suitable for the above lamp. It is necessary to procure utilization factor tables for this luminaire from the manufacturer for further calculations.

Step 2: Collect the room data in the format given below

Room dimensions	Length	L1	10	m
	Width	L2	10	m
	Floor area	L3	100	m2
	Ceiling Height	L4	3.0	m
Surface reflectance	Ceiling	L5	0.7	p.u
	Wall	L6	0.5	p.u
	Floor	L7	0.2	p.u
Work plane height from floor		L8	0.9	m
Luminaire height from floor		L9	2.9	m

Typical reflectance values for using in L5, L6, L7 are:

	Ceiling	Walls	Floor
Air Conditioned Office	0.7	0.5	0.2
Light Industrial	0.5	0.3	0.1
Heavy Industrial	0.3	0.2	0.1

Step 3: Calculate room index

$$Room\ index = \frac{Length\ \times Breadth}{Height\ \times (Length + Breadth)}$$

= 10 X 10 / [2 *(10 + 10)] = 2.5

Step 4: Calculating the Utilization factor

Utilization factor is defined as the per cent of rated bare-lamp lumens that exit the luminaire and reach the work plane. It accounts for light directly from the luminaire as well as light reflected off the room surfaces. Manufacturers will supply each luminaire with its own CU table derived from a photometric test report. Using tables available from manufacturers, it is possible to determine the utilization factor for different light fittings if the reflectance of both the walls and ceiling is known, the room index has been determined and the type of luminaire is known. For twin tube fixture, utilization factor is 0.66, corresponding to room index of 2.5.

Step 5: Calculate the number of fittings required by applying the following formula:

$$N = \frac{E \times A}{F \times UF \times LLF}$$

Where:
N = Number of fittings
E = Lux level required on working plane
A = Area of room (L x W)
F = Total flux (Lumens) from all the lamps in one fitting
UF = Utilization factor from the table for the fitting to be used

LLF = Light loss factor. This takes account of the depreciation over time of lamp output and dirt accumulation on the fitting and walls of the building.

LLF = Lamp lumen $_{MF}$ x Luminaire $_{MF}$ x Room surface $_{MF}$

Typical LLF Values

Air Conditioned Office	0.8
Clean Industrial	0.7
Dirty Industrial	0.6

$$N = \frac{200 \times 100}{2 \times 3050 \times 0.66 \times 0.8}$$

= 6.2;

So, 6 nos twin tube fixtures are required. Total number of 36-Watt lamps is 12.

Step 6: Space the luminaires to achieve desired uniformity

Every luminaire will have a recommended space to height ratio. In earlier design methodologies, the uniformity ratio, which is the ratio of minimum illuminance to average illuminance was kept at 0.8 and suitable space to height ratio is specified to achieve the uniformity. In modern designs incorporating energy efficiency and task lighting, the emerging concept is to provide a uniformity of 1/3 to 1/10 depending on the tasks. Recommended value for the above luminaire is 1.5. If the actual ratio is more than the recommended values, the uniformity of lighting will be less. For a sample of arrangement of fittings, refer figure 8.12. The luminaire closer to a wall should be one half of a spacing or less.

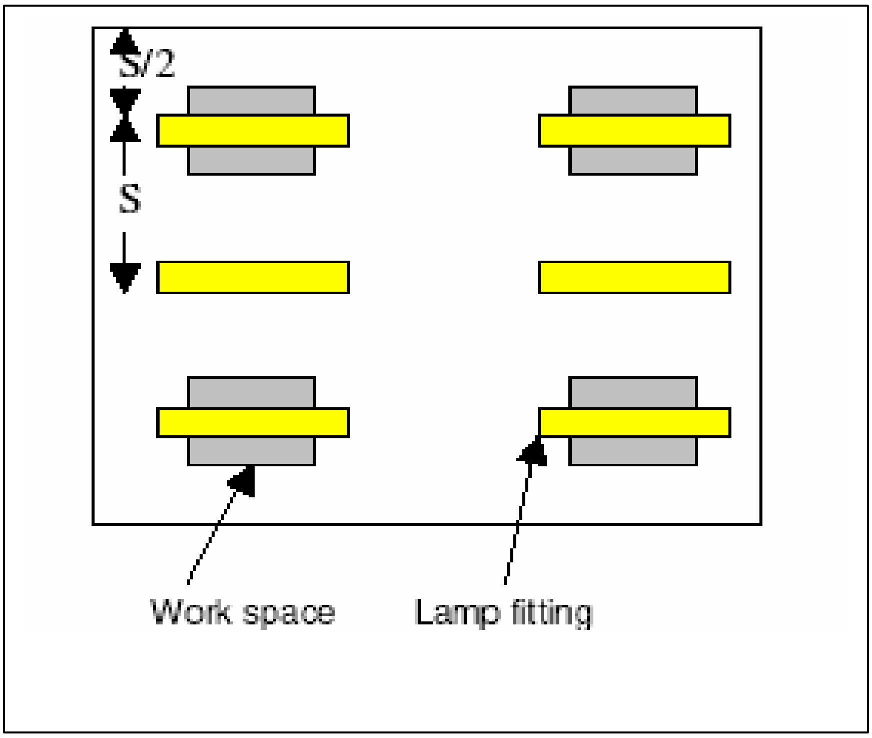


Figure 8.12. Luminaire spacing

Spacing between luminaires = 10/3 = 3.33 meters
Mounting height = 2.0 m
Space to height ratio = 3.33/2.0 = 1.66
This is close to the limits specified and hence accepted.

It is better to choose luminaires with larger SHR. This can reduce the number of fittings and connected lighting load.

8.3.2 Recommended Illuminance Levels For Various Tasks / Activities / Locations

8.3.2.1 Recommendations on illuminance

Scale of Illuminance: The minimum illuminance for all non-working interiors, has been mentioned as 20 Lux (**as per IS 3646**). A factor of approximately 1.5 represents the smallest significant difference in subjective effect of illuminance. Therefore, the following scale of illuminances is recommended. 20-30-50-75-100-150-200-300-500-750-1000-1500-2000 lux

Illuminance ranges: Because circumstances may be significantly different for different interiors used for the same application or for different conditions for the same kind of activity, a range of illuminances is recommended for each type of interior or activity intended of a single value of illuminance. Each range consists of three successive steps of the recommended scale of illuminances. For working interiors the **middle value (R**) of each range represents the recommended service illuminance that would be used unless one or more of the factors mentioned below applies.

The **higher value (H)** of the range should be used at exceptional cases where low reflectances or contrasts are present in the task, errors are costly to rectify, visual work is critical, accuracy or higher productivity is of great importance and the visual capacity of the worker makes it necessary.

Similarly, **lower value (L)** of the range may be used when reflectances or contrasts are unusually high, speed & accuracy is not important and the task is executed only occasionally.

<u>Recommended Illumination</u>

The following table gives the recommended illuminance range for different tasks and activities. The values are related to the visual requirements of the task, to user's satisfaction, to practical experience and to the need for cost effective use of energy**.**

Metal Manufacture & Iron making	
Sinter plant:	
Plant floor	150-200-300
Mixer drum, fan house, screen houses, coolers, transfer stations	100-150-200
Furnaces, cupola:	
General	100-150-200
Control platforms	200-300-500
Conveyor galleries, walkways	30-50-100
Steel Making	
Electric melting shops	150-200-300
Basic oxygen steel making plants	
General	100-150-200
Converter floor, teeming bay	150-200-300
Control platforms	200-300-500
Scrap bays	100-150-200
Metal forming and treatment	

Ingot stripping, soaking pits, annealing and heat treatment bays, acid	150-200-300
Pickling and cleaning bays, roughing mills, cold mills finishing mills, tinning and galvanizing lines, cut up and	
General	100-150-200
Control platforms	200-300-500
Wire mills, product finishing, steel inspection & treatment	200-300-500
Plate/strip inspection	300-500-700
Foundries	
Automatic plant	
Without manual operation	30-50-100
With occasional manual operation	100-150-200
With continuous manual operation	200-300-500
Control room	200-300-500
Control platforms	200-300-500
Non-automatic plants	
Charging floor, pouring, shaking out, cleaning, grinding fettling	200-300- 500
Rough molding, rough core making	200-300-500
Fine molding, fine core making	300-500-750
Inspection	300-500-750
Forges (severe vibration is likely to occur)	
General	200-300-500
Inspection	300-500-750
Ceramics Concrete products	
Mixing, casting, cleaning	150-200-300
Potteries	
Grinding, molding, pressing, cleaning, trimming, glazing, firing	200-300- 500
Enamelling, coloring	500-750-1000
Glass works	
Furnace rooms, bending, annealing	100-150-200
Mixing rooms, forming, cutting, grinding, polising, toughening	200-300-500
Bevelling, decorative cutting, etching, silvering	300-500-750
Inspection	300-500-750
Chemicals, petroleum, and chemical and petrochemical works	
Exterior walkways, platforms, stairs and ladders	30-50-100
Exterior pump and valve areas	50-100-150
Pump and compressor houses	100-150-200
Process plant with remote control	30-50-100
Process plant requiring occasional manual intervention	50-100-150
Permanently occupied work stations in process plant	150-200-300
Control rooms for process plant	200-300-500
Pharmaceuticals Manufacturer and Fine chemicals manufacturer	
Pharmaceutical manufacturer	
Grinding, granulating, mixing, drying, tableting, sterilising, washing, preparation of solutions, filling, capping, wrapping, hardening	300-500-750
Fine chemical manufacturers	

Exterior walkways, platforms, stairs and ladders	30-50-100
Process plant	50-100-150
Fine chemical finishing	300-500-750
Inspection	300-500-750
Soap manufacture	
General area	200-300-500
Automatic processes	100-200-300
Control panels	200-300-500
Machines	200-300-500
Paint works	
General	200-300-500
Automatic processes	150-200-300
Control panels	200-300-500
Special batch mixing	500-750-1000
Color matching	750-100-1500
Mechanical engineering & Structural steel fabrication	
General	200-300-500
Marking off	300-500-750
Sheet metal works	
Pressing, punching shearing, stamping, spinning, folding	300-500-750
Bench work, scribing, inspection	500-750-1000
Machine and tool shops	
Rough bench and machine work	200-300-500
Medium bench and machine work	300-500-700
Fine bench and machine work	500-750-1000
Gauge rooms	750-1000-1500
Die sinking shops	
General	300-500-750
Fine work	1000-1500-2000
Welding and soldering shops	
Gas and arc welding, rough spot welding	200-300-500
Medium soldering, brazing, spot welding	300-500-750
Fine soldering, fine spot welding	750-1000-1500
Assembly shops	
Rough work e.g., frame and heavy machine assembly	200-300-500
Medium work, e.g., engine assembly, vehicle body assembly	300-500-750
Fine work, e.g., office machinery assembly	500-750-1000
Very fine work, e.g., instrument assembly	750-1000-1500
Minute work, e.g., watch making	1000-1500-2000
Inspection and testing shops	
Coarse work, e.g., using go/no go gauges, inspection of large sub-Assemblies	300-500-750
Medium work, e.g., inspection of painted surfaces	500-750-1000
Fine work, e.g., using calibrated scales, inspection of precision Mechanisms	750- 1000-1500
Very fine, e.g., inspection of small intricate parts	1000-1500-2000
Minute work, e.g., inspection of very small instruments	2000
Paints shops and spray booths	

Dipping, rough spraying	200-300-500
Preparation, ordinary painting, spraying and finishing	200-500-750
Fine painting, spraying and finishing	500-750-1000
Inspection, retouching and matching	750-1000-1500
Plating shops	
Vats and baths	200-300-500
Buffing, polishing, burnishing	300-500-750
Final buffing and polishing	500-750-1000
Inspection -	
Electrical and electronic engineering, and electrical equipment manufacture	
Manufacture of cables and insulated wires, winding varnishing and immersion of coils, assembly of large machines, simple assembly	200-300-500
Medium assembly, e.g., telephones, small motors	300-500-750
Assembly of precision components, e.g., telecommunications	750-1000-1500
Assembly of high precision parts	1000-1500-2000
Electronic equipment manufacture	
Printed circuit board	
Silk screening	300-500-750
Hand insertion of components, soldering	500-750-1000
Inspection	750-1000-1500
Assembly of wiring harness, cleating harness, testing and calibration	500-750- 1000
Chassis assembly	750-1000-1500
Inspection and testing	
Soak test	150-200-300
Safety and functional tests	200-300-500
Food, drink, tobacco, and slaughter houses	
General	200-300-500
Inspection	300-500-750
Canning, preserving and freezing	
Grading and sorting of raw materials	500-750-1000
Preparation	300-500-750
Canned and bottled goods	
Retorts	200-300-500
Automatic processes	150-200-300
Labeling and packaging	200-300-500
Frozen foods	
Process area	200-300-500
Packaging and storing	200-300-500
Bottling, brewing and distilling	
Key washing and handling, bottle washing	150-200-300
Key inspection	200-300-500
Bottle inspection	
Process areas	200-300-500
Bottle filling	500-750-1000
Edible oils and fats processing	
Refining and blending	200-300-500
Production	300-500-750

Mills-milling, filtering and packing	200-300-500
Bakeries	
General	200-300-500
Hand decorating, icing	300-500-750
Chocolate and confectionery manufacture General	200-300-500
Automatic processes	150-200-300
Hand decoration, inspection, wrapping and packing	300-500-750
Tobacco processing	
Material preparation, making and packing	300-500-750
Hand processes	500-750-1000
Textiles & Fiber preparation	
Bale breaking, washing	200-300-500
Stock dyeing, tinting	200-300-500
Yarn manufacture	
Spinning, roving, winding, etc.	300-500-750
Healding (drawing in)	750-1000-750
Fabric production	
Knitting	300-500-750
Weaving	
Jute and hemp	200-300-500
Heavy woolens	300-500-750
Medium worsteds, fine wollens, cottons	500-750-1000
Fine worsteds, fine linens, synthetics	750-1000-1500
Mending	1000-1500-2000
Inspection	1000-1500-2000
Fabric finishing	
Dyeing	200-300-500
Calendaring, chemical treatment, etc.	300-500-750
Inspection	
Grey cloth	750-1000-1500
Final	1000-1500-2000
Carpet manufacture	
Winding, beaming	200-300-500
Setting pattern, tufting cropping, trimming, fringing, latexing and	300-500-750
Designing, weaving, mending	500-750-1000
Inspection	
General	750-1000-1500
Piece dyeing	500-750-1000
Leather industry & Leather manufacture	
Cleaning, tanning and stretching, vats, cutting, fleshing, stuffing	200-300- 500
Finishing, scarfing	300-500-750
Leather working	
General	200-300-500
Pressing, glazing	300-500-750
Cutting, splitting, scarfing, sewing	500-750-1000
Grading, matching	
Clothing, footwear, and clothing manufacture	
Preparation of cloth	200-300-500

Cutting	500-750-1000
Matching	500-750-1000
Sewing	750-1000-1500
Pressing	300-500-750
Inspection	1000-1500-2000
Hand tailoring	1000-1500-2000
Hosiery and knitwear manufacture	
Flat bed knitting machines	300-500-750
Circular knitting machines	500-700-1000
Lockstitch and over locking machine	750-1000-1500
Linking or running on	750-1000-1500
Mending, hand finishing	1000-1500-3000
Inspection	1000-1500-2000
Glove manufacture	
Sorting and grading	500-750-1000
Pressing, knitting, cutting	300-500-750
Sewing	500-750-1000
Inspection	1000-1500-2000
Hat manufacture	
Stiffening, braiding, refining, forming, sizing, pounding, ironing	200- 300-500
Cleaning, flanging, finishing	300-500-750
Sewing	500-750-1000
Inspection	1000-1500-2000
Boot and shoe manufacture	
Leather and synthetics	
Sorting and grading	750-1000-1500
Clicking, closing	750-1000-1500
Preparatory operations	750-1000-1500
Cutting tables and pressure	1000-1500-2000
Button stock preparation, lasting, bottoming finishing, shoe rooms	750-1000- 1500
Rubber	
Washing, compounding, coating, drying, varnishing, vulcanizing, calendaring, cutting	200-300-500
Lining, making and finishing	300-500-750
Timber and Furniture Sawmills	
General	150-200-300
Head saw	300-500-750
Grading	500-750-1000
Woodwork shops	
Rough sawing, bench work	200-300-500
Sizing, planning, sanding, medium machining and bench work	300-500-750
Fine bench and machine work, fine sanding, finishing	500-750-1000
Furniture manufacture	
Raw material stores	50-100-150
Finished goods stores	100-150-200
Wooe matching and assembly, rough sawing, cutting	200-300-500
Machining, sanding and assembly, polishing	300-500-750
Tool rooms	300-500-750
Spray booths	

Color finishing	300-500-750
Clear finishing	200-300-500
Cabinet making	
Veneer sorting and grading	750-1000-1500
Marquetry, pressing, patching and fitting	300-500-750
Final inspection	500-750-1000
Upholstery manufacture	
Cloth inspection	1000-1500-2000
Filling, covering	300-500-750
Slipping, cutting, sewing	500-750-1000
Mattress making -	
Assembly	300-500-750
Tape edging	750-1000-1500
Paper and Printing Paper mills	
Pulp mills, preparation plants	200-300-500
Paper and board making	
General	200-300-500
Automatic process	150-200-300
Inspection, sorting	300-500-750
Paper converting process	
General	200-300-750
Associated printing	300-500-750
Printing works	
Type foundries	
Matrix making, dressing type, hand and machine coating	200-300-500
Front assembly, sorting	500-750-1000
Composing rooms	
Hand composing, imposition and distribution	500-750-1000
Hot metal keyboard	500-750-1000
Hot metal casting	200-300-500
Photo composing keyboard or setters	300-500-750
Paste up	500-750-1000
Illuminated tables -- general lighting	200-300-500
Proof presses	300-500-750
Proof reading	500-750-1000
Graphic reproduction	
General	300-500-750
Precision proofing, retouching, etching	750-1000-1500
Color reproduction and inspection	750-1000-1500
Printing machine room	
Presses	300-500-750
Premake ready	300-500-750
Printed sheet inspection	750-1000-1500
Binding	
Folding, pasting, punching and stitching	300-500-750
Cutting, assembling, embossing	500-750-1000
Plastics & Rubber plastic products	
Automatic plant	

Without manual control	30-50-100
With occasional manual control	50-100-150
With continuous manual control	200-300-500
Control rooms	200-300-500
Control platforms	200-300-500
Non-automatic plant	
Mixing, calendaring, extrusion, injection,	200-300-500
compression and blow moulding, sheet fabrication Trimming, cutting, polishing, cementing	300-500-750
Printing, inspection	750-1000-1500
Rubber production	
Stock preparation -- plasticising, milling	150-200-300
Calendaring, fabric preparation, stock-cutting	300-500-750
Extruding, moulding	300-500-750
Inspection	750-1000-1500

8.3.3 Methodology of Lighting System Energy Efficiency Study

A step by step approach to assessment of improvement options in lighting at any facility would involve the following likely steps.

Step 1: Inventory the lighting system elements, & transformers in the facility as per following typical format.

Device rating, population and use profile:

Sl. No.	Plant Location	Lighting Device & Ballast Type	Rating in Watts Lamp and Ballast	Population/ Numbers	Use per shift as I/II/III shifts per day

Lighting transformer / rating and population profile :

Sl. No.	Plant Location	Lighting transformer rating, kVA	Numbers installed	Measurement provisions available, Volts/Amps/kW/Energy

Step 6: Based on careful assessment and evaluation, identify improvement options, which could include:

- Maximum sunlight use options through transparent roof sheets, north light roof, etc.
- Replacements of lamps by more energy efficient lamps, with due consideration to luminaire, color rendering index and lux level as well as expected life comparison.
- Replacements of ballasts by more energy efficient ballasts, with due consideration to life and power factors apart from watt loss.
- Selecting interior colors for light reflection.
- Modify the layout as per needs.
- Providing individual / group controls for lighting for energy efficiency such as:
    - On / off type voltage regulation type (for illuminance control)
    - Group control switches / units
    - Occupancy sensors
    - Photovoltaic controls
    - Mechanical timer operated controls
    - Pager operated controls
    - Computerized lighting control programmes
- Installation of input voltage regulators / controllers for energy efficiency as well as longer life expectancy of lamps where higher voltages, fluctuations are expected.
- Instances of energy efficient displays like LED's in place of lamp type displays in control panels / instrumentation areas, etc.

8.4 Energy Efficiency Opportunities

This section gives the various means and ways by which energy could be conserved by applying good lighting practices.

8.4.1 Use Natural Day Lighting

The utility of using natural day lighting instead of electric lighting during the day is well known, but is being increasingly ignored especially in modern air-conditioned office spaces and commercial establishments like hotels, shopping plazas etc. Industrial plants generally use daylight in some fashion, but improperly designed day lighting systems can result in complaints from personnel or supplementary use of electric lights during daytime. Consider an application that needs an illumination level of 500 lux. To account for losses in reflection and diffusion within the skylight assembly, assume that 40% of the sunlight entering the skylight makes its way into the space. Thus, on a bright day, about 2% of the ceiling area needs to be skylights. To compensate for low sun angles, hazy conditions, dirty skylights, etc., double this to about 4%. To account for average cloudy conditions, increase this to 10% or 15%. Some of the methods to incorporate day lighting are:

- North lighting by use if single-pitched truss of the saw-tooth type is a common industrial practice; this design is suitable for latitudes north of 23 i.e. in North India. In South India, north lighting may not be appropriate unless diffusing glasses are used to cut out the direct sunlight.
- Innovative designs are possible which eliminates the glare of daylight and blend well with the interiors. Glass strips, running continuously across the breadth of the roof at regular intervals, can provide good, uniform lighting on industrial shop floors and storage bays.

- A good design incorporating sky lights with FRP material along with transparent or translucent false ceiling can provide good glare-free lighting; the false ceiling will also cut out the heat that comes with natural light.
- Use of atrium with FRP dome in the basic architecture can eliminate the use of electric lights in passages of tall buildings.
- Natural light from windows should also be used. However, it should be well designed to avoid glare. Light shelves can be used to provide natural light without glare.

Figure 8.13. Day lighting with poly carbonated sheets

Figure 8.14. Atrium with FRP dome

8.4.2 De-lamping to reduce excess lighting

De-lamping is an effective method to reduce lighting energy consumption. In some industries, reducing the mounting height of lamps, providing efficient luminaires and then de-lamping has ensured that the illuminance is hardly affected. De-lamping at empty spaces where active work is not being performed is also a useful concept. There are some issues rated to de-lamping with reference to the connection of lamps and ballasts in a multi-lamp fixture. There are series and parallel-wired ballasts. Most magnetic ballasts are series wired. It is about 50/50, series to parallel when using electronic ballasts. With series wired ballasts, when one lamp is removed from the ballast the other lamp will not light properly and will fail if left running. The non- removed lamp will probably not light or will flicker or produce very little light. So, in a series wired ballast we need to remove all of the lamps from the ballast. The ballast will continue to use energy, 10 to 12 watts for magnetic and 1 to 2 watts for electronic. Parallel wired ballasts can be decamped without too many problems and are often rated by the manufacturer to run one less lamp than the label rating.

8.4.3 Task Lighting

Task lighting implies providing the required good illuminance only in the actual small area where the task is being performed, while the general illuminance of the shop floor or office is kept at a lower level; e.g. Machine mounted lamps or table lamps. Energy saving takes place because good task lighting can be achieved with low wattage lamps.

The concept of task lighting if sensibly implemented, can reduce the number of general lighting fixtures, reduce the wattage of lamps, save considerable energy and provide better illuminance and also provide aesthetically pleasing ambience. In some textile mills, lowering of tube light fixtures has resulted in improved illuminance and also elimination of almost 40% of the fixtures. The dual benefit of lower energy consumption and lower replacement cost has been realized. In some engineering industries, task lighting on machines is provided with CFLs. Even in offices, localised table lighting with CFLs may be preferred instead of providing a large number of fluorescent tube lights of uniform general lighting.

8.4.4 Selection of High Efficiency Lamps and Luminaries

Details of common types of lamps are summarized below. From this list, it is possible to identify energy saving potential for lamps by replacing with more efficient types.

Table 8.4 Information on Commonly Used Lamps

Lamp Type	Lamp Rating in Watts **(Total Power including ballast losses in Watts)**	Efficacy in **Lumens/Watt** (including ballast losses, where applicable)	Color **Renderin Index**	Lamp **Life**
General Lighting Service (GLS) (Incandescent bulbs)	15, 25, 40, 60, 75, 100, 150, 200, 300, 500 (no ballast)	8 to 17	100	1000
Tungsten Halogen (Single ended)	75, 100, 150, 500, 1000, 2000 (no ballast)	13 to 25	100	2000
Tungsten Halogen (Double ended)	200, 300, 500, 750, 1000, 1500 00, 2000 (no ballast)	16 to 23	100	2000
Fluorescent Tube lights (Argon filled)	20, 40, 65 (32, 51, 79)	31 to 58	67 to 77	5000
Fluorescent Tube lights	18, 36, 58 (29, 46, 70)	38 to 64	67 to 77	5000
Compact Fluorescent Lamps (CFLs) (without prismatic envelope)	5, 7, 9, 11, 18, 24, 36 (8,12,13,15,28,32,45)	26 to 64	85	8000
Compact Fluorescent Lamps (CFLs) (with prismatic envelope)	9, 13, 18, 25 (9, 13, 18, 25) i.e. rating is inclusive of ballast cons.	48 to 50	85	8000
Mercury Blended Lamps	160 (internal ballast, rating is inclusive of ballast consumption)	18	50	5000
High Pressure Mercury Vapour (HPMV)	80, 125, 250, 400, 1000, 2000 (93, 137, 271, 424, 1040, 2085)	38 to 53	45	5000
Metal Halide Lamps (Single ended)	250, 400, 1000, 2000 (268, 427, 1040, 2105)	51 to 79	70	8000
Metal Halide Lamps (Double ended)	70, 150, 250 (81, 170, 276)	62 to 72	70	8000
High Pressure Sodium Vapour Lamps (HPSV)	70, 150, 250, 400, 1000 (81, 170, 276, 431, 1060)	69 to 108	25 to 60	>1200 0
Low Pressure Sodium Vapour Lamps (LPSV)	35, 55, 135 (48,68,159)	90 to 133		

The following examples of lamp replacements are common.

- Installation of metal halide lamps in place of mercury / sodium vapour lamps. Metal halide lamps provide a high color rendering index when compared with mercury & sodium vapour lamps. These lamps offer efficient white light. Hence, metal halide is the choice for color critical applications where, higher illumination levels are required. These lamps are highly suitable for applications such as assembly lines, inspection areas, painting shops, etc. It is recommended to install metal halide lamps where color rendering is more critical.
- Installation of High Pressure Sodium Vapour (HPSV) lamps for applications where color rendering is not critical. High pressure sodium vapour (HPSV) lamps offer more efficacy. But the color rendering property of HPSV is very low. Hence, it is recommended to install HPSV lamps for applications such street lighting, yard lighting, etc.
- Installation of LED panel indicator lamps in place of filament lamps. Panel indicator lamps are used widely in industries for monitoring, fault indication, signaling, etc.

Conventionally filament lamps are used for the purpose, which has got the following disadvantages:

- High energy consumption (15 W/lamp)
- Failure of lamps is high (Operating life less than 10,000 hours)
- Very sensitive to voltage fluctuations

The LEDs have the following merits over filament lamps.

- Lesser power consumption (Less than 1 W/lamp)
- Withstand high voltage fluctuation in power supply.
- Longer operating life (more than 1,00,000 hours)

It is recommended to install LEDs for panel indicator lamps at the design stage.

The types of lamps used depends on the mounting height, color rendering may also be a guiding factor. The table below summarizes the replacement possibilities with the potential savings.

Table 8.5 Savings by Use of More Efficient Lamps

Existing Lamp	Replace by	Potential Energy Savings, %
GLS (Incandescent)	Compact Fluorescent Lamp (CFL)	38 to 75
	High Pressure Mercury Vapour (HPMV)	45 to 54
	Metal Halide	66
	High Pressure Sodium Vapour (HPSV)	66 to 73
	LED	85
Standard Tube light (Argon)	Slim Tube light (Krypton)	9 to 11
	LED Tube light	50
Tungsten Halogen	Tube light (Krypton)	31 to 61
	High Pressure Mercury Vapour (HPMV)	54 to 61
	Metal Halide	48 to 73

	High Pressure Sodium Vapour (HPSV)	48 to 84
	LED/Induction lamp	70-80
Mercury Blended Lamp	High Pressure Mercury Vapour (HPMV)	41
High Pressure Mercury Vapour (HPMV)	Metal Halide	37
	High Pressure Sodium Vapour (HPSV)	34 to 57
	Low Pressure Sodium Vapour (LPSV)	60
	LED/Induction lamp	60
Metal Halide	High Pressure Sodium Vapour (HPSV)	35
	Low Pressure Sodium Vapour (LPSV)	42
	LED/Induction lamp	30-35
High Pressure Sodium Vapour	Low Pressure Sodium Vapour (LPSV)	42

There may be some limitations if color rendering is an important factor. It may be noted that, in most cases, the luminaires and the control gear would also have to be changed. The savings are large if the lighting scheme is redesigned with higher efficacy lamps and luminaires.

Considerable development work is being done to improve the effectiveness of luminaires. For tube lights in dust-free areas, luminaires with mirror optics may be used in place of the conventional stove enamel painted trough type luminaires or recessed luminaires with acrylic covers. This measure is well accepted and has been implemented in a large number of offices and commercial buildings.

8.4.5 Reduction of Lighting Feeder Voltage

Figure 15 shows the effect of variation of voltage on light output and power consumption for fluorescent tube lights. Similar variations are observed on other gas discharge lamps like mercury vapour lamps, metal halide lamps and sodium vapour lamps; table below summarizes the effects. Hence, reduction in lighting feeder voltage can save energy, provided the drop in light output is acceptable. In many areas, night time grid voltages are higher than normal; hence reduction in voltage can save energy and also provide the rated light output. Some manufacturers are supplying reactors and transformers as standard products. A large number of industries have used these devices and have reported saving to the tune of 5% to 15%. Industries having a problem of higher night time voltage can get an additional benefit of reduced premature lamp failures.

Table 8.6 Variation in Light Output and Power Consumption

Particulars	10% lower voltage	10% higher voltage
	Fluorescent	
Light output	Decreases by 9%	Increases by 8%
Power input	Decreases by 15%	Increases by 8%
	HPMV	
Light output	Decreases by 20%	Increases by 20%
Power input	Decreases by 16%	Increases by 17%
	Mercury blended	
Light output	Decreases by 24%	Increases by 30%
Power input	Decreases by 20%	Increases by 20%
	Metal halide	
Light output	Decreases by 30%	Increases by 30%
Power input	Decreases by 20%	Increases by 20%

	HPSV	
Light output	Decreases by 28%	Increases by 30%
Power input	Decreases by 20%	Increases by 26%
	LPSV	
Light output	Decreases by 4%	Increases by 2%
Power input	Decreases by 8%	Increases by 3%

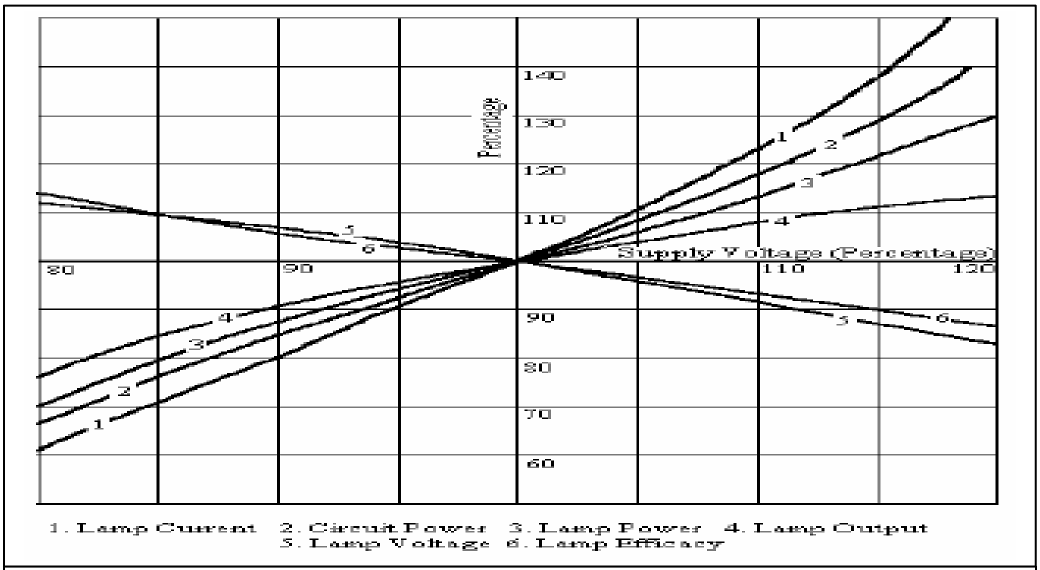


Figure 8.15. Effect of voltage variation of fluorescent tube light parameters

8.4.6 Electronic Ballasts instead of electromagnetic ballasts

Conventional electromagnetic ballasts (chokes) are used to provide higher voltage to start the tube light and subsequently limit the current during normal operation. *Electronic ballasts* are oscillators that convert the supply frequency to about 20,000 Hz to 30,000 Hz.

Industries have installed electronic ballasts for tube lights in large numbers. The operation is reliable, provided the ballasts are purchased from established manufacturers. Electronic ballasts have been developed for 20W, 40 W and 65W fluorescent tube lights, 9W & 11W CFLs, 35W LPSV lamps and 70W HPSV lamps. These are now commercially available.

Benefits of using electronic ballasts for fluorescent tube lights instead of electromagnetic ballasts are:

- Reduced power loss: only about 1 Watt, in place of 10 to 15Watts in standard electromagnetic chokes. Table 6 shows the approximate savings by use of electronic ballasts.
- Improved efficacy of tube lights at higher frequencies, resulting in additional savings if the ballast is optimized to provide the same light output as with the conventional choke. Hence a total saving of about 15 to 20 Watts per tube light can be achieved by electronic ballasts. The starter is eliminated and the tube light lights up instantly without flickering.

Table 8.7 Savings by use of Electronic Ballasts

Type of Lamp	With Conventional Electromagnetic ballast	With Electronic Ballast	Power Savings, Watts
40W Tube light	51	35	1
35W Low Pressure Sodium	48	32	1
70W High Pressure Sodium	81	75	6

8.4.7 Low Loss Electromagnetic Ballasts for Tube Lights

The loss in standard electromagnetic ballast of a tube light is likely to be 10 to 15 Watts. Use of *low loss electromagnetic chokes* can save about 8 to 10 Watts per tube light. The saving is due to the use of more copper and low loss steel laminations in the choke, leading to lower losses. A number of industries have implemented this measure

8.4.8 Timers, Twilight Switches & Occupancy Sensors

Automatic control for switching off unnecessary lights can lead to good energy savings. Simple timers or programmable timers can be used for this purpose. The timings may have to change, once in about two months, depending upon the season. Use of timers is a very reliable method of control.

Twilight switches can be used to switch the lighting depending on the availability of daylight. Care should be taken to ensure that the sensor is installed in a place, which is free from shadows, light beams of vehicles and interference from birds. Dimmers can also be used in association with photo-control. Dimmers are available for fluorescent tube lights as well as LEDs.

Infrared and *Ultrasonic occupancy sensors* can be used to control lighting in cabins as well as in large offices. Infrared occupancy sensors and ultrasonic occupancy sensors are available in market. It may be noted that more sophisticated occupancy sensors incorporate a microprocessor in each unit that continuously monitors the sensors, adjusting the sensitivity levels to optimize performance. The microprocessor is programmed to memorize the static and changing features of its environment; this ensures that the signals received from repetitive heat and motion equipment like fans is filtered out.
In developed countries, the concept of tube light fixtures with in-built electronic ballast, photo- controlled dimmer and occupancy sensor is being promoted as a package. The following control methodologies are useful.

General areas

- Where day lighting is available, provide day lighting controls. Use continuous dimming for spaces with minor motion activity such as reading, writing, and conferencing. Use stepped dimming (on/off switching) for spaces with major motion activity such as walking and shelf stocking.
- Always mount ultrasonic occupancy sensors at least 6 to 8 ft. away from HVAC ducts on vibration free surfaces and place so there is no detection out the door or opening of the space.

- In spaces of high occupant ownership such as private offices and conference rooms, always include switches for manual override control of the lighting.
- If there is concern that lighting could be turned off automatically or manually when people are still in the space, put in night lighting for safe egress.
- Many lighting control devices have specific voltage and load ratings requirements. Be sure to specify the device model that matches the correct voltage and load rating for the application.

Conference Rooms

- Use dual technology occupancy sensors in larger conference rooms for optimal detection of both small hand motion and larger body movement.
- Ceiling or corner-mounted passive infrared occupancy sensors are used for medium and small conference rooms.
- Always include switches that provide manual override control of the lighting.

Cubicles

- Control plug loads such as task lighting, computer monitors, portable fans and heaters with an occupancy sensor controlled plug strip.
- Mount a personal occupancy sensor beneath binder bin or desk and position so that it cannot detect motion outside the cubicle area.

Restrooms

- Use ceiling mounted ultrasonic sensors for restrooms with stalls.

Exterior Lighting Control

- Use a lighting control panel with time clock and photocell to control exterior lighting to turn on at dusk and off at dawn and turn non-security lighting off earlier in the evening for energy savings.

8.4.9 T5 Fluorescent Tube Light

The commonly used fluorescent tube lights are T12 (40W) and T8 (36W). T12 implies that the tube diameter is 12/8" (33.8mm), T8 implies diameter of 8/8" (26mm) and T5 implies diameter of 5/8" (16mm). This means that the T5 lamp is slimmer than the 36W slim tube light.

The efficiency of the 35W T5 lamp is about 104 lm/W(lamp only) and 95 lm/W (with electronic ballasts), while that of the 36W T8 lamp is about 100 lm/W (lamp only) and 89 lm/W (with electronic ballast). This may appear to be a small improvement of about 7%, but with the use of super-reflective aluminum luminaire of higher efficiency, T5 lamps can effect an overall efficiency improvement ranging from 11% to 30%.

T5 lamps have a coating on the inside of the glass wall that stops mercury from being absorbed into the glass and the phosphors. This drastically reduces the need for mercury from about 15 milligrams to 3 milligrams per lamp. This may be advantageous in countries with strict waste disposal laws.

However, these lamps are about 50mm shorter in length than T12 and T8 lamps, which implies that the existing luminaires cannot be used. In addition, T5 lamp can be operated only with electronic ballast.

In Europe, the T5 lamps are being used in good numbers in place of 4 foot, 36W T8 lamps. Their shorter lengths permit integration in standard building modules. With new miniature ballasts, luminaires are light and flat, saving space and also resources used for their production. The USA has been slow in accepting this technology, as the 4 foot, T8 lamps consume only about 35 Watts. The focus in the USA has generally been on better optic control, rather than on lamp efficiency.

8.4.10 Lighting Maintenance

Maintenance is vital to lighting efficiency. Light levels decrease over time because of aging lamps and dirt on fixtures, lamps and room surfaces. Together, these factors can reduce total illumination by 50 percent or more, while lights continue drawing full power.

The following basic maintenance suggestions can help prevent this.

- Clean fixtures, lamps and lenses every 6 to 24 months by wiping off the dust.
- Replace lenses if they appear yellow.
- Clean or repaint small rooms every year and larger rooms every 2 to 3 years. Dirt collects on surfaces, which reduces the amount of light they reflect.

- Consider group re-lamping. Common lamps, especially incandescent and fluorescent lamps, lose 20 per cent to 30 per cent of their light output over their service life.

- Many lighting experts recommend replacing all the lamps in a lighting system at once. This saves labor, keeps illumination high and avoids stressing any ballasts with dying lamps.

8.5 Option Checklist

This section includes the most important energy efficiency options

- Reduce excessive illumination levels to standard levels using switching, delamping, etc. (Know the electrical effects before doing delamping.)
- Aggressively control lighting with clock timers, delay timers, photocells, and/or occupancy sensors.
- Install efficient alternatives to incandescent lighting, mercury vapor lighting, etc. Efficiency (lumens/watt) of various technologies range from best to worst approximately as follows: low pressure sodium, high pressure sodium, metal halide, fluorescent, mercury vapor, incandescent.
- Select ballasts and lamps carefully with high power factor and long-term efficiency in mind. obsolete fluorescent systems to Compact fluorescents and electronic ballasts
- Consider lowering the fixtures to enable using less of them.
- Consider day lighting, skylights, etc.
- Consider painting the walls a lighter color and using less lighting fixtures or lower wattages.
- Use task lighting and reduce background illumination.
- Re-evaluate exterior lighting strategy, type, and control. Control it aggressively.
- Change exit signs from incandescent to LED.

8.6 References

This module is largely adapted from the *Energy Efficiency Guide for Industries in India, Electrical Energy Equipment: Cooling Towers*
Other references sourced include:

CIE (Commission International de l'Eclairage) and IES (Illuminating Engineers Society) *Designing with Light- A lighting Handbook* - Anil Walia-International Lighting Academy *Handbook of Functional requirements on Industrial Buildings- SP-32*- Bureau of Indian

Standards. IS 3646 (Part I): 1992

Efficient Use of Electricity in Industries- Devki Energy Consultancies Pvt. Ltd., Vadodara

Energy Audit Reports of the National Productivity Council

Websites / Product Information CDs of the following manufacturers:

- Crompton Greaves Lighting Division
- Bajaj Electricals
- GE lighting, USA
- Watt Stopper Inc, USA
- Vergola India Ltd
- Lighting Research Centre, USA
- LBNL , USA

Chapter 9 Energy Conservation in Buildings

9.1 Introduction

Major energy consumption in building is in the form of lighting, space conditioning, power for various appliances and equipment and for water pumping. Depending upon the climatic zone, space conditioning would include heating or cooling or both. Energy consumption for space conditioning generally accounts for the major share of daily energy consumption. However in certain buildings depending upon the climatic zones, lighting load might be higher than space conditioning.

9.2 Energy Conservation Building Codes

The Energy Conservation Building Codes were developed as an addendum to the Building Code of Pakistan by the National Energy Conservation Centre (ENERCON). This Code gives minimum performance standards for building windows and openings, heating, ventilating and air- conditioning (HVAC) equipment and lighting. The standards have been developed for all five climatic zones into which Pakistan is divided. Figure 9.1 shows the map of Pakistan with minimum and maximum temperatures for all 5 zones.

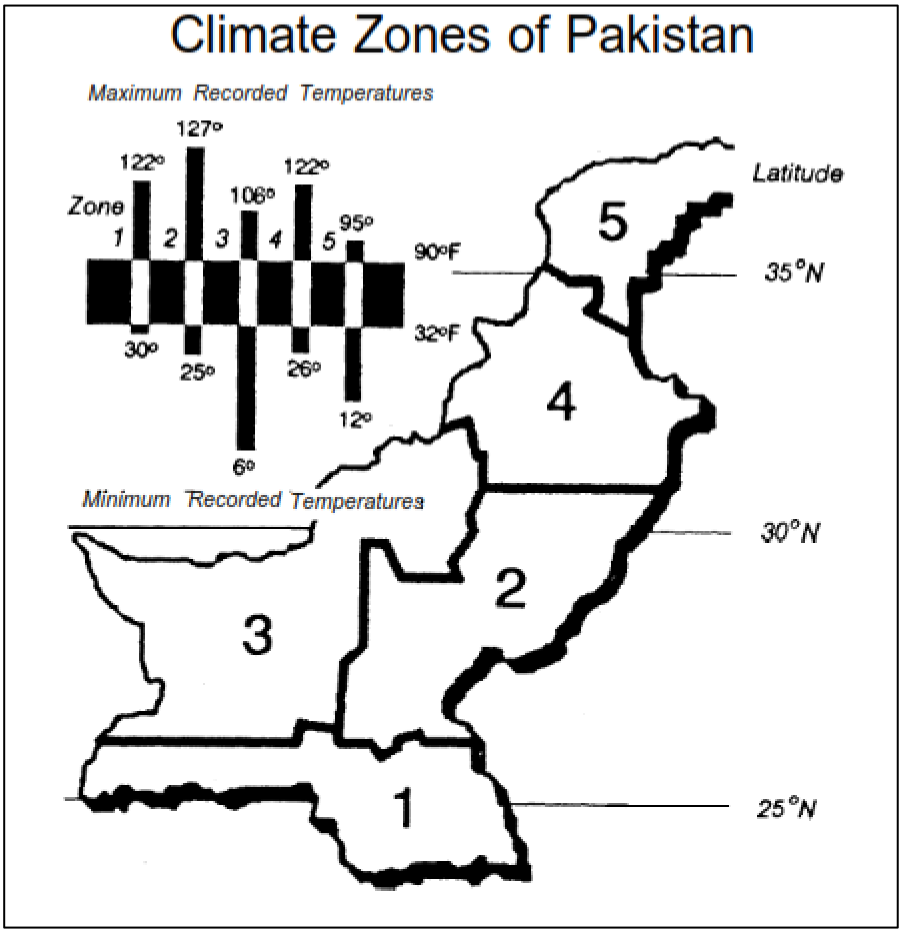


Figure 9.1: Climatic zones of Pakistan (Source: Pakistan Energy Conservation Building Codes)

The towns and cities under each climatic zone are given in Table 9.1.

Table 9.1: Towns and cities of Pakistan under each climatic zone (Source: Pakistan Energy Conservation Building Codes)

Zone 1	Zone 2	Zone 3	Zone 4	Zone 5
Badin	Bhawalnegar	Bela	Abbottabed	Chitral
Cauadar	Bhawalpur	Kalat	Bhakkar	Dir
Hyderabad	Chichawatni	Kharan	Bhalwal	Dassu
Jiuani	Chunian	Khuzdar	Chiniot	Gilgit
Karachi	Dadu	Loralai	Chakwal	Saidu Sharif
Mirpur Khan	D.G.Khan	Muslim Bagh	Charsada	Skardu
Pasni	Hasi Ipur	Nushki	Daska	
Sanghar	Jacobabed	Pan j gur	Faisalabed	
Thatta	Kabiruala	Pishin	Fateh Jeng	
Turbat	Kandiaro	Quetta	Gojra	
Uthal	Kashmore	Zhob	Gujranwala	
	Khai rpur		Guj rat	
	Khanewal		Hafizabad	
	Khanpur		Hassansbdal	
	Larkana		Haripur	
	Leiah		Islamabad	
	Lodhran		Jaranwala	
	Moro		Jauherabed	
	Multan		Jhang	
	Mazaffargarh		Jhellum	
	Nauabshah		Kasur	
	Okara		Kharian	
	Pak Pattan		Khushab	
	Rajanpur		Kohat	
	Rahimyar Khan		Lahore	
	Sadiqabad		Mansehra	
	Sahiwal		Mardan	
	Shi Karpur		Mianwali	
	Shorkot		Mirpur	
	Sibi		Muzzafarabad	
	Sujawal		Narowa 1	
	Sukkur		Noshera	
	Toba Tek Sing		Pasrur	
	Vihari		Peshawar	
			Rawalpindi	
			Samundri	
			Sargodha	
			Shakargarh	
			Sialkot	
			Swabi	
			Talagang	
			Tangi	
			Wah	
			Wazirabad	

9.3 ECBC Guidelines on Building Envelope

The ECBC guidelines on building envelope provide the minimum energy conservation requirements for the building envelope. In addition to the criteria set forth in this section, the proposed design should consider energy conservation in determining the orientation of the building on its site; the geometric shape of the buildings: the building aspect ratio (ratio of length to width); the number of stories for a given floor area requirement; the thermal mass of the building; the exterior surface color; shading or reflections from adjacent structures, surrounding surfaces or vegetation; opportunities for natural ventilation: and wind direction and speed.

For the purpose of meeting the requirements of this code, the building envelope shall comply with both the conduction (U0 and R) requirements and the Overall Thermal Transfer Value (OTTV) requirements as set forth in the code.

9.3.1 Conduction (U0 and R) Requirements

A roof assembly shall be considered as all components of the*roof/ceiling envelope through which heat flows, thus creating a building transmission heat loss or gain, where such assembly is exposed to outdoor air. The gross area of a roof assembly consists of the total exterior surface of such assembly (except for return air plenums, noted below), including skylights.

Where return air ceiling plenums are employed, the roof/ceiling assembly shall:

a. for thermal transmittance purposes, not include the ceiling proper nor the plenum space as part of the assembly, and

b. for gross area purposes, be based upon the interior face of the upper plenum surface.

The gross area of exterior walls measured on the exterior surface consists of all opaque wall areas (including foundation walls, between floor spandrels, peripheral edges of floors, etc.), window areas (including sash), and door areas.

The design of buildings for energy conservation may increase the water vapor pressure differentials between the interior and exterior environments. Vapor retarders, air infiltration and operating interior relative humidity should be considered to maintain the thermal and moisture integrity of the envelope (see ASHRAE Handbook 1989 Fundamentals).

U-values and R-values shall be calculated in accordance with the Building Energy Code Compliance Handbook or ASHRAE Handbook, 1989 Fundamentals.

9.3.1.1 Roofs/Ceilings

The thermal transmission value for the gross area of the roof shall not exceed the value given in Table 2.0. As an alternative, Equation 1 and Equation la can be used to determine acceptable combinations of U-values for different sections of the gross roof area, including skylights, hatches, etc. To meet this requirement, insulation materials may be placed either above, below or within the roof deck.

Equation 1:

$$U_0 = \frac{U_{r1} \times A_{r1} + U_{r2} \times A_{r2} + \cdots + U_{rn} \times A_{rn}}{A_{r1} + A_{r2} + \cdots + A_{rn}}$$

Where, U_0 = Overall thermal transmittance of the gross area of the roof (W/m^2°C)

U_{r1}, U_{r2}, U_{rn} = Respective thermal transmittance of different roof sections (W/m^2°C)

A_{r1}, A_{r2}, A_{rn} = Respective areas of different roof sections (m^2)

Equation 1A

Where skylight/glazing is used on the roof, the thermal transmittance for the gross area of the roof should be determined from

$$U_0 = \frac{U_r \times A_r + U_g \times A_g}{A_0}$$

Where, U_0 = Overall thermal transmittance of gross roof area (W/m^2°C)

U_r = Thermal transmittance of components of opaque roof area (W/m^2°C)

A_r = Opaque roof area (m^2)

U_g = Thermal transmittance of glazing area (W/m^2°C)

A_g = Glazing area (m^2)

A_0 = gross area of exterior roof (m^2)

Where more than one type of roof ceiling and or skylight is used, the Ur term for that exposure shall be expanded into sub elements as:

$$U_{r1} \times A_{r1} + U_{r2} \times A_{r2} \ldots$$

9.3.1.2 Surfaces Separating Conditioned and Unconditioned Spaces

For surfaces that separate conditioned and unconditioned space, the U0 value shall not exceed the value given in Table 9.2.

9.3.1.3 Walls

The gross wall area above grade shall have thermal, transmission value, U0 not exceed the values in Table 9.2. Equation 2 shall be used to determine the acceptable combinations to meet these requirements. There are no thermal requirements for wall sections below grade.

Table 9.2: Allowable conductance and resistance values*

Element	Symbol	Unit	1	2	3	4	5
Walls	U_0	W/m^2	2.67	2.56	2.22	2.50	2.22
		Btu/hft^2	0.47	0.45	0.39	0.44	0.39
Roofs/Ceilings	U_0	W/m^2	0.58	0.58	0.58	0.58	0.58
		Btu/hft^2	0.1	0.1	0.1	0.1	0.1
Shaded roofs and floors exposed to weather**	U_0	W/m^2	1.16	1.16	1.16	1.16	1.16
		Btu/hft^2	0.20	0.20	0.20	0.20	0.20
Floors unheated space	U_0	W/m^2	2.27	1.70	1.42	1.70	1.42
		Btu/hft^2	0.40	0.30	0.25	0.30	0.25
Heated Slab on Grade	R	W/m^2	0.44	0.63	0.74	0.67	0.74
		Btu/hft^2	2.50	3.60	4.20	3.60	4.20

*U_0 values listed are maximum,
R values listed are minimum values

**If an air space exists between the roof end ceiling, and the space is well ventilated, the ceiling is considered shaded (provided insulation is placed on the ceiling)

Equation 2

$$U_0 = \frac{U_w \times A_w + U_g \times A_g + U_d \times A_d}{A_0}$$

Where, U_0 = the overall thermal transmittance of the gross wall area (W/m^2°C)
A_0 = gross area of the exterior surface above grade (m^2)
= $A_w+A_g+A_d$
Aw= Opaque wall area (m^2)
Uw=Thermal transmittance of the components of the opaque wall (W/m^2°C)
Ag = Glazing area (m^2)
Ug=Thermal transmittance of the glazing area (W/m^2°C)
Ad = Door area (m^2)
Ug=Thermal transmittance of door area (W/m^2°C)

Where more than one type of wall, window and/or door is used, the U&A terms for these items shall be expanded into sub elements as:

$$U_{w1} \times A_{w1} + U_{w2} \times A_{w2} + \cdots$$

9.9.3 Overall Thermal Transfer Value (OTTV) Requirements

The cooling design criterion for walls, floors and roof/ceilings is known as the Overall Thermal Transfer Value (OTTV). It is aimed at achieving the design of a building envelope that adequately reduces heat gain by both conduction and solar radiation in order to reduce the cooling load of the air conditioning system. The cooling design criterion for walls, floors and roof/ceilings is to be known as the Overall Thermal Transfer Value (OTTV). It is aimed at achieving the design of a building envelope that adequately reduces heat gain by both conduction and solar radiation in order to reduce the cooling load of the air conditioning system. The OTTV concept is based on the three basic methods of heat gains through envelop of a building

- Heat conduction through opaque walls, roofs/ceiling and floor
- Heat conduction through windows and/or skylights
- Solar radiation through windows and/or skylights

The OTTV calculation shall be for all climate zones (shown in Appendix I) of Pakistan and shall not exceed the values given in Table 9.3.

9.3.3.1 Equivalent Temperature Difference

Solar radiation on the building is a cyclic heat input. The outdoor air temperature also varies during the 24 hr period in a day. The Equivalent Temperature Difference (TDeq) concept shall be adopted so that the variable heat flow through the envelope may be calculated using the steady heat flow equation:

$$q = A \times U_0 \times TD_{eq}$$

The TDeq across the envelope takes into account the types of construction (mass and density), degree of exposure, time of the day, location, and orientation and design conditions. For simplicity in OTTV calculations, the TDEq of different types of construction have been simplified and should be the values as follows:

TDeq for Walls:

$$TD_{eq}(°C) = 26.7 - 0.0371Wt$$

Where, Wt is in kg/m^2

$$TD_{eq}(°F) = 48.0 - 0.3257W_t$$

Where, Wt is in lb/ft^2

Table 9.3: TDeq for ceiling/roof

U/TC(1/s)	**0.36**	**0.42**	**0.48**	**0.54**	**0.60**	**0.96**	**1.32**	**1.68**	**2.04**	**2.40**	**6.00**
TDeq (°C)	16.7	19.5	22.2	25.0	27.8	30.6	33.3	36.1	30.9	41.7	44.4
U/TC(1/hr)	0.006	0.007	0.008	0.009	0.010	0.016	0.022	0.028	0.034	0.040	0.10
TDeq (°F)	30.0	35.0	40.0	45.0	50.0	55.0	60.0	65.0	70.0	75.0	80.0

$$TC = Specific\ heat \times Density \times Thickness$$

$$TC = (\frac{kJ}{kg°C}) \times (\frac{kg}{m3}) \times \frac{m}{1000}$$

9.3.3.2 Solar Factor

The OTTV calculations require a solar factor for glazing areas. The solar factor value for vertical surfaces for Pakistan should be taken as specified in Table 9.4. For a given orientation the solar factor may be taken from the following:

Table 9.4: Solar factors for Walls and Roofs W/m^2 (Btu/hFt^2)

	Orientation					
Climate		NE	E	SE		
Zone	N	NW	W	SW	S	Roof
1	117	450	561	350	135	471
	(37)	(143)	(178)	(111)	(43)	(150)
2	110	432	561	378	167	471
	(35)	(137)	(178)	(120)	(53)	(150)
3	110	432	561	378	167	471
	(35)	(137)	(178)	(120)	(53)	(150)
4	104	422	558	410	217	471
	(33)	(134)	(177)	(130)	(69)	(150)
5	104	416	558	425	252	471
	(33)	(132)	(177)	(135)	(80)	(150)

9.3.3.3 Overall Thermal Transfer Value (OTTV)

For the purpose of energy conservation, the maximum permissible OTTV shall be as per Table 9.5 for walls and ceilings/roofs.

Table 9.5 Maximum Overall Thermal Transfer Values

CLIMATE ZONE*	WALLS		ROOFS	
	W/m²	Btu/hr.ft²	W/m²	Btu/hr.ft²
1	91	29	26.8	8.5
2	95	30	26.8	8.5
3	95	30	26.8	8.5
4	98	31	26.8	8.5
5	101	32	26.8	8.5

To calculate the OTTV for external walls, the following formula shall be used:

$$OTTV_W = \frac{\left(U_w \times A_w \times TD_{eq}\right) + \left(A_f \times SF \times SC\right) + \left(U_g \times A_g \times T\right)}{A_0}$$

Where,

$OTTV_w$ = Overall thermal transfer Value for walls (W/m^2)

A_w = Opaque wall area (m^2)

U_w = Thermal transmittance of opaque wall (W/m^2°C)

TD_{eq} = Equivalent temperature difference (°C)

A_g = Area of glazing (m^2)

U_g= Thermal transmittance of glazing (W/m^2°C)

T = Temperature difference between interior and exterior design condition (°C)

SC = Shading co-efficient of fenestration

SF = Solar/Corrected Solar factor

A_0 = Gross area of the exterior surface (m^2)

Where there is more than one type of material and/or fenestration the respective term or terms shall be expanded into sub elements.

$$\left(U_{w1} \times A_{w1} \times TD_{eq1}\right) + \left(U_{w2} \times A_{w2} \times TD_{eq2}\right) + \cdots$$

The gross area of the exterior wall shall include all opaque wall areas, window areas and door areas where such surfaces are exposed to outdoor air and enclose conditioned space. The fenestration area shall be measured from extreme surfaces of window construction.

To calculate the OTTV of a roof, the following formula is used:

$$OTTV_r = \frac{\left(U_r \times A_r \times TD_{eq}\right) + \left(A_s \times SF_s \times SC\right) + \left(U_s \times A_s \times T\right)}{a}$$

Where,

OTTVr = Overall thermal transfer Value for roof (W/m^2)

Ar = Opaque roof area (m^2)

U_w = Thermal transmittance of opaque roof (W/m^2°C)

TD_{eq} = Equivalent temperature difference (°C)

A_s = Skylight area(m^2)

U_s= Thermal transmittance of skylight (W/m^2°C)

T = Temperature difference between interior and exterior design condition (°C)

SC = Shading co-efficient of fenestration
SF = Solar/Corrected Solar factor
a = Gross area of the exterior surface (m^2)

The gross area a, shall include all opaque roof area and skylight area where such surfaces are exposed to outdoor air and enclose conditioned space.

Walls at different orientations and roofs consisting of different sections facing different orientations receive different amount of solar radiation. To calculate the OTTV for the envelope of the whole building, it is necessary to compute first the OTTVs of individual walls, then the OTTV of the whole building is obtained by weighted average values.

$$OTTV_w = \frac{(OTTV_{w1} \times A_{w1}) + (OTTV_{w2} \times A_{w2})}{A_{w1} + A_{w2} + \cdots}$$

Similarly for roof

$$OTTV_r = \frac{(OTTV_{r1} \times A_{r1}) + (OTTV_{r2} \times A_{r2})}{A_{r1} + A_{r2} + \cdots}$$

The OTTV of walls should not be computed with that of roof. Each component should be treated separately.

9.3.4 Air Infiltration

To minimize the effects of air infiltration, all doors and openable sections of windows of air conditioned buildings shall be weather stripped. All fixed window sections and other penetrations through the wall shall be caulked or otherwise sealed with a permanent material, for air-conditioned buildings.

9.3.5 Natural Ventilation

Natural ventilation should be designed for effective ventilation regardless of wind direction. There should be adequate ventilation when the wind does not come from the prevailing direction. To obtain adequate air flow and velocity inside the buildings, the position of the openings relative to wind direction and the position and size of openings in adjacent or opposite walls should be carefully designed. The minimum area of windows which must be openable for the purpose of natural ventilation is provided in Table 9.6.

Table 9.6: Minimum openable window area for natural ventilation

Location	Opening
Residential (Bedroom, Drawing room, Dining Room and Kitchen)	50%
Water closet, toilet, bathroom, laundry etc.	100%
Stairs, utility etc.	50%
Corridors	50%

Wherever ceiling fans are used for cooling they should be of the blade diameter recommended in the Building Code of Pakistan, Table 9.6.Whole house fans may be used for the purpose of ventilation and cooling. Where these are provided, they should be sized to provide a minimum of 20 air changes per hour for the entire house.

9.4 Heating Ventilation and Air Conditioning in ECBE

This section provides the minimum requirements for design, sizing and control of space conditioning by heating, cooling and ventilation equipment.

9.4.1 System Design:

System design consists of proper sizing of the system transport of energy. For the purpose of sizing HVAC systems, the heating and cooling design loads include sensible and latent heat gain and loss from conduction, solar radiation, infiltration, ventilation and internal loads.

As per the ECBC guidelines,

- Recovered energy in excess of the new energy expended in the recovery process may be used for the control of temperature and humidity.
- For systems employing reheating and servicing multiple zones, controls should be provided to automatically reset the system cold air supply to the highest temperature level that will satisfy the zone requiring the coolest air.
- For dual duct and multi zone systems, automatic controls to be provided that will reset the cold deck air supply to the highest temperature that will satisfy the zone requiring the coolest air and the hot deck air supply to the lowest temperature that will satisfy the zone requiring the warmest air
- Systems in which heated air is re-cooled, directly or indirectly, to maintain space temperature should be provided with control that will automatically reset the temperature to which the supply air is heated to the lowest- level that will satisfy the zone requiring the warmest air.
- For systems with multiple zones, one or more zones may be chosen to represent a number of zones with similar heating/ cooling characteristics.
- Where concurrent operation of independent heating and cooling systems serving common spaces is required, sequential temperature control to be provided for both heating and cooling capacity in each zone. In addition, heat energy input to be limited through automatic reset control of the heating medium temperature (or energy input rate) to only that necessary to offset heat loss due to transmission and infiltration and, where applicable, to heat the ventilation air supply to the space.

9.4.2 Temperature Controls

- Adjustable thermostat to be provided for temperature control and should be capable of being set from 13 to 29°C wherever heating and cooling are used. As per ECBC norms, recommended internal dry bulb temperature shall be 26°C for summers and 21°C for winters.
- If humidity control is provided, humidistat should be provided and it should be capable to prevent use of more than 30% energy for maintaining humidity.
- At least one thermostat to be provided for each separate system and separate zone
- Electrical or mechanical devices (eg. dampers) to be provided to reduce the energy consumption for heating/cooling
- Insulated ducts and pipelines to be provided for HVAC systems

9.4.3 System and component efficiency

The energy efficiency ratio (EER) of the equipment and the coefficient of performance (C.0.P) for heating, ventilating and air conditioning systems are given in Table 9.7.

Table 9.6: Minimum COP/ERR cooling (performance at sea level)

Standard Rating Capacities	COP	ERR
19kW (65,000 Btu/h) and above		
• Air Cooled	2.40	8.2
• Evaporation or Water Cooled	2.69	9.2
Under 19kW (65,000 Btu/h)		
• Air Cooled	2.28	7.8
• Evaporation or Water Cooled	2.58	8.8

COP of heat operated equipment is given in Table 9.8.

Table 9.8 Efficiency of Heat Operated Equipment

Heat Source	Minimum COP*
Gas Fired Engine	1.25
Direct Fired (Gas, Oil)	0.48
Indirect Fired (Steam, Hot Water)	0.68

$$* \, Minimum\ COP = \frac{Net\ Cooling\ Output}{Total\ Heat\ Input}$$

(Electrical auxiliary inputs excluded)

9.4.4 Combustion Efficiency

Combustion efficiency of residential furnaces and boilers is defined as 100 percent minus stack losses in percent of heat input. Stack losses are:

- Loss due to incomplete combustion
- Loss due to sensible heat and latent in moisture formed by combustion of hydrogen in fuel.

The required efficiency of combustion equipment is given in Table 9.8.

Table 9.8: Efficiency of combustion equipment

Type of equipment	Residential/Commercial Furnace with inputs 65.9kW(225,000 Btu/h) and less and Boilers with inputs 87.8kW(300,000 Btu/h) and less	All other commercial & industrial Furnace and Boiler
Forced Air Furnace	75	75
Low Pressure Steam or Hot Water Boiler	80	80
Gravity Central Furnaces	69	-
All other vented heating equipment	69	-

9.5 ECBC Guidelines on Lighting

- The ECBC guidelines specifies the minimum efficacy of various type of guidelines, However only Fluorescent lamps, Fluorescent Tube Lights, Mercury Vapour lamps, Sodium Vapour lamps and Metal Halides are covered. The most energy efficient LEDs and induction lamps have not been covered.
- The use of mirror reflectors or prismatic reflectors is recommended for high pressure discharge lamps.
- Automatic timers and sensors are to be provided to ensure savings during daylight hours.
- Daylight is the most efficient and economical light source and the cost is limited only to the construction and maintenance of windows. However while making use of daylight, it should be ensure that proper glazing id provided, along with sun shading wherever required
- The quantity of daylight in an interior area can be specified by the "Daylight Factor". It is the ratio of the illuminance at a point inside to the illuminance on an unobstructed horizontal plane outside under a specified distribution of sky luminance, direct sunlight being excluded from both measurements.
- Instead of a common switch, it is recommended to have individual switching for a small group of lights to allow unnecessary lights to be switched OFF. While designing of the lighting controls, following points are to be considered:
  - Lighting in task areas larger than 10m2 shall be provided with controls so that the lighting can be reduced by at least half when the task is not performed or relocated.
  - Except for enclosed stairways and corridors used by the public, switches should be provided at accessible locations within sight of the light they control.
  - Where lighting switches are grouped, they should be suitably identified to indicate the area controlled by each switch.
  - Luminaires should be switched in row parallel to the windows, so that the rows of lights near to the windows can be turned off (manually or automatically) when daylighting is adequate.
  - Where task lighting is installed, such lighting should be provided with switches located adjacent to the work station

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Book 4:
Energy Performance Assessment
of
Different Industrial Sectors

Guide Book
For
National Certification Examination for
Energy Auditors and Managers

National Energy Efficiency and Conservation Authority

Acknowledgements

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One of the main tasks of the project was the finalization of syllabus, and course modules including the development of model question banks for examination processes. This task was entrusted to a consortium of experts from two organizations, namely The Energy and Resources Institute (TERI) India, and PITCO from Pakistan.

This Book covers details of energy performance assessment of thermal power plants, cement plants, textile plants, pulp and paper industries and steel re-rolling mills.

The members of consortium would like to express their gratitude:

- to UNIDO, to the National Energy Efficiency and Conservation Authority (NEECA), and to CTCN for the unconditional support and advice they have provided them with during the whole duration of their study;
- to the local key stakeholders who were involved throughout the whole process of the study for their comments and their invaluable contributions during the consultation meetings (held in Islamabad and Lahore) and the workshop held in Islamabad in August 07, 2019.

Their comments and feedback helped the consultants to make sure that the recommendations made were the most appropriate and fair in terms of benefits to the project developers, the government and other relevant partners.

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Chapter 1 Energy Performance Assessment of Thermal Power Plants

1.1 Introduction

Pakistan has an installed electricity generation capacity of 33,836 MW in 2018. Major power generation share is by thermal power plant (63%) and remaining by hydro (27%), Renewable (Solar & Wind 5%) and nuclear (5%). Thermal power plant further sub-divided based on fuel used such as Furnace oil (16%), Natural gas (12%), LNG (26%), Coal (9%).

Thermal power plants (plants operating on carbon-based fuel such as coal, natural gas and petroleum products) are categories as follows,

a. **Steam turbine power plants** produce electric power by creating steam at high pressure and temperature in boilers, which is then expanded through a steam turbine causing the turbine to drive a generator which then produces electric power. The steam turbine follows the Rankine Cycle.

b. **Simple cycle gas turbine plants** are plants that follow the Brayton Cycle. In these gas turbines, the air is compressed in the compressor section of the turbine to high pressure and temperature, and fed in the combustor. The air is used to burn fuel at high temperature at constant pressure. The flue gas leaving the combustor is at high pressure and temperature and is then expanded through the turbine section; this drives a generator that produces electric power.

c. **Combined cycle power plants** are associated with electrical power plants, which use the waste heat from the prime mover for the production of steam, and consequently, the steam is used in a steam turbine for the production of additional power. This is usually a combination of the Brayton Cycle (gas turbine) as the topping cycle and the Rankine Cycle (steam turbine) as the bottoming cycle. Many small plants use the Diesel Cycle as the topping cycle, with the Rankine Cycle as the bottoming cycle. Plants are also using the Brayton Cycle (gas turbine) as both the topping and the bottoming cycles.

d. **Cogeneration** is the production of two or more forms of energy from a single plant. The most common application of the term is for the production of electrical power and steam for use in process applications. Also, cogeneration plants are used to produce power and use the direct exhaust gases from the prime movers for preheating air in furnaces, for absorption cooling systems (VAM), or for heating various types of fluids in different process applications. Cogeneration system often used in petrochemical plants where the prime mover drives are used to drive compressors to compress process gasses and then the heat used to either produce steam for process use or direct use in processes.

1.2 Open and combined cycle power plants

1.2.1 Gas turbine (Open cycle)

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are composed of three main components: compressor, combustor and power turbine. In the compressor section, air is drawn in and compressed up to 30 time's ambient pressure and directed to the combustor section where fuel is introduced, ignited and burned. The heated gases coming out of the combustion chamber are then passed through the turbine where it expands doing mechanical work. Some part of the power developed by the turbine is utilized in driving the compressor and other accessories and remaining are used for power generation. Fresh air enters into the compressor and gases coming out of the turbine are exhausted into the atmosphere. This type of cycle is known as an open cycle gas turbine plant. Schematic of an open cycle gas turbine is given in figure 1.1.

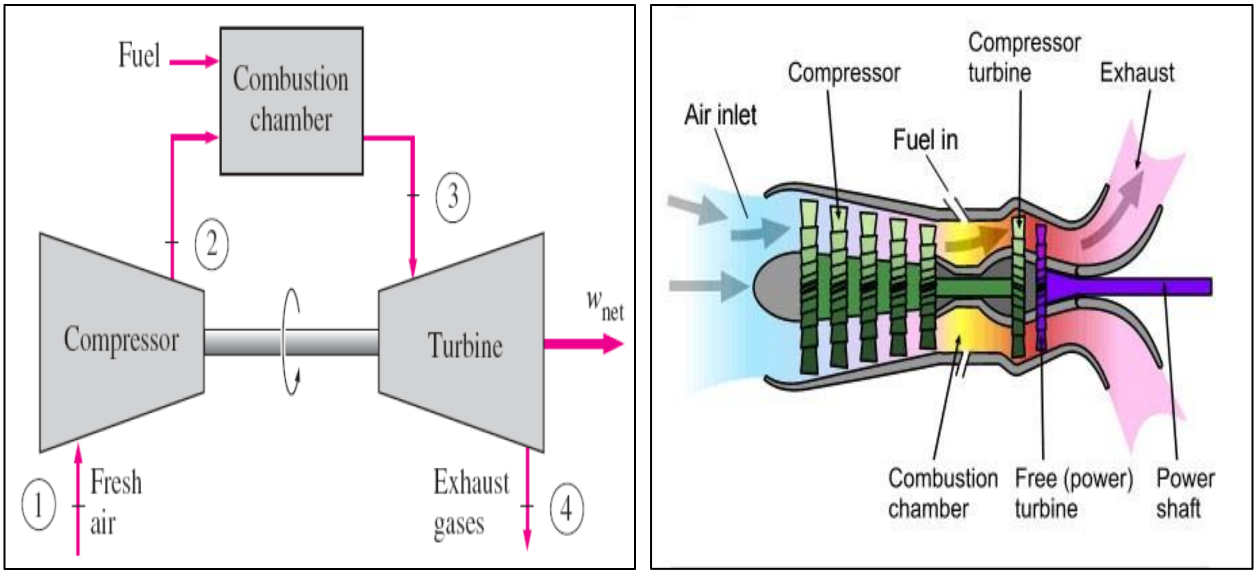


Figure 1.1 Open cycle gas turbine

The simple cycle gas turbine is classified into three groups: industrial type, aeroderivative gas turbines, and frame type. The industrial-type gas turbine varies in range from about 500 to 15,000 kW. This type of turbine has been used extensively in many petrochemical plants and the source of remote power. The efficiency of these units are in the low 30s. Aeroderivative, as the name indicates, are power generation units, which have origin in the aerospace industry as the prime mover of aircraft. These units have been adapted to the electrical generation industry by removing the bypass fans and adding a power turbine at their exhaust. These units range in power from 2.5 to about 50 MW. The efficiency of these units can range from 35% to 42%. The frame units are the large power generation units ranging from 3 to 350 MW in a simple cycle configuration, with efficiency ranging from 30% to 43%.

Advantages of Open Cycle:

1. Warm-up time: Once the turbine is brought up to the rated speed by the starting motor and the fuel is ignited, the gas turbine will be accelerated from cold start to full load without warm-up time.
2. Low weight and size: The weight in kg per kW developed is less.
3. Fuels: Almost any hydrocarbon fuel from high-octane gasoline to heavy diesel oils can be used in the combustion chamber.
4. Open cycle plants occupy less space compared to close cycle plants.
5. The stipulation of a quick start and take-up of load frequently are the points in favour of open cycle plant when the plant is used as a peak load plant.
6. Component or auxiliary refinements can usually be varied in open cycle gas turbine plant to improve the thermal efficiency and can give the most economical overall cost for the plant load factors and other operating conditions envisaged.
7. Open cycle gas turbine power plant, except those having an inter-cooler, does not need cooling water. Therefore, the plant is independent of the cooling medium and becomes self-contained.

Disadvantages of Open Cycle:

1. The part-load efficiency of the open cycle gas turbine plant decreases rapidly as the considerable percentage of power developed by the turbine is used for driving the compressor.
2. The system is sensitive to the component efficiency; particularly that of compressor. The open cycle gas turbine plant is sensitive to changes in the atmospheric air temperature, pressure and humidity.
3. The open cycle plant has high air rate compared to the closed cycle plants, therefore, it results in increased loss of heat in the exhaust gases and large diameter duct-work is needed.
4. The dust must be prevented from entering into the compressor to decrease erosion and depositions on the blades and passages of the compressor and turbine. So damages their profile. The deposition of the carbon and ash content on the turbine blades is not at all desirable as it reduces the overall efficiency of the open cycle gas turbine plant.

1.2.2 Combined cycle

In the combined cycle, two types of cycles are possible, a topping and a bottoming cycle. If power is generated first and the rejected energy used as the heat energy for another prime mover, that first system is known as a topping cycle. The secondary prime mover powered by the energy of the first system generating electricity is known as the bottoming cycle. This section will focus on gas turbine-based topping cycles and steam turbine-based bottoming cycles. However, any heat transfer fluids may be utilized as the medium for the bottoming cycle. The energy flow diagram in Figure 1.2 shows the distribution of the entering energy into its useful component and the energy losses which are associated with the condenser and the stack losses. This distribution will vary somewhat with different cycles as the stack losses are decreased with more efficient multilevel pressure Heat Recovery Steam Generators.

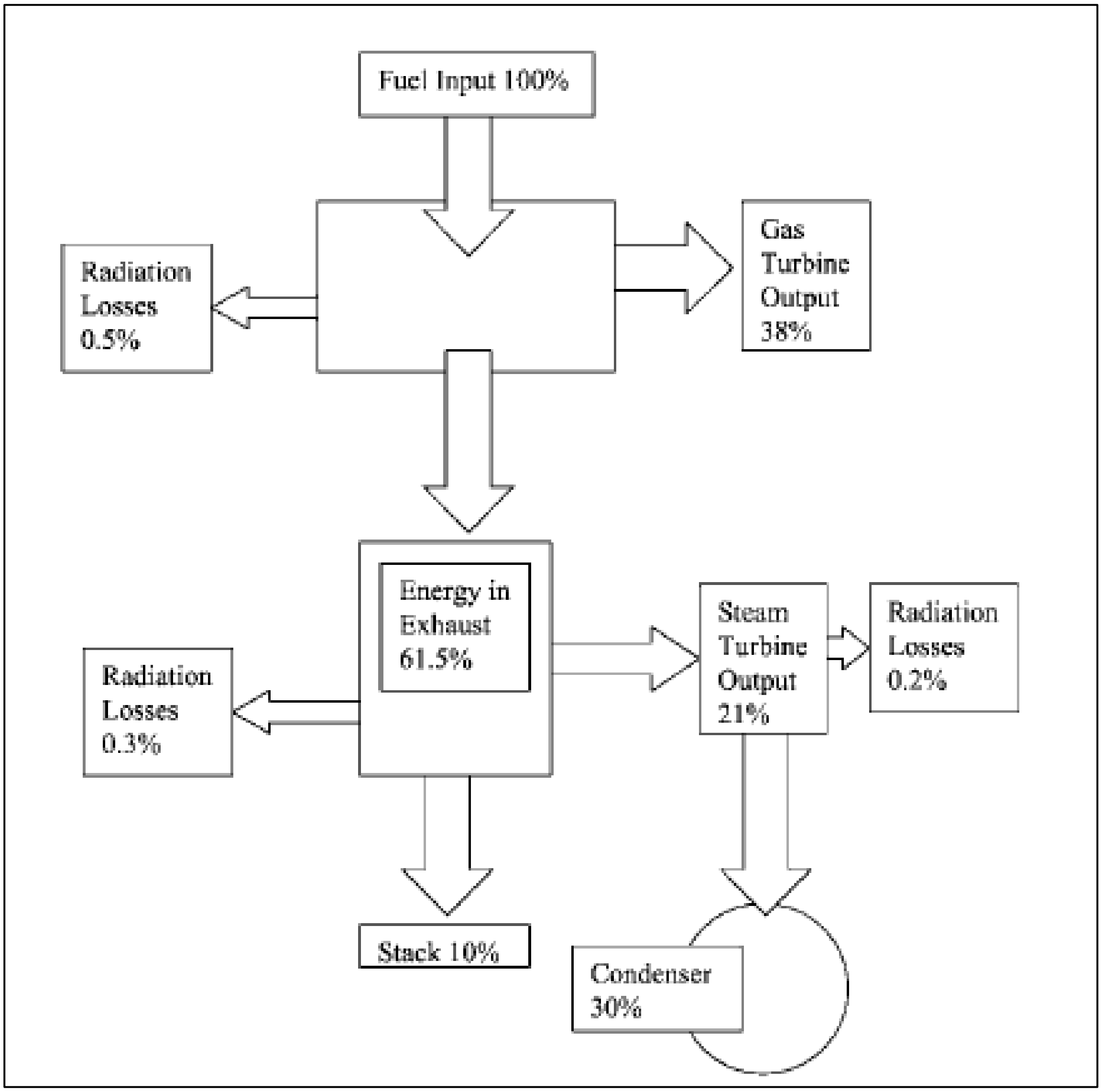


Figure 1.2 Combined cycle energy flow diagram

In most combined cycle applications, the gas turbine is the topping cycle and the steam turbine is the bottoming cycle. Thermal efficiencies of the combined cycles can reach as high as 60%. In the typical combination, the gas turbine produces about 60% of the power and the steam turbine about 40%. Individual unit thermal efficiencies of the gas turbine and the steam turbine are between 30% and 40%. The steam turbine utilizes the energy in the exhaust gas of the gas turbine as its input energy. The energy transferred to the heat recovery steam generator (HRSG) by the gas turbine is usually equivalent to about the rated output of the gas turbine at design conditions. At off-design conditions, the inlet guide vanes (IGV) are used to regulate the air so as to maintain a high temperature to the HRSG. About 40% of the energy is converted to power by the gas turbine, and about 20% of the energy is converted to power by the steam turbine.

The heat recovery steam generating (HRSG) is where the energy from the gas turbine is transferred to the water to produce steam. HRSG units are divided into sections such as a pre-heater or economizer, an evaporator, and then one or two stages of Superheaters. The steam entering the steam turbine is Superheated.

The steam turbines in most of the large power plants are at a minimum divided into two major sections the high-pressure (HP) section and the low pressure (LP) section. In some plants, the high-pressure section is further divided into a high-pressure section and an intermediate pressure (IP) section. The heat recovery steam generating (HRSG) is also divided into sections corresponding with the steam turbine. The LP steam turbine's performance is further dictated by the condenser backpressure, which is a function of the cooling and the fouling.

The efficiency of the steam section in many of these plants varies from 30% to 40%. To ensure that the steam turbine is operating in an efficient mode, the gas turbine exhaust temperature is maintained over a wide range of operating conditions. This enables the HRSG to maintain a high degree of effectiveness over this wide range of operation. The major components that make up a combined cycle are the gas turbine, the HRSG and the steam turbine. Figure 1.3 shows a typical combined cycle power plant with a single pressure HRSG.

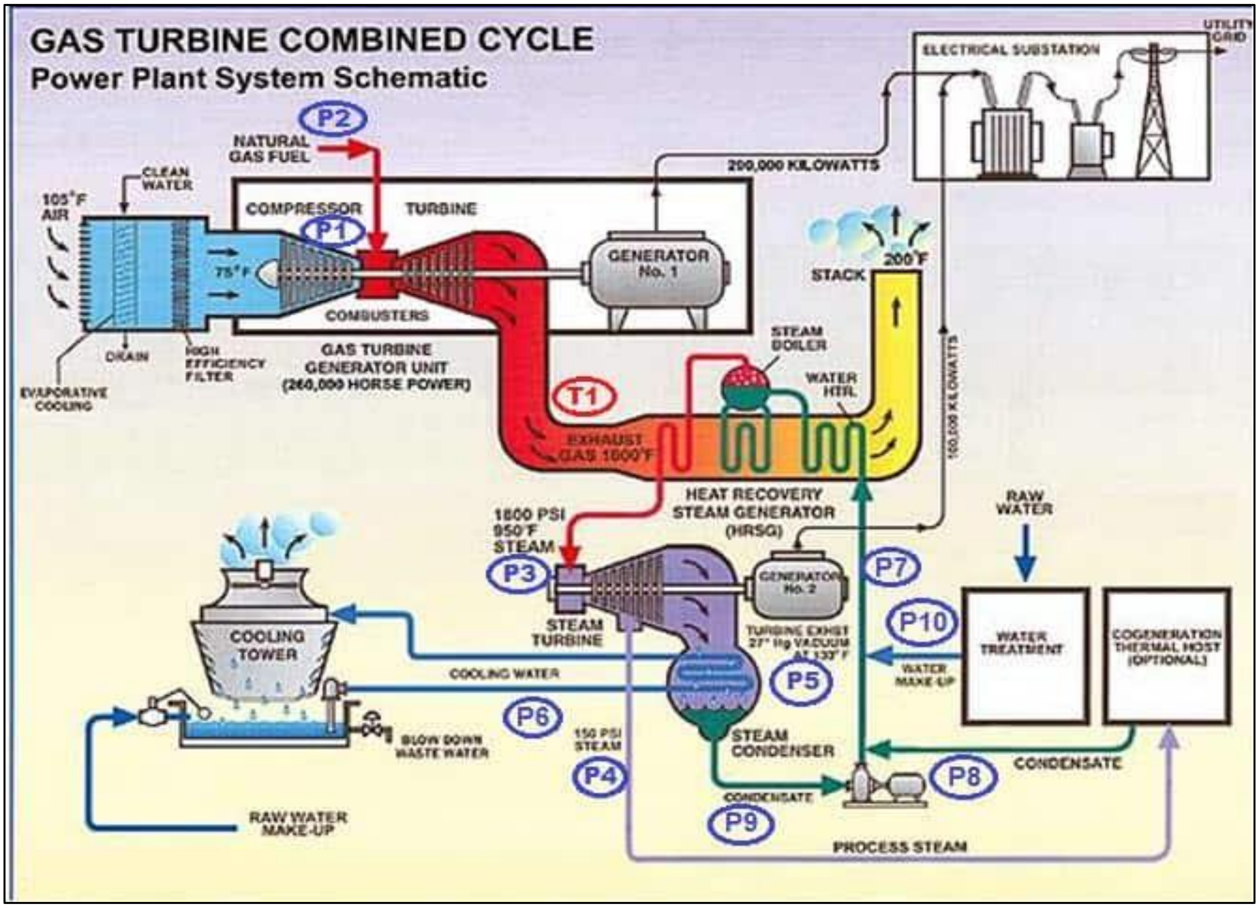


Figure 1.3 a typical combined cycle power plant

1.2.3 Purpose of the Performance Test

The purpose of the cogeneration plant performance test is to determine the power output and plant heat rate. In certain cases, the efficiency of individual components like steam turbine is addressed specifically where performance deterioration is suspected. In general, the plant performance will be compared with the baseline values arrived at for the plant operating condition rather than the design values. The other purpose of the performance test is to show the maintenance accomplishment after a major overhaul. In some cases, the purpose of evaluation could even be for a total plant revamp.

1.2.4 Performance Terms and Definitions

Overall Plant Performance

1. Overall plant heat rate, kCal/kWh

$$= \frac{\text{Mass flow rate of steam x (Enthalpy of steam, kCal/kg - Enthalpy of feed water, kCal/kg)}}{\text{Power output, kW}}$$

$$\text{2. Overall plant fuel rate kg/kWh} = \frac{\text{Fuel consumption* in kg/hr}}{\text{Power output,kW}}$$

*Total fuel consumption for turbine and steam

Steam Turbine Performance

$$\text{Turbine cylinder efficiency,\%} = \frac{\text{Actual enthalpy drop across the turbine, kCal/kg}}{\text{Isentropic (theoretical) enthalpy drop across the turbine, kCal/kg}} x\ 100$$

Gas Turbine Performance

$$\text{Air Compressor efficiency, \%} = \frac{\text{Theoretical temperature rise across the compressor, °C}}{\text{Actual temperature rise, °C}} \times 100$$

$$\text{Overall Gas turbine efficiency (Compressor + Gas turbine), \%} = \frac{\text{Power output, kW} \times 860}{\text{Fuel input for Gas turbine. kg/hr} \times \text{GCV of fuel, kCal/kg}} \times 100$$

Heat Recovery Steam Generator (HRSG) Performance

Heat Recovery Steam Generator efficiency, %

$$= \frac{\text{steam generated, kg/hr} \times (h_s\text{, kCal/kg} - h_w\text{,kCal/kg}) \times 100}{[\text{Mass flow of flue gas, kg/hr} \times Cp \times (t_{in} - t_{out})] + [\text{auxiliary fuel consumption, kg/hr} \times \text{GCV of fuel, kCal/kg}]}$$

where, h_s = Enthalpy of steam
h_w = Enthalpy of feed water
t_{in} = inlet temperature of flue gas
t_{out} = outlet temperature of flue gas

1.2.5 Field Testing Procedure

The test procedure for each cogeneration plant will be developed individually taking into consideration the plant configuration, instrumentation and plant operating conditions. A method is outlined in the following section for the measurement of heat rate and efficiency of a co-generation plant. This part provides a performance-testing procedure for a coal-fired steam-based co-generation plant, which is common in Indian industries.

1.2.3.1 Test Duration

The test duration is site-specific and in a continuous process industry, 8-hour test data should give reasonably reliable data. In case of an industry with fluctuating electrical/steam load profile, a set 24-hour data sampling for a representative period.

1.2.3.2 Measurements and Data Collection

The suggested instrumentation (online/ field instruments) for the performance measurement is as under:

Steam flow measurement	: Orifice flow meters
Fuel flow measurements	: Volumetric measurements / Mass flow meters

Air flow / Flue gas flow	: Venturi / Orifice flow meter / Ion gun / Pitot tubes
Flue gas Analysis	: Oxygen analyser
Unburnt Analysis	: Gravimetric Analysis
Temperature	: Thermocouple
Cooling water flow meters	: Orifice flow meter / weir /channel flow/non-contact flow
Pressure	: Pressure Gauges
Power	: Energy meter
Condensate	: Ultrasonic flow meter

It is essential to ensure that the data is collected during steady-state plant running conditions.Among others, the following are essential details to be collected for cogeneration plant performance evaluation.

I. Thermal Energy:

Sr no	Decription	Flow	Pressure	Temperature
1	Steam inlet to turbine	✓	✓	✓
2	Fuel input to boiler/ Gas turbine	✓		
3	Combustion air	✓	✓	✓
4	Extraction steam to process	✓	✓	✓
5	Back pressure steam to process	✓	✓	✓
6	Condensing steam	✓	✓	✓
7	Condensate from turbine	✓		✓
8	Turbine bypass steam	✓		
9	Flue gas to HRSG		✓	✓
10	Exit flue gas			✓+composition
11	Cooling water to condenser	✓	✓	✓

II. Electrical Energy:

1. Total power generation for the trial period from individual turbines.
2. Hourly average power generation
3. Quantity of power import from the utility (Grid)*
4. Quantity of power generation from DG sets.*
5. Auxiliaries power consumption

** Necessary only when overall cogeneration plant adequacy and system optimization up-gradation are the objectives of the study.*

1.2.3.3 Calculations for Steam Turbine Cogeneration System

The process flow diagram for the cogeneration plant is shown in figure 1.4. The following calculation procedures have been provided in this section.

- Turbine cylinder efficiency.
- Overall plant heat rate

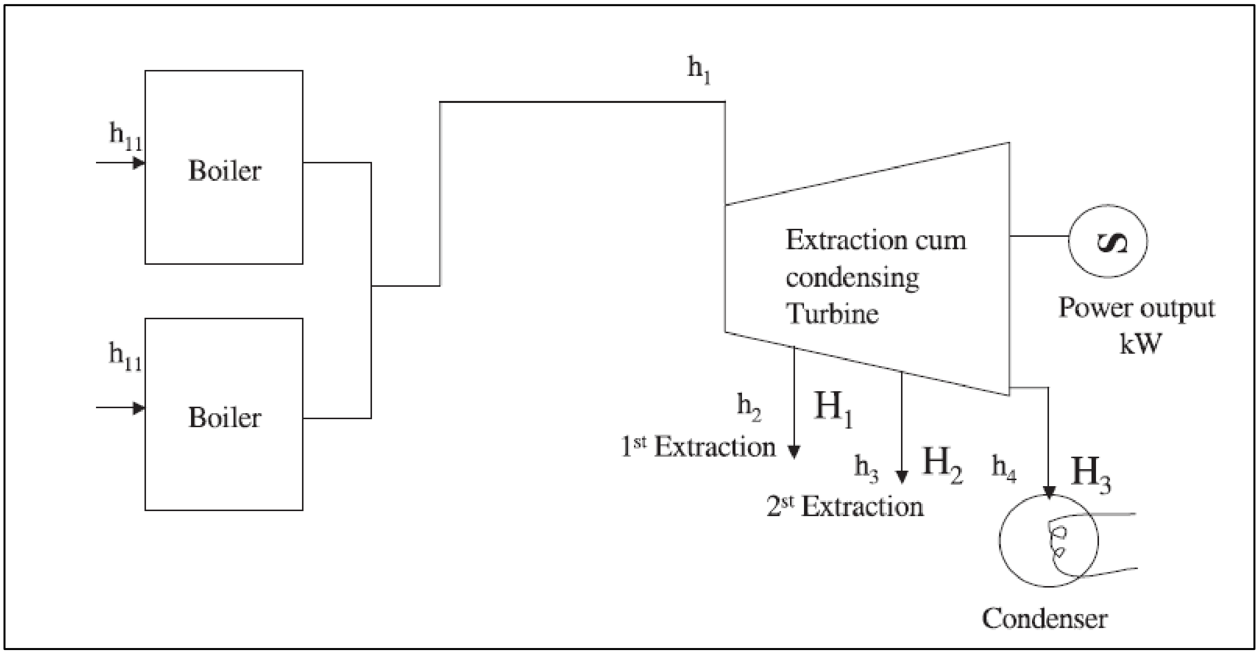


Figure 1.4 Process Flow Diagram for Cogeneration Plant

Step 1:

Calculate the actual heat extraction in turbine at each stage,

Steam Enthalpy at turbine inlet	: h1 kCal / kg
Steam Enthalpy at 1st extraction	: h2 kCal / kg
Steam Enthalpy at 2nd extraction	: h3 kCal / kg
Steam Enthalpy at Condenser	: h4* kCal / kg

* Due to wetness of steam in the condensing stage, the enthalpy of steam cannot be considered as equivalent to saturated steam. Typical dryness value is 0.88 – 0.92. This dryness value can be used as the first approximation to estimate heat drop in the last stage. However, it is suggested to calculate the last stage efficiency from the overall turbine efficiency and other stage efficiencies.

Heat extraction from inlet to stage –1 extraction (h5)	: h1 – h2 kCal / kg
Heat extraction from 1st –2nd extraction (h6)	: h2 – h3 kCal / kg
Heat extraction from 2nd Extraction – condenser (h7)	: h3 – h4 kCal / kg

Step 2:

From the Mollier diagram (H-S Diagram) estimate the theoretical heat extraction for the conditions mentioned in Step 1. Towards this:

a. Plot the turbine inlet condition point in the Mollier chart - corresponding to steam pressure and temperature.
b. Since expansion in the turbine is an adiabatic process, the entropy is constant. Hence draw a vertical line from inlet point (parallel to the y-axis) up to the condensing conditions.
c. Read the enthalpy at points where the extraction and condensing pressure lines meet the vertical line drawn.
d. Compute the theoretical heat drop for different stages of expansion.
   Theoretical Enthalpy after 1st extraction : H1
   Theoretical Enthalpy after 2nd extraction : H2
   Theoretical Enthalpy at condenser conditions: H3

   Theoretical heat extraction from inlet to stage 1 extraction, h8 : h1 – H1
   Theoretical heat extraction from 1st – 2nd extraction, h9 : H1 – H2
   Theoretical heat extraction from 2nd extraction – condensation, h10 : H2 – H3

Step 3 :

$$Efficiency\ of\ 1^{st}\ stage\left(\frac{h_5}{h_8}\right)=\frac{Heat\ extraction\ actual}{Heat\ extraction\ theoritical}=\frac{h_1-h_2}{h_1-H_1}$$

$$Efficiency\ of\ 2^{nd}\ stage\left(\frac{h_6}{h_9}\right)=\frac{Heat\ extraction\ actual}{Heat\ extraction\ theoritical}=\frac{h_2-h_3}{H_1-H_2}$$

Efficiency of condensing stage : $\frac{h_7}{h_{10}}$

Step 4 :

Calculate plant heat rate*

$$\text{Heat rate, kCal / kWh} = \frac{M \times (h_1 - h_{11})}{P}$$

M – Mass flow rate of steam in kg/hr
h1 – Enthalpy of inlet steam in kCal/kg
h11 – Enthalpy of feed water in kCal/kg
P – Average Power generated in kW
*Alternatively the following guiding parameter can be utilised

$$\text{Plant heat consumption} = \frac{\text{fuel consumed for power generation, kg/hr}}{\text{Power generated, kW}}$$

1.3 Boiler Efficiency Calculation

Performance of the boiler, like efficiency and evaporation ratio reduces with time, due to poor combustion, heat transfer fouling and poor operation and maintenance. Deterioration of fuel quality and water quality also leads to poor performance of boiler. Efficiency testing helps us to find out how far the boiler efficiency drifts away from the best efficiency. Any observed abnormal deviations could therefore be investigated to pinpoint the problem area for necessary corrective action. Hence it is necessary to find out the current level of efficiency for performance evaluation, which is a pre requisite for energy conservation action in industry.

1.3.1 Purpose of the Performance Test

- To find out the efficiency of the boiler
- To find out the Evaporation ratio

The purpose of the performance test is to determine the actual performance and efficiency of the boiler and compare it with design values or norms. It is an indicator for tracking day-to-day and season-to-season variations in boiler efficiency and energy efficiency improvements

1.3.2 Performance Terms and Definitions

1. Boiler Efficiency, η =

$$\boxed{\frac{\text{Heat output}}{\text{Heat Input}} \text{ x } 100}$$

$$= \boxed{\frac{\text{Heat in steam output (kCals)}}{\text{Heat in Fuel Input} \quad \text{(kCals)}} \text{ x } 100}$$

2. Evaporation Ratio =

$$\boxed{\frac{\text{Quantity of Steam Generation}}{\text{Quantity of fuel Consumption}}}$$

Basically Boiler efficiency can be tested by the following methods:

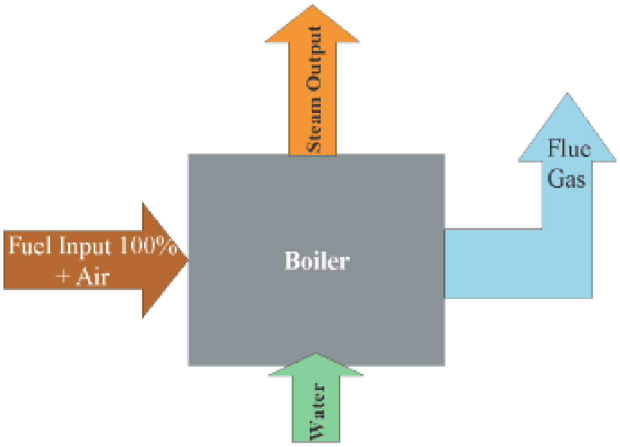
1) **The Direct Method:** Where the energy gain of the working fluid (water and steam) is compared with the energy content of the boiler fuel.

2) **The Indirect Method:** Where the efficiency is the difference between the losses and the energy input.

1.3.3 The Direct Method Testing

This is also known as 'input-output method' since 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:

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



$$\text{Efficiency} = \frac{\text{Heat addition to Steam}}{\text{Gross Heat in Fuel}} \times 100$$

$$\textit{Boiler Efficiency} = \frac{\text{Steam flow rate x (steam enthalpy} - \text{feed water enthalpy)}}{\text{Fuel firing rate x Gross calorific value}} \times 100$$

Measurements Required for Direct Method Testing

Heat input

Both heat input and heat output must be measured. The measurement of heat input requires knowledge of the calorific value of the fuel and its flow rate in terms of mass or volume, according to the nature of the fuel.

For gaseous fuel:

A gas meter of the approved type can be used and the measured volume should be corrected for temperature and pressure. A sample of gas can be collected for calorific value determination, but it is usually acceptable to use the calorific value declared by the gas suppliers.

For liquid fuel:

Heavy fuel oil is very viscous, and this property varies sharply with temperature. The meter, which is usually installed on the combustion appliance, should be regarded as a rough indicator only and, for test purposes, a meter calibrated for the particular oil is to be used and over a realistic range of temperature should be installed. Even better is the use of an accurately calibrated day tank.

For solid fuel:

The accurate measurement of the flow of coal or other solid fuel is very difficult. The measurement must be based on mass, which means that bulky apparatus must be set up on the boiler-house floor. Samples must be taken and bagged throughout the test, the bags sealed and sent to a laboratory for analysis and calorific value determination. In some more recent boiler houses, the problem has been alleviated by mounting the hoppers over the boilers on calibrated load cells, but these are yet uncommon.

Heat output

There are several methods, which can be used for measuring heat output. With steam boilers, an installed steam meter can be used to measure flow rate, but this must be corrected for temperature and pressure. In earlier years, this approach was not favoured due to the change in accuracy of the orifice or venturi meters with flow rate. It is now more viable with modern flow meters of the variable-orifice or vortex-shedding types.

The alternative with small boilers is to measure feed water, and this can be done by previously calibrating the feed tank and noting down the levels of water during the beginning and end of the trial. Care should be taken not to pump water during this period. Heat addition for conversion of feed water at inlet temperature to steam, is considered for heat output.

In case of boilers with intermittent blowdown, blowdown should be avoided during the trial period. In case of boilers with continuous blowdown, the heat loss due to blowdown should be calculated and added to the heat in steam.

Merits and Demerits of Direct Method

Merits

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

Demerits

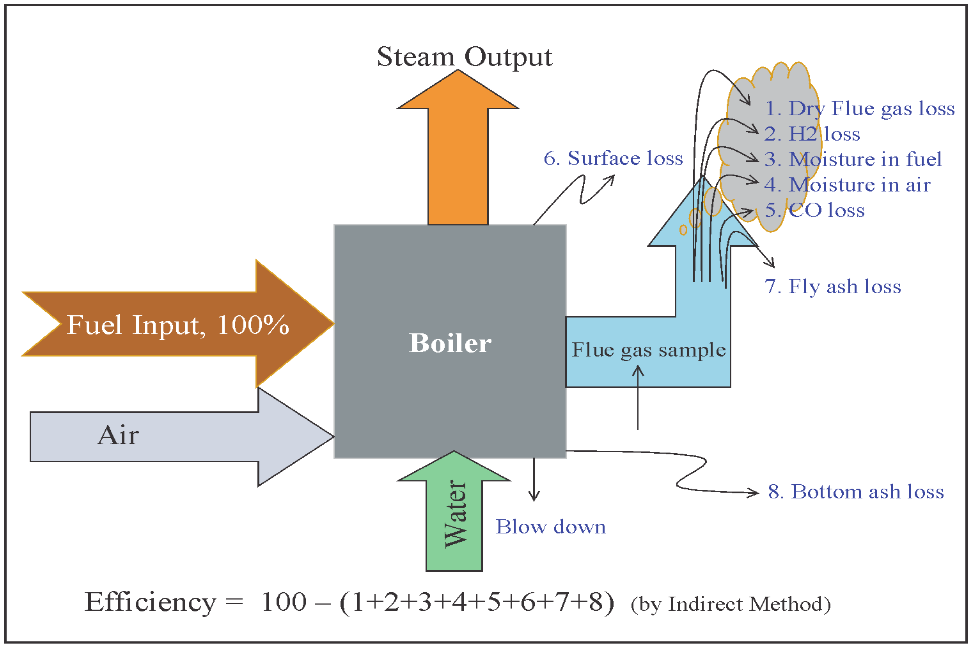
- Does not give clues to the operator as to why the efficiency of system is lower
- Does not calculate various losses accountable for various efficiency levels
- Evaporation ratio and efficiency may mislead if the steam is highly wet due to water carryover

1.3.4 The Indirect Method Testing

The efficiency can be measured easily by measuring all the losses occurring in the boilers using the principles to be described. The disadvantages of the direct method can be overcome by this method, which calculates the various heat losses associated with the boiler. The efficiency can be arrived at, by subtracting the heat loss fractions from 100. An important advantage of this method is that the errors in measurement do not make a significant change in efficiency.

Thus if boiler efficiency is 90%, an error of 1% in direct method will result in significant change in efficiency. i.e. 90 – 0.9 = 89.1 to 90.9. In indirect method, 1% error in measurement of losses will result in Efficiency = 100 – (10 – 0.1) = 90 – 0.1 = 89.9 to 90.1.

The various heat losses occurring in the boiler are:



The following losses are applicable to liquid, gas and solid fired boiler

L1– Loss due to dry flue gas (sensible heat)
L2– Loss due to hydrogen in fuel (H_2)
L3– Loss due to moisture in fuel (H_2O)
L4– Loss due to moisture in air (H_2O)
L5– Loss due to carbon monoxide (CO)
L6– Loss due to surface radiation, convection and other unaccounted*.

*Losses which are insignificant and are difficult to measure.

The following losses are applicable to solid fuel fired boiler in addition to above
L7– Unburnt losses in fly ash (Carbon)
L8– Unburnt losses in bottom ash (Carbon)
Boiler Efficiency by indirect method = 100 – (L1 + L2 + L3 + L4 + L5 + L6 + L7 + L8)

Measurements Required for Performance Assessment Testing

The following parameters need to be measured, as applicable for the computation of boiler efficiency and performance.

a) Flue gas analysis
   1) Percentage of CO2 or O_2 in flue gas
   2) Percentage of CO in flue gas
   3) Temperature of flue gas

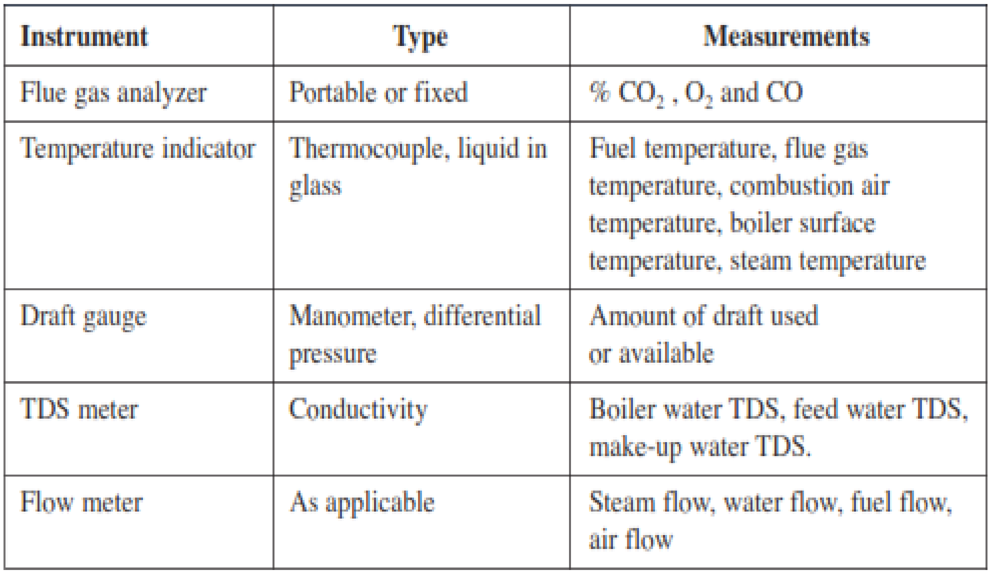
- b) Flow meter measurements for
    1) Fuel
    2) Steam
    3) Feed water
    4) Condensate water
    5) Combustion air

- c) Temperature measurements for
    1) Flue gas
    2) Steam
    3) Makeup water
    4) Condensate return
    5) Combustion air
    6) Fuel
    7) Boiler feed water

- d) Pressure measurements for
    1) Steam
    2) Fuel
    3) Combustion air, both primary and secondary
    4) Draft
- e) Water condition
    1) Total dissolved solids (TDS)
    2) pH
    3) Blowdown rate and quantity

The various parameters that were discussed above can be measured with the instruments that are given in Table 1.1.

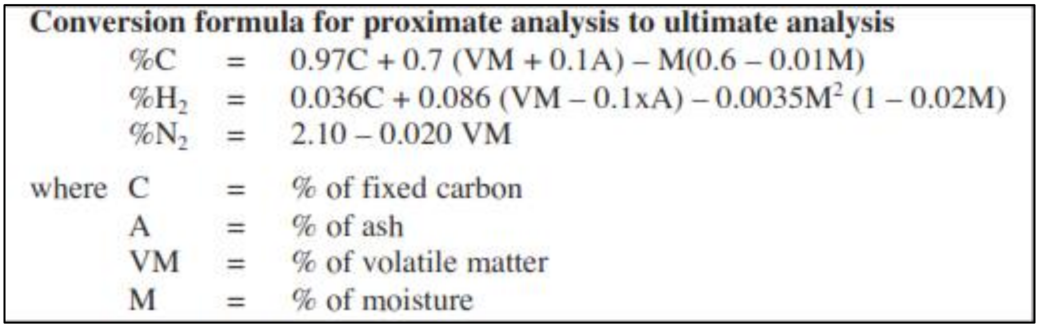
Table 1.1 Boiler parameters measuring instruments



Instrument	Type	Measurements
Flue gas analyzer	Portable or fixed	% CO_2 , O_2 and CO
Temperature indicator	Thermocouple, liquid in glass	Fuel temperature, flue gas temperature, combustion air temperature, boiler surface temperature, steam temperature
Draft gauge	Manometer, differential pressure	Amount of draft used or available
TDS meter	Conductivity	Boiler water TDS, feed water TDS, make-up water TDS.
Flow meter	As applicable	Steam flow, water flow, fuel flow, air flow

Boiler Efficiency by Indirect Method: Calculation Procedure and Formula

In order to calculate the boiler efficiency by the indirect method, all the losses that occur in the boiler must be established. These losses are conveniently related to the amount of fuel burnt. In this way, it is easy to compare the performance of various boilers with different ratings.



Conversion formula for proximate analysis to ultimate analysis

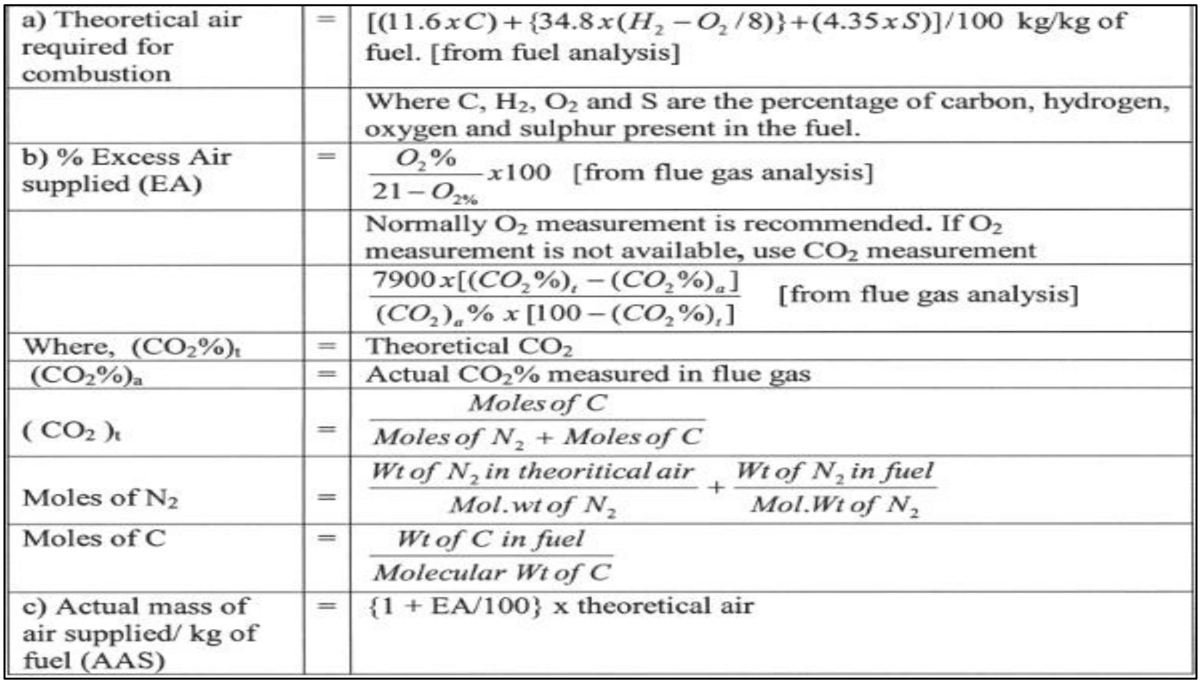
$\%C = 0.97C + 0.7\ (VM + 0.1A) - M(0.6 - 0.01M)$

$\%H_2 = 0.036C + 0.086\ (VM - 0.1xA) - 0.0035M^2\ (1 - 0.02M)$

$\%N_2 = 2.10 - 0.020\ VM$

where C = % of fixed carbon
A = % of ash
VM = % of volatile matter
M = % of moisture

However, it is suggested to get an ultimate analysis of the fuel-fired periodically from a reputed laboratory. Theoretical (stoichiometric) air-fuel ratio and excess air supplied are to be determined first for computing the boiler losses. The formula is given below for the same.



a) Theoretical air required for combustion	=	$[(11.6xC)+\{34.8x(H_2-O_2/8)\}+(4.35xS)]/100$ kg/kg of fuel. [from fuel analysis]
		Where C, H_2, O_2 and S are the percentage of carbon, hydrogen, oxygen and sulphur present in the fuel.
b) % Excess Air supplied (EA)	=	$\frac{O_2\%}{21-O_{2\%}}x100$ [from flue gas analysis]
		Normally O_2 measurement is recommended. If O_2 measurement is not available, use CO_2 measurement
		$\frac{7900x[(CO_2\%)_t-(CO_2\%)_a]}{(CO_2)_a\%\ x\ [100-(CO_2\%)_t]}$ [from flue gas analysis]
Where, $(CO_2\%)_t$	=	Theoretical CO_2
$(CO_2\%)_a$	=	Actual $CO_2\%$ measured in flue gas
$(CO_2)_t$	=	$\frac{Moles\ of\ C}{Moles\ of\ N_2 + Moles\ of\ C}$
Moles of N_2	=	$\frac{Wt\ of\ N_2\ in\ theoritical\ air}{Mol.wt\ of\ N_2} + \frac{Wt\ of\ N_2\ in\ fuel}{Mol.Wt\ of\ N_2}$
Moles of C	=	$\frac{Wt\ of\ C\ in\ fuel}{Molecular\ Wt\ of\ C}$
c) Actual mass of air supplied/ kg of fuel (AAS)	=	{1 + EA/100} x theoretical air

The various losses associated with the operation of a boiler are discussed below with the required formula.

1. Heat loss due to dry flue gas

This is the greatest boiler loss and can be calculated with the following formula:

$$L1 = \frac{m \times C_p \times (Tf - Ta)}{GCV \text{ of fuel}} \times 100$$

Where,

L1 = % Heat loss due to dry flue gas
m = Mass of dry flue gas in kg/kg of fuel
= Combustion products from fuel: CO2 + SO2 + Nitrogen in fuel + Nitrogen in the actual mass of air supplied + O2 in flue gas. (H2O/Water vapour in the flue gas should not be considered)
Cp = Specific heat of flue gas in kCal/kg°C
Tf = Flue gas temperature in °C
Ta = Ambient temperature in °C

Note–1:
For quick and simple calculation of boiler efficiency use the following.

A: Simple method can be used for determining the dry flue gas loss as given below.

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

Total mass of flue gas (m)/kg of fuel = mass of actual air supplied/kg of fuel + 1 kg of fuel

Note-2: Water vapour is produced from Hydrogen in fuel, moisture present in fuel and air during the combustion. The losses due to these components have not been included in the dry flue gas loss since they are separately calculated as a wet flue gas loss.

2. Heat loss due to evaporation of water formed due to H_2 in fuel (%)

The combustion of hydrogen causes a heat loss because the product of combustion is water This water is converted to steam and this carries away heat in the form of its latent heat.

$$L_2 = \frac{9 \times H_2 \times \{584 + C_p (T_f - T_a)\}}{GCV \text{ of fuel}} \times 100$$

Where

H2 = kg of hydrogen present in fuel on 1 kg basis
Cp = Specific heat of superheated steam in kCal/kg°C
Tf = Flue gas temperature in °C
Ta = Ambient temperature in °C
584 = Latent heat corresponding to partial pressure of water vapour

3. Heat loss due to moisture present in fuel

Moisture entering the boiler with the fuel leaves as a superheated vapour. This moisture loss is made up of the sensible heat to bring the moisture to boiling point, the latent heat of evaporation of the moisture, and the superheat required to bring this steam to the temperature of the exhaust gas. This loss can be calculated with the following formula.

$$L_3 = \frac{M \text{ x } \{584 + C_p (T_f - T_a)\}}{\text{GCV of fuel}} \text{ X } 100$$

Where

M = kg moisture in fuel on 1 kg basis
Cp = Specific heat of superheated steam in kCal/kg°C
Tf = Flue gas temperature in °C
Ta = Ambient temperature in °C
584 = Latent heat corresponding to partial pressure of water vapour

4. Heat loss due to moisture present in air

Vapour in the form of humidity in the incoming air, is superheated as it passes through the boiler. Since this heat passes up the stack, it must be included as a boiler loss. To relate this loss to the mass of coal burned, the moisture content of the combustion air and the amount of air supplied per unit mass of coal burned must be known.

$$L_4 = \frac{\text{AAS x humidity factor x } C_p \text{ x } (T_f - T_a) \text{ x } 100}{\text{GCV of fuel}}$$

Where

AAS = Actual mass of air supplied per kg of fuel
Humidity factor = kg of water/kg of dry air
C_p = Specific heat of superheated steam in kCal/kg°C
T_f = Flue gas temperature in °C
T_a = Ambient temperature in °C (dry bulb)

5. Heat loss due to incomplete combustion:

Products formed by incomplete combustion could be mixed with oxygen and burned again with, a further release of energy. Such products include CO, H_2 and various hydrocarbons and are generally found in the flue gas of the boilers. Carbon monoxide is the only gas whose concentration can be determined conveniently in a boiler plant test.

$$L_5 = \frac{\%CO \times C}{\%CO + \%CO_2} \times \frac{5744}{\text{GCV of fuel}} \times 100$$

L_5 = % Heat loss due to partial conversion of C to CO
CO = Volume of CO in flue gas leaving economizer (%)
CO_2 = Actual Volume of CO_2 in flue gas (%)
C = Carbon content kg / kg of fuel

or

When CO is obtained in ppm during the flue gas analysis
CO formation (M_{co}) = CO (in ppm) x 10^{-6} x M_f x 28
M_f = Fuel consumption in kg/hr
L_5 = M_{co} x 5744*

* Heat loss due to partial combustion of carbon.

6. Heat loss due to radiation and convection:

The other heat losses from a boiler consist of the loss of heat by radiation and convection from the boiler casting into the surrounding boiler house.

Normally surface loss and other unaccounted losses are assumed based on the type and size of the boiler as given below

For industrial fire tube / packaged boiler = 1.5 to 2.5%
For industrial watertube boiler = 2 to 3%
For power station boiler = 0.4 to 1%

However, it can be calculated if the surface area of the boiler and its surface temperature is known as given below:

$$L_6 = 0.548 \times [(T_s / 55.55)^4 - (T_a / 55.55)^4] + 1.957 \times (T_s - T_a)^{1.25} \times \text{sq.rt of } [(196.85\, V_m + 68.9) / 68.9]$$

where

L6 = Radiation loss in W/m2
Vm = Wind velocity in m/s
Ts = Surface temperature (K)
Ta = Ambient temperature (K)

Heat loss due to unburned carbon in fly ash and bottom ash:

Small amounts of carbon will be left in the ash and this constitutes a loss of potential heat in the fuel. To assess these heat losses, samples of ash must be analyzed for carbon content. The quantity of ash produced per unit of fuel must also be known.

7. Heat loss due to unburnt in fly ash (%)

$$L_7 = \frac{\text{Total ash collected / kg of fuel burnt x G.C.V of fly ash x 100}}{\text{GCV of fuel}}$$

8. Heat loss due to unburnt in bottom ash (%)

$$L_8 = \frac{\text{Total ash collected per kg of fuel burnt x G.C.V of bottom ash x 100}}{\text{GCV of fuel}}$$

Heat Balance:

Having established the magnitude of all the losses mentioned above, a simple heat balance would give the efficiency of the boiler. The efficiency is the difference between the energy input to the boiler and the heat losses calculated.

Boiler Heat Balance:

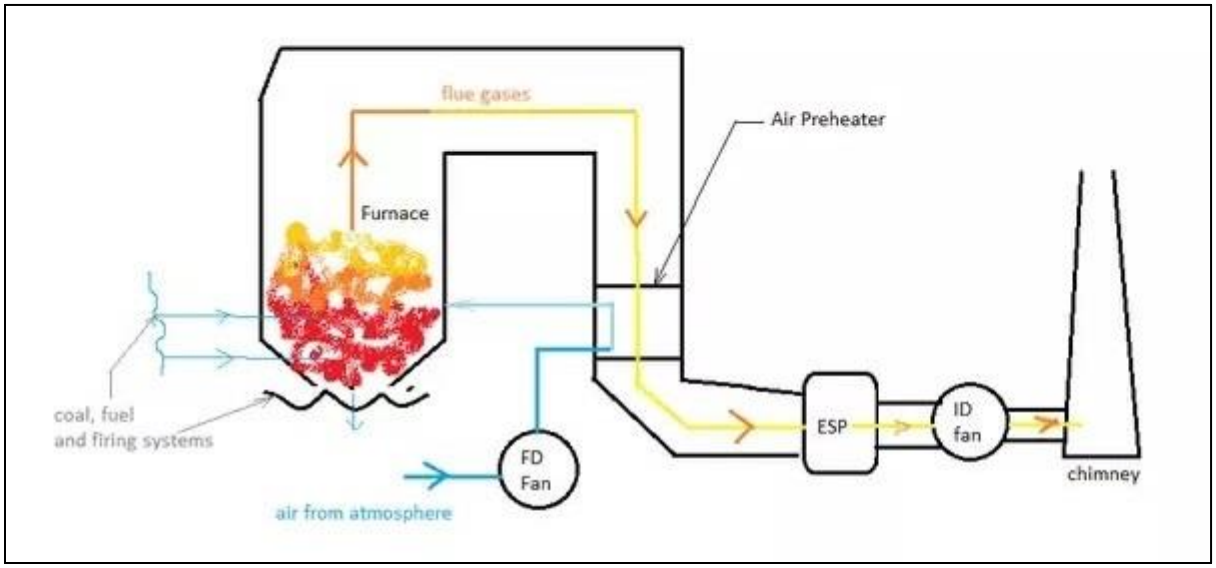
Input/Output Parameter		**kCal / kg of fuel**	**%**
Heat Input in fuel	=		100
Various Heat losses in boiler			
1. Dry flue gas loss	=		
2. Loss due to hydrogen in fuel			
3. Loss due to moisture in fuel	=		
4. Loss due to moisture in air	=		
5. Partial combustion of C to CO	=		
6. Surface heat losses	=		
7. Loss due to Unburnt in fly ash	=		
8. Loss due to Unburnt in bottom ash	=		
Total Losses	=		
Boiler efficiency = 100 – (1+2+3+4+5+6+7+8)			

1.4 Draft system

1.4.1 Overview of draft system

In power plant combustion processes, the largest demands for auxiliary drive power come from the ID and FD fans. Typically, FD and ID fan motors consume enormous amounts of energy in a plant. When a boiler is operating at non-peak loads and the traditional fan-motor-damper system is in use, a good deal of energy is wasted in the fan/motor combination. Example, if a 1.5 MW motor is wasting 20 percent of its energy due to inefficient flow control, that waste amounts to 300kWh during each hour of operation.

In power plants, fans used to supply combustion air are termed forced draft (FD) fans, and fans used to exhaust combustion flue gases are termed induced draft (ID) fans. Primary air (PA) fans supply air to carry an air + fuel mixture through ducts to the burner nozzle (or fuel bed). Together, all the fans electric drive power may add up to 2-3% of the plant's rated output. Overview of boiler draft system is given in figure below.



Generally, axial fans are typically used in FD and ID fans on balanced draft steam generators. If a centrifugal fan is used, then it is likely to have backward curved blades for improved efficiency. On larger plants, all these fans are typically configured in pairs working in parallel, mainly for reasons of redundancy.

In power plants terminology, the supply fans are the Primary Air (PA) and Forced Draft (FD) fans which supply air to the furnace chamber. The return fans are the Induced Draft (ID) fan. Designs with both FD and ID fans are termed 'balanced draft' plants, and the balance point of zero gauge pressure is the furnace.

FD fans must develop pressure to overcome system resistance in ductwork, air heater, burner or fuel bed and the furnace itself. FD fans must supply enough flow to serve needs of fuel combustion plus flow lost due to air leaks in the heater and other areas. FD fans draw fresh air and therefore are more vulnerable to density changes due to outside air temperature change than ID fans. Colder, denser air increases the mass flow and power requirements.

1.4.2 Fan Flow Control Methods

When centrifugal fans are required to operate at variable loads, the pressure and flow may be controlled by one of the following methods:
–– Inlet dampers
–– Inlet guide vanes
–– Outlet dampers
–– Two-speed motor control
–– Variable speed control by VFD or hydraulic coupling methods

When inlet dampers and guide vanes are partially closed they create a pre-swirl in the direction of rotation of the fan. This motion reduces the relative velocity of the air concerning the fan blades and therefore reduces the fan capacity and pressure.

Inlet guide vane control is more efficient than inlet dampers due to reduced friction in creating the pre-swirl movement.

Outlet dampers are least efficient of all methods; they throttle the airflow to remove power supplied by the fan. As outlet dampers close, the system curve becomes steeper, intersecting the fan curve at the required lower flow rate, and at a point below the fan's BEP.

In applications requiring variable flow and pressure, Variable Frequency Drive (VFD's) are the most efficient method of control. Varying the speed of the fan adjusts the flow rate to the system requirements without the need of additional mechanical devices, and at high efficiency. The benefits of VFDs are diminished in applications with higher system (back) pressures, where the system curve is flatter.

In power plants, ID fans are ideal candidates for VFD control. ID Fan flow curves compared to centrifugal fans are also well suited for VSD control. Good control can be achieved by VFD motor speed control based on feedback of oxygen percentage in flue gas, loading of boiler and draft pressure.

1.5 Water pumping system

1.5.1 Overview of water pumping system

Boiler water pumping system consists of associated piping, pumps and other equipment that is intended for evaporation into steam, cooling of auxiliary equipment's and turbine exhaust steam condensation.

Circulating pump supplies cooling water at a large flow rate and low head to the condenser for heat exchange. Circulating pumps are usually mixed flow pumps, with axial designs being used for very low head applications. Typical flow rates for circulating water pumps are between 0.35gpm and 0.75gpm per generated kW.

Condensate pumps are usually 2-stage pumps that operate with a high vacuum on the inlet. The discharge pressure must be sufficient to overcome the friction in the piping and low-pressure feed-water heaters, and any static lift required to pump the condensate to the level of the low-pressure feedwater heaters. Typical power required by condensate pumps is on the order of 3hp per MW of generating capacity.

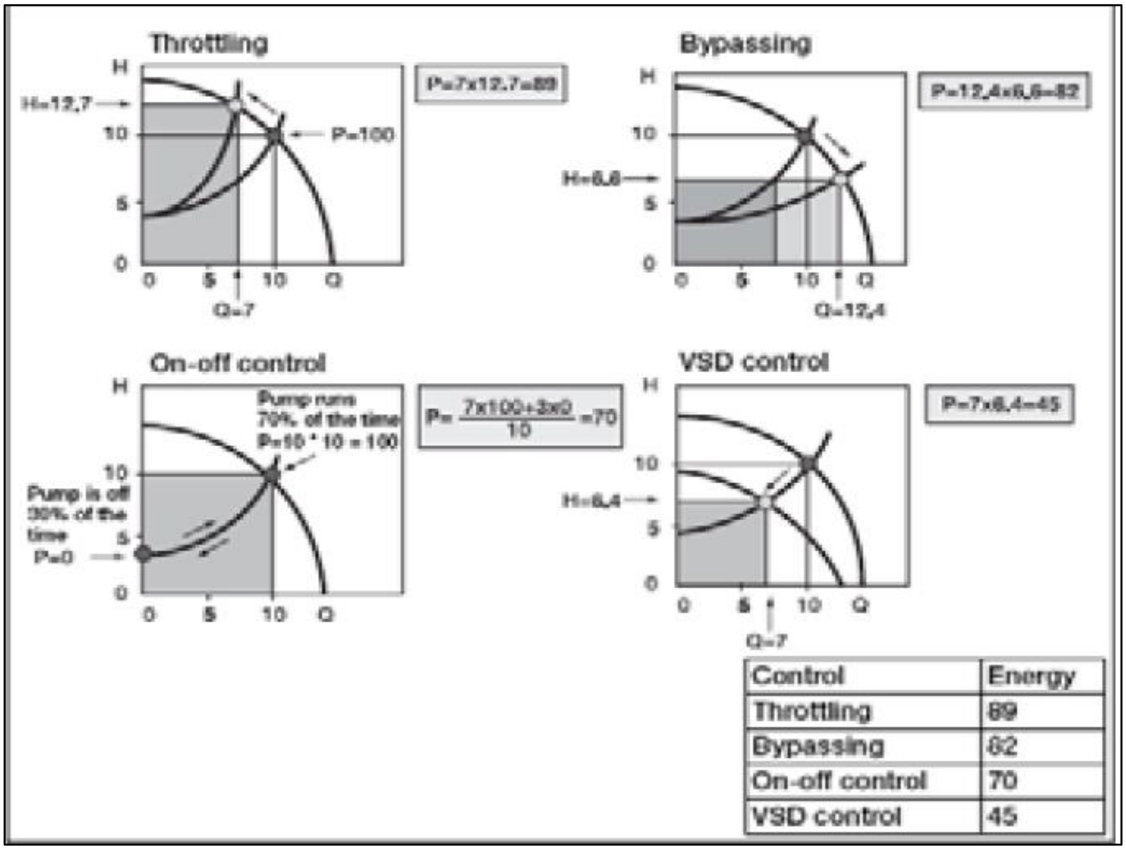
Boiler feedwater (BFW) pumps are usually multi-stage, volute type centrifugal pumps. The head of the boiler feed pump depends upon the boiler load and thus steam pressure, which varies with plant loading. Feed-water pumps are characterized by high-reliability requirements and fairly high dynamics during plant load changes. They normally make the biggest contribution to the plant's in-house energy consumption. Estimated boiler-feed water pump consumption is around 2.5% of gross power.

1.5.2 Pump Flow Control Methods

There are four common methods to control the output of a pumping system such as throttling, bypassing, On-Off, and variable speed control. The relative power consumption of the different control methods can be estimated from the operating point on a pressure-flow curve. This comparison is based on the formula for pump power (P): flow x head (P=Q x H).

Throttling

Flow control can be achieved by modulating a valve immediately downstream from the pump. Throttling effectively changes the process system curve, the valve introduces friction into the system; this makes the system curve steeper so that it intersects the pump curve at the lower, desired flow rate. Same is shown in the top-left chart in the figure below. This method has low capital costs, but throttled systems waste energy in two main ways: pressure drop across the valve, and because at reduced capacity the pump performs below its optimum efficiency point.



Control	Energy
Throttling	89
Bypassing	82
On-off control	70
VSD control	45

Bypassing

Bypassing also known as "recirculation" is applied mainly to circulation duty pumps. The flow output to the system is reduced by bypassing part of the pump discharge flow to the pump suction. Flow through the bypass system is controlled by valves. This means that the total flow increases, but the head decreases.

A minimum flow recirculation system is sometimes necessary if the pump operates for extended periods at low flow rates when the pressure is too low to induce adequate flow into the system.. Recirculating flow wastes energy therefore it should be kept to a minimum. Automatic modulating control of the recirculating flow system will ensure that that the recirculation flow control valve only opens when measured pump flow drops below a certain minimum threshold. Recirculating systems are sometimes required on systems equipped with variable speed flow control to guard against low flow conditions.

On-Off Control

On-off control is often used where step-less control is not necessary, such as keeping the pressure in a tank between preset limits; in these applications, the pump is either running or stopped. The average flow is the relationship between the 'on' time and the 'total' time, on plus off.

Variable Speed Control

The Best Efficiency Points (BEPs), when plotted for each pump curve, follow a quadratic shape that is in accordance with the affinity laws; pressure ratios are proportional to the square of flow ratios. In low static head, mostly friction systems, the system curve has approximately the same quadratic shape as the pump's best efficiency curve. By varying the speed, therefore, the operating point can be made to follow the unchanged system curve along a line which is close to the BEP line. If the pump impeller speed is reduced, the pump curve moves downwards. If the speed is increased, then it moves upwards. This relationship ensures that the pumping capacity is exactly matched to the process requirements.

1.6 Turbine heat rate calculation:

1.6.1 Introduction

A steam turbine may be defined as a form of heat engine in which the energy of the steam is transformed into kinetic energy by means of expansion through nozzles, and the kinetic energy of the resulting jet is in turn converted into force doing work on rings of blading mounted on a rotating part. The basic idea of steam turbines was conceived as early as 120 BC, yet it was in 1883 that the first practical steam turbine was developed by De Laval.

A typical steam turbine power plant is divided up into its heat sources, the boiler or steam generator and the turbine cycle, which includes the turbine, generator, condenser pumps, and feed water heaters. The steam turbine operates on the Rankine Cycle. They can be further divided into a non-condensing or condensing cycle.

The non-condensing cycle (back-pressure operation) involves taking medium- to-high-pressure steam into the turbine and exhausting it to a process header where the pressure is higher than atmospheric. Cycle efficiency is high because the turbine and process absorb most of the heat before the condensate returns to the boiler.

The condensing cycle is used mostly on large steam turbines where the pressure (over 1000psia) and temperature (over a 1000°F) of the steam are high and the power output well over 20 MW. This cycle takes the turbine's exhaust steam to a condenser at below atmospheric pressure. Because the condenser's cooling water absorbs most of the heat, cycle efficiency is low.

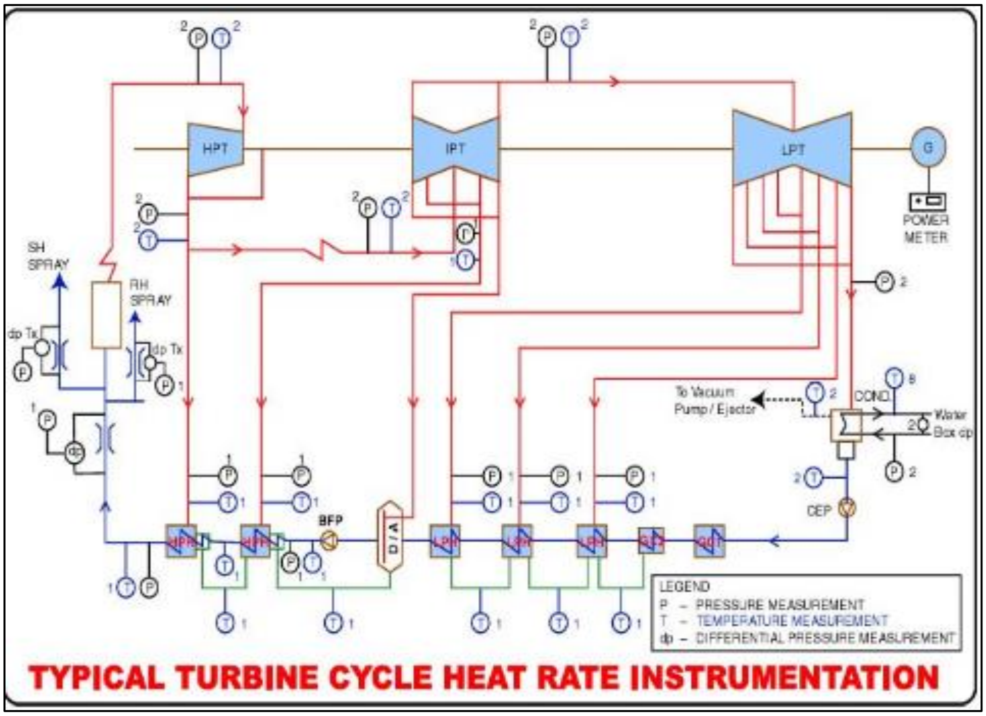
1.6.2 Test Procedure

The objective of the Gross Turbine Cycle Heat rate (GTCHR) test is the measure of efficiency of a Steam turbine cycle. It is defined as heat energy used by the turbine cycle to generate one unit of Electrical energy.

This method determines the overall efficiency of Turbine cycle along with the auxiliaries. The unit is to be operated at steady conditions at constant load with feedwater heaters in service at normal cascading. To ensure accuracy, each independent variable must be controlled, such that all subsequent tests may be related to all previous tests.

Table 1.2 Station Instrumentation Required

Measurement	Temperature	Pressure	Flow	Electric power
Feed water (At Eco inlet)	Yes	Yes	Yes	
Feed water (At HPH Inlet & Outlet)	Yes	Yes		
Reheater Attemperation	Yes	Yes	Yes	
SH Attemperation (as applicable)	Yes	Yes	Yes	
Main Steam (L&R) Before ESV	Yes	Yes		
HPT Exhaust (L&R)	Yes	Yes		
Hot Reheat Steam (L&R) Before IV	Yes	Yes		
HP Turbine Extraction to HPH at Heater end	Yes	Yes		
HPH Drip	Yes			
Gross Generator Output Yes				



TYPICAL TURBINE CYCLE HEAT RATE INSTRUMENTATION

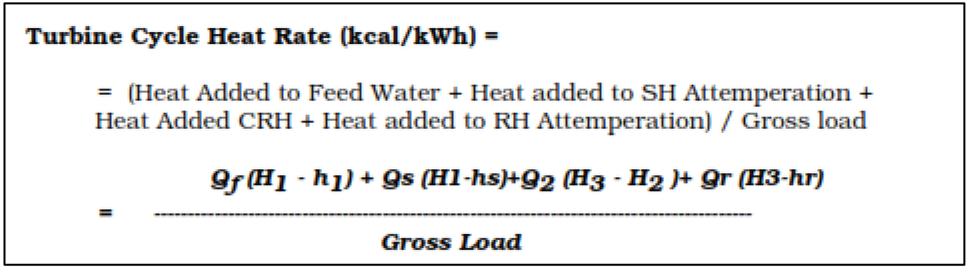
1.6.2.1 Operating Conditions for Each Test Run

1. Unit Load Control on manual mode and Steady
2. Main Steam and Reheat Steam Temperatures at Current Expected Value
3. All Feedwater Heaters in Service, Normal Drain cascading,
4. No Auxiliary Steam supply to Other Units.
5. No Soot Blowing.
6. No DM make up
7. The Test Engineer is responsible for ensuring that the unit has reached steady state before beginning a test data collection

1.6.2.2 Data Collection

1. Form a data group in the DAS for Data collection during the test
2. Each test must be conducted for about 30 min for the purposes of data collection.
3. The frequency of data collection in DAS should be 1 min or minimum possible to achieve, depending upon the data collection rate of DAS.

1.6.2.3 Turbine Cycle Heat Rate.



Turbine Cycle Heat Rate (kcal/kWh) =

= (Heat Added to Feed Water + Heat added to SH Attemperation + Heat Added CRH + Heat added to RH Attemperation) / Gross load

$$= \frac{Q_f(H_1 - h_1) + Qs\,(H1\text{-}hs) + Q_2\,(H_3 - H_2) + Qr\,(H3\text{-}hr)}{\text{Gross Load}}$$

Where,

Main Steam Flow	t/hr	(Q1)
Feed Water Flow	t/hr	(Qf)
CRH Flow	t/hr	(Q2)
S/H Attemperation Flow	t/hr	(Qs)
R/H Attemperation Flow	t/hr	(Qr)
Enthalpy of MS at HPT inlet	Kcal/Kg	H1
Enthalpy at HPT Exhaust	Kcal/Kg	H2
Enthalpy at HRH at IPT inlet	Kcal/Kg	H3
Enthalpy of FW at Economizer inlet	Kcal/Kg	h1
Enthalpy of HPH Extraction Steam	Kcal/Kg	Hext
Enthalpy of FW Entering HPH	Kcal/Kg	Hin
Enthalpy of FW Leaving HPH	Kcal/Kg	Hout
Enthalpy of HPH drain	Kcal/Kg	Hdrain
Enthalpy of S/H Attemperation	Kcal/Kg	hs
Enthalpy of R/H Attemperation	Kcal/Kg	hr

1.6.2.4 Calculation of Main Steam Flow

Total steam flow (Q1) = Feed Flow (Qf)+ S/H Attemperation Flow (Qs)

Note: Care to be taken in computing Main Steam flow depending upon SH /RH Attemperation tapings.

1.6.2.5 Calculation of Reheat Steam Flow

CRH Flow (Q2) = Steam Flow (Q1) – Extraction Steam Flow (Qe) to HPH
- HP Leak Off Steam flow

a) Leak off steam flow derived from design leak off flow as per load from HBD
b) Extraction flow to all HP Heaters having Extraction From HP Turbine to be considered for computing CRH Flow

1.6.2.6 Calculation of Extraction Steam Flow

$$(Q_e) = \frac{Q_f\,(h_{fw\ out} - h_{fw\ in}) + Q_{drain\ in}\,(h_{drains\ out} - h_{drains\ in})}{(h_{ext} - h_{drains\ out})}$$

Where:

Qf = Feed Flow
h fw out = Feed Water Enthalpy at HPH Out.
hfw in = Feed Water Enthalpy at HPH in
Qe = Extraction Steam Flow
hext = Enthalpy of Extraction Steam
hdrains out = Enthalpy of Drain Out
hdrains in = Enthalpy of Drain In
Qdrain in = Drain Inlet flow

1.7 Case studies:

1.7.1 Example-1

Calculate the turbine efficiency of a condensing turbine for the following steam conditions. Assume generator efficiency at 92%.

Conditions	Flowrate, TPH	Pressure, kg/cm2 g	Temperature, oC
Inlet steam	39.13	27.0	372
Extraction	31.9	3.9	200
Exhaust	7.23	-0.96	38

Power generated from the turbine is 3.0 MW.

Ans. Enthalpy of steam at turbine inlet : 756 kCal / kg
Heat of steam at turbine inlet : 756 x 39130
: 29582280 kCal/h

Enthalpy of steam at turbine extraction (3.9 kg/cm^{2}g at 200°C) : 683 kCal / kg
Heat of steam at turbine extraction : 683 x 31900
: 21787700kCal/hr
Enthalpy of steam at turbine exhaust (-0.096 kg/cm^{2}g at 38°C) : 608 kCal / kg

Heat of steam at turbine exhaust : 608 x 7230
: 4395840kCal/hr
Theoretical power generation:

$$(29582280 - (21787700 + 4395840))/860$$

: 3.95MW
Turbine efficiency : [3.0 / (3.95 x 0.92)] x 100
: 82.6%

1.7.2 Example-2

The plant consists of coal-based single unit of capacity 300 MW each. The Boilers is natural circulation, subcritical pressure with single steam drum, single reheat, (double pass). The AFBC boilers have capacity to generate 1014 TPH (BMCR condition) steam at 178.45kg/cm2 (17.5MPa.g) (for superheated steam). Calculate boiler efficiency by indirect method?

Boiler	**Unit**	**Unit-1**
Generation	MW	303
Basis		Per kg of fuel
Data		
Type of fuel		Coal
Flue gas temperature after the APH	°C	139.4
CO_2 in flue gases	%	17.33
Ambient air temperature	°C	32.6
RH	%	76.7
Moisture content in Air	kg/kg of air	0.024
Fuel high heat value (GCV) on air dried basis	kcal/kg	3508
Composition of fuel		
Carbon	%	31.39
Hydrogen	%	1.98
Sulphur	%	0.41
Oxygen	%	13.04
Nitrogen	%	1.65
Moisture	%	15.77
Ash	%	35.77
	%	100.00

Boiler	**Unit**	**Unit-1**
Analysis		
Stoichiometric requirements - per kg of fuel		
Theoretical air requirement	kg	3.78
Theoretical CO2 %	%	20.01
Excess air supplied	%	15.30
Actual mass of air supplied	kg	4.36
Actual mass of dry flue gas	kg	4.69
HEAT BALANCE		
Heat inputs		
Through heat value of fuel	kCal/kg	3508
Total	**kCal/kg**	**3508**
Loss		
Dry flue gas losses	kCal/kg	115.09
Heat loss due to H_2 in fuel	kCal/kg	112.49
Heat loss due to moisture in fuel	kCal/kg	99.68
Heat loss due to moisture in air	kCal/kg	5.03
Heat loss due to incomplete combustion	kCal/kg	0.00
Heat loss due to surface radiation and convection	kCal/kg	60.00
Heat loss due to unburnt in bottom ash	kCal/kg	0.79
Heat loss due to unburnt in fly ash	kCal/kg	1.02
Heat loss due to bottom ash	kCal/kg	26.1
Heat loss due to fly ash	kCal/kg	28.2
Boiler efficiency	kCal/kg	3060
Dry flue gas losses	%	3.28
Heat loss due to H_2 in fuel	%	3.21
Heat loss due to moisture in fuel	%	2.84
Heat loss due to moisture in air	%	0.14
Heat loss due to incomplete combustion	%	0.00
Heat loss due to surface radiation and convection	%	1.71
Heat loss due to unburnt in bottom ash	%	0.02
Heat loss due to unburnt in fly ash	%	0.03
Heat loss due to bottom ash	kCal/kg	0.74
Heat loss due to fly ash	kCal/kg	0.80
Boiler efficiency	**%**	**87.22**

The boiler efficiency at full load is 87.22% which found to be satisfactory.

1.7.3 Example-3

Captive power plant has a boiler of capacity 135TPH and condensing type turbine of 30MW. Centrifugal type PA fan is installed of 650kW capacity and measured power consumption is 460kW which is contributing 23% of auxiliary power. PA was fan operating with suction damper 64-70% open condition. Pressure drop across damper is 150mmWC. Energy loss due to damper control is 50kW. Suggested to install Variable frequency drive (VFD) and operates based on the loading and pressure requirement for fluidisation.

Energy Savings

Present power consumption of PA fan	:	460kW
Energy Saving after installing VFD	:	45kW
Annual operating hours (24hrs x 330days)	:	7920
Annual Energy Savings	:	356,000 kWh
Annual Cost Savings (@ US$0.07/kWh)	:	$ 24900
Investment Cost (for VFD)	:	$ 35000
Simple Payback Period	:	1.40 years

1.7.4 Example- 4

In a power plant, the following are the designed and measured parameters for a clear water pump.

Particulars	Design	Operating
Flow, m^3/hr	800	576
Head, mWC	55	24 (after control valve)
Power, kW	160	124
Speed , rpm	1485	1485

The pump delivery has been throttled to about 30% (closed) manually to get the required flow rate. Normally required water flow rate is 500 m^3/hr to 700m^3/hr. Calculate the present operating efficiency and in your opinion what should be the optimum solution to get the required flow rate variation? And what would be the savings if the pump is delivering the flow rate of 550m^3/hr.
(Consider efficiency of the motor as 93%).

Ans.

$$\text{Present pump output} = \frac{Q \times H \times g}{3600 \times \eta_p \times \eta_m}$$

$$= \frac{576 \times 24 \times 9.81}{3600 \times 0.93} = 40.5 \text{ kW}$$

Pump input power = 124 kW

$$\therefore \text{ pump operating efficiency} = \frac{40.52}{124} \times 100 = 32.67\%$$

The pump is operating at a poor efficiency of 32.67% due to throttling of the flow.

Since the pump discharge requirement varies from 500 m³/h to 700 m³/h, the ideal optio would be to operate with a VSD. According to affinity laws:

$$\frac{Q_1}{Q_2} = \frac{N_1}{N_2}$$

$$\frac{H_1}{H_2} = \left(\frac{N_1}{N_2}\right)^2$$

$$\frac{P_1}{P_2} = \left(\frac{N_1}{N_2}\right)^3$$

For a flow rate 550 m³/h, the reduced speed of pump would be:

$$= \frac{550}{800} = \frac{N_1}{1485}$$

$$\therefore \quad N_1 = 1021 \text{ rpm}$$

With the reduction in speed the reduction in terms of head would be:

$$= \left(\frac{1021}{1485}\right)^2 \times 5.5 = 2.6 \text{kg/cm}^2$$

The reduction in power would be:

$$= \left(\frac{1021}{1485}\right)^3 \times 124 = 40.3 \text{ kW}$$

$$\simeq 40.3 \text{ kW}$$

$$\therefore \text{ the reduction in power} = 124 - 40.3$$

$$= 83.7 \text{ kW}$$

1.7.5 Example-5

Calcualte gross turbine heat rate

Sr No	Parameters	Unit	value
1	Generator Load MW 500	MW	500
2	MS Pressure Before ESV	kg/cm2(abs)	169.79
3	MS Temperature Before ESV	0C	538
4	HP Turbine Exhaust Pressure	kg/cm2(abs)	42.45
5	HP Turbine Exhaust Temperature	0C	340.8

Sr No	Parameters	Unit	value
6	HRH Press at IP Turbine Inlet	kg/cm2(abs)	38.2
7	HRH Temp at IP Turbine Inlet	0C	538
8	FW Press. At eco in / HPH outlet	kg/cm2(abs)	200
9	FW Temp at Eco Inlet	0C	251.1
10	Feed Flow	t/hr	1502.76
11	S/H Attemperation Flow	t/hr	0
12	R/H Attemperation Flow	t/hr	0
13	S/H Attemperation Temperature	0C	154.3
14	R/H Attemperation Temperature	0C	154.3
15	HP Leak off flow	t/hr	16.92
16	HPH Ext. Steam Temp (Heater End)	0C	340.8
17	HPH Ext. Steam Press (Heater End)	kg/cm2(abs)	42.45
18	FW Temp at HPH Inlet	0C	194.3
19	FW Temp at HPH Outlet	0C	251.1
20	Drain out temperature	0C	206
21	Drain Inlet Flow	t/hr	-
22	Inlet Drain Temperature	0C	-
23	Enthalpy at HP Turbine Inlet	kcal/kg	811.47
24	Enthalpy of HRH at IP Turbine Inlet	kcal/kg	844.04
25	Enthalpy at HP turbine Exhaust	kcal/kg	732.71
26	Enthalpy of FW at Eco. inlet.	kcal/kg	260.78
27	Enthalpy of S/H Attemperation	kcal/kg	158.27
28	Enthalpy of R/H Attemperation	kcal/kg	158.27
29	Mean Enthalpy of FW leaving HPH	kcal/kg	260.78
30	Mean Enthalpy of FW Entering HPH	kcal/kg	199.47
31	Mean Enthalpy of Extraction Steam	kcal/kg	732.71
32	Mean Enthalpy of drain Out	kcal/kg	206.56

Calculation of Main Steam Flow:

Total steam flow (Q1) = Feed Flow (Qf)+ S/H Attemperation Flow (Qs)
= 1502.76+0 =1502.76 t/hr

Calculation of Extraction Steam Flow:

$$(Q_e) = \frac{Q_f\,(h_{\text{fw out}} - h_{\text{fw in}}) + Q_{\text{drain in}}\,(h_{\text{drains out}} - h_{\text{drains in}})}{(h_{\text{ext}} - h_{\text{drains out}})}$$

Where: Qf = Feed Flow
h fw out = Feed Water Enthalpy at HPH Out.
hfw in = Feed Water Enthalpy at HPH in
Qe = Extraction Steam Flow
hext = Enthalpy of Extraction Steam
hdrains out = Enthalpy of Drain Out
hdrains in = Enthalpy of Drain In

$$= \frac{1502.76*(260.78-199.47)+0}{732.71-206.56} = 175.11 \text{ t/hr}$$

Qdrain in = Drain Inlet flow

Calculation of Reheat Steam Flow:

CRH Flow (Q2) = Steam Flow (Q1) – Extraction Steam Flow (Qe) of HPH – HP Leak Off Steam flow

= 1502.76 – 175.11 – 16.92
= 1310.73 t/hr

Turbine Cycle Heat Rate:

Turbine Cycle Heat Rate (kcal/kWh)

$$= \frac{Q_f (H_1 - h_1) + Q_s (H1-hs) + Q_2 (H_3 - H_2) + Q_r (H3-hr)}{\text{Gross Load}}$$

$$= \frac{1502.76*(811.47-260.78) + 0*(811.47-158.27) + 1310.73*(844.04-732.71) + 0*(732.71-158.27)}{500*1000}$$

$$= 1946.95 \text{ kcl/kwh}$$

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Chapter 2 Energy Performance Assessment in Cement Plant

2.1 Introduction

Cement is a material with adhesive and cohesive properties that makes it capable of bonding mineral fragment into a compact and rigid mass. Common materials used to manufacture cement include limestone, shells, and chalk or marl combined with shale, clay, slate, blast furnace slag, silica sand, and iron ore. These ingredients, when heated at high temperatures form a rock-like substance that is ground into the fine powder that we commonly think of as cement. There are more than twenty types of cement used to make various specialty concrete, however the most common is Portland cement.

Pakistan has around 25 major cement producing industries. Cement also constitutes one of the exports for Pakistan. As on March 2020, total clinker production capacity in Pakistan is 65.87 MMTPA. Coal is the major source of fuel in cement sector.

The country wise cement production for the financial year 2019 is given in table 2.1.

Table 2.1 Country wise cement production for FY 2019

Country	Production, Million MT#
China	2200
India	320
Vietnam	95
U.S.A.	89
Egypt	76
Indonesia	74
Iran	60
Russia	57
Brazil	55
South Korea	55
Japan	54
Turkey	51
Pakistan*	47

Source: https://www.statista.com/statistics/267364/world-cement-production-by-country/

* APCMA historical analysis data

2.2 Cement Production Process

Cement production processes can be categorized as dry, semi-wet, and wet processes depending on the handling of raw material before being fed to the rotary kiln. Nowadays, almost all new plants are based on the dry process and many old wet plants are also re-modelled to dry or semidry processes. The three different types of cement process is described below:

1. **Wet Process**; The wet process of cement manufacturing refers to grinding raw material into slurry after mixing with water and then feeding them into the wet process kiln for drying and calcination and finally forming clinker. The slurry's water content is usually between 32%-36%. This process is an obsolete method of manufacturing due to poor kiln heating and large water requirements.

2. **Semi-Wet Process**; It is similar to wet process where raw material powder is made into balls by adding water and directly sent to kiln for calcining.. This method is also not popular due to high levels of fuel and energy consumption and suited for materials with extreme elasticity.

3. **Dry Process**; The raw materials with different particle sizes are dried, broken and ground into powders of certain fineness and then sent into the dry process kiln for calcining, finally forming clinker. This is the most efficient energy low fuel usage as compared to the wet process, less maintenance requirements, higher kiln efficiency due to pre- heating facility and low kiln setup and maintenance costs.

The step-by-step processes involved in cement manufacturing are explained below:

Raw Materials Extraction and Crushing

The primary raw material for cement manufacture is calcium carbonate or limestone. This is obtained from the quarry where, after the removal of overburden, the rock is blasted, loaded into trucks and transported to the crusher. A multistage crushing process reduces the rock to stone less than 25 mm in diameter. Most modern cement factories are located close to a source of limestone as about 1.5 tons of limestone is needed to produce one ton of cement.

Raw meal preparation, Blending and storage

The crushed rock is stored in stockpiles where, by a carefully controlled process of stacking and reclaiming across the stockpile, blending takes place and a uniform quality of raw material is achieved. Systematic sampling and laboratory testing monitor this process. The other raw materials, normally shale, iron ore and sand, are also stored in stockpiles.

Raw milling and homogenization

Carefully measured quantities of the various raw materials are fed, via raw mill feed silos, to mills where steel balls grind the material to a fine powder called raw meal. Homogenizing silos are used to store the meal where it is mixed thoroughly to ensure that the kiln feed is uniform, a prerequisite for the efficient functioning of the kiln and for good quality clinker.

Clinkerisation

Once the homogenization process is complete, the raw mix or "kiln feed" is fed into a preheating tower. Kiln feed is heated from approximately 80°C up to 850°C, causing a series of chemical reactions that include moisture evaporating, limestone calcination and primary bonds between raw materials are created and results in clinker. To improve thermal efficiency and production capacity, a calciner vessel is added at the base of preheater tower.

Calcined raw materials are burnt at 1450°C to produce Clinker. The gas from the preheater tower is usually blended in a raw-mill, which will help stabilize the future feedstock. After flowing through the raw-mill, the gases are eventually released by a dust collector, which also obtains good particles when feedstuffs are milled. The dust will then be recycled into homogenizing silos and served as part of the kiln feed.

Cooling

Hot clinker discharge from the kiln at 1350-1450°C drops onto the grate cooler for cooling to approximately 120°C. The atmospheric air required for clinker cooling is supplied by different cooling fans into cooler chambers and pressurized through the cooler plate and clinker bed. Part of the hot air extracted from the cooler is utilized as a secondary and tertiary air for combustion in rotary kiln and combustion chamber, respectively. The cooled clinker discharges from the cooler into conveyor and transported to clinker storage and then to cement ball mill hoppers for cement grinding.

Cement grinding

Clinker along with other constituents like gypsum, limestone, etc., are fed to the cement mills. The ball mill grinds the feed to a fine powder and mill discharge is fed to a separator which separates fine and coarse product. The latter is sent to the mill inlet for regrinding and the final product is stored in concrete silos.

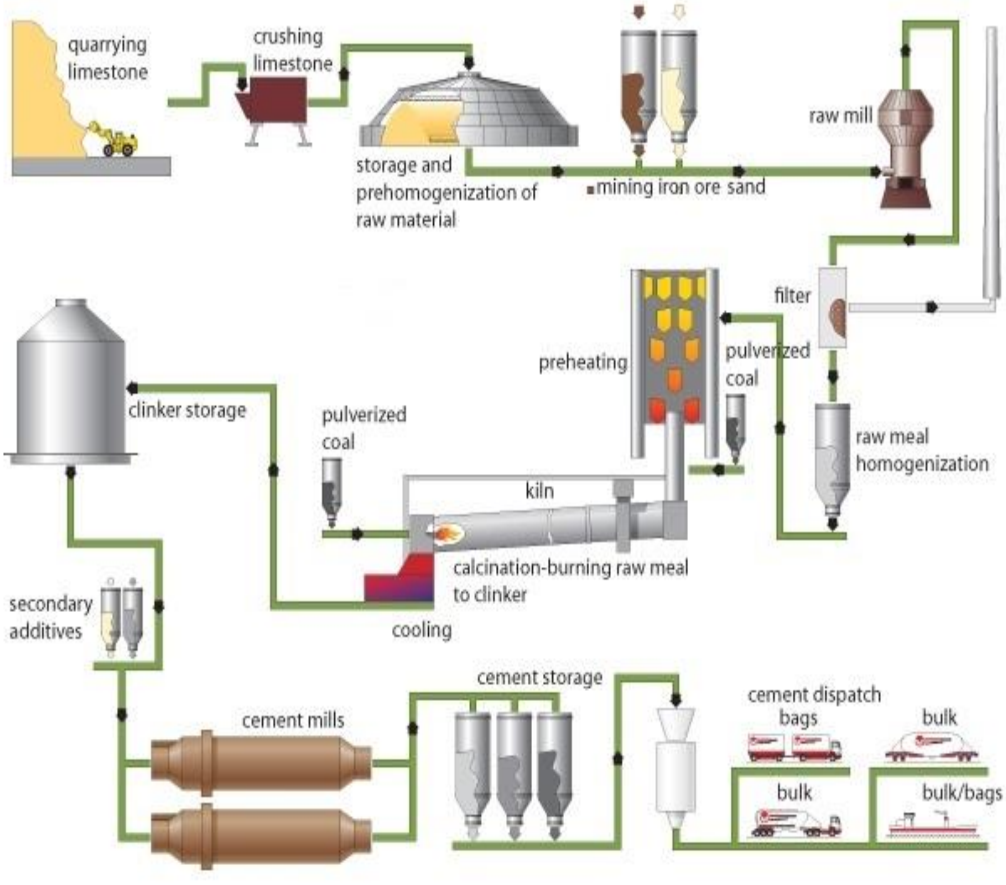


Figure 2.1 Cement Production Flow chart for Dry Process

Source: http://www.great-wall.co/media/industry-reports/2016/09/440.html#.XuyYPGgzbIU

Packing and loading

Without gypsum, cement would flash set when water is added and gypsum is therefore required to control setting times. The finished cement is stored in silos where further blending ensures consistency.

ENERGY CONSUMPTION IN CEMENT MANUFACTURING:

2.3 Material and Energy balance

2.3.1 Heat Balance of Kiln

Heat balance plays an important role in assessing various heat losses occurring during production process and helps to identify scope for energy conservation to improve overall specific energy consumption of the cement plant.

The heat input per kilogram of clinker is calculated based on various input parameters such as heat supplied by fuel, sensible heat in fuel, air (cooler air, primary air and coal conveying air), raw meal and moisture in raw meal. Table 2.2 gives the various sources of heat input.

Table 2.2. Heat input calculation equations

S.No	Heat Input	Equation
1	Heat from combustion of coal	Q1 = GCV x Mcoal
2	Sensible heat in coal	Q2 = Cpcoal x Mcoal x Tcoal
3	Sensible heat in raw meal	Q3 = Cprm x Mrm x Trm
4	Sensible heat in cooler air	Q4 = Mca x Cpca x Tca
5	Sensible heat in primary air	Q5 = Mpa x Cppa x Tpa
6	Sensible heat in coal conveying air	Q6 = Mcca x Cpcca x Tcca
7	Sensible heat from moisture in feed	Q = Mw x Cpwa x Twa

Where

GCV - Gross Calorific Value of coal, kCal/kg °C
Mcoal - Mass of coal, kg
Tcoal - Temperature of coal, °C
Cpcoal - Specific heat capacity of coal, kCal/kg °C
Mrm - Mass of raw meal, kg
Trm - Temperature of raw meal, °C
Cprm - Specific heat capacity of raw meal, kCal/kg °C
Mca - Mass of cooler air, kg
Tca - Temperature of cooler air, °C
Cpca - Specific heat capacity of cooler air, kCal/kg °C
Mpa - Mass of primary air, kg
Tpa - Temperature of primary air, °C
Cppa - Specific heat capacity of primary air, kCal/kg °C
Mcca - Mass of coal conveying air, kg

Tcca - Temperature of coal conveying air, °C
Cpcca - Specific heat capacity of coal conveying air, kCal/kg °C
Mwa - Mass of moisture, kg
Twa - Temperature of moisture, °C
Cpwa - Specific heat capacity of moisture, kCal/kg °C

Heat output calculation consists of heat of formation of clinker, heat loss through clinker at cooler outlet, dust in exhaust gas, evaporation of moisture, heat loss from preheater exhaust and cooler vent as well as the radiation and convection heat losses on the system. The respective formulas are given in table 2.3.

Table 2.3. Heat output Calculation

S.No	Heat Output	Equation
1	Heat of formation of clinker	Q8 = 4.11 Al_2O_3 + 6.48 Mg +7.648 Cao – 5.11SiO_2 - 0.59FE_2O_4
2	Heat loss through clinker at cooler outlet	Q9 = Mck x Cpc x Tck
3	Heat loss through dust in exhaust gas	Q10 = Md x Cpd x Td
4	Heat loss through evaporation of moisture	Q11 = Mw x (Hw +(Cw x Tw))
5	Heat loss through exhaust gas of preheater	Q12 = Mph x Cph x Tph
6	Heat loss through exhaust gas of cooler	Q13 = Mch x Cch x Tch
7	Surface heat losses in PH, Kiln, Cooler	$Q14 = \{h \times \Delta t^{1.25} \times Ai\} + \{4.88 \times \varepsilon \times [(Ts/100)^4 - (Ta/100)^4] \times Ai\}$
8	Un-accounted heat losses	Q15

Where

Mck - Mass of clinker, kg
Tck - Temperature of clinker, °C
Cpck - Specific heat capacity of clinker, kCal/kg °C
Md - Mass of dust, kg
Td - Temperature of dust, °C
Cpd - Specific heat capacity of dust, kCal/kg °C
Mw - Mass of moisture, kg
Tw - Temperature of moisture, °C
Cw - Specific heat capacity of moisture, kCal/kg °C
Hw - Latent heat of evaporation, kCal/kg
Mph - Mass of preheater exhaust, kg
Tph - Temperature of preheater exhaust, °C
Cph - Specific heat capacity of preheater exhaust, kCal/kg °C
Mch - Mass of Cooler exhaust, kg

Tch - Temperature of Cooler exhaust, °C
Cch - Specific heat capacity of Cooler exhaust, kCal/kg °C
h - Natural convection heat transfer rate, kCal/m^2°C, 1.97
Δt - Ts – Ta, °C
Ai - Surface area, m2
Ts - Surface temperature, °C
Ta - Ambient temperature, °C

The energy balance is done using the above equations and specific heat consumption, which is the amount of heat utilized to produce the specified amount of clinker out of the total heat input, is evaluated. The calculated major heat loss areas could be a useful input to identified waste heat recovery potential in the system.

The steps for conducting heat balance of kiln are mentioned below:

Step 1:

As seen from the above mentioned parameters, for calculation of heat input, sensible heat input through primary air and cooler air are required. Similarly for heat output calculation, heat loss through preheater exhaust and cooler exhaust are required. Thus, the air flow inlet into system through cooler fans, primary air fan and fuel injection air has to be measured and the air flow outlet of the system through cooler exhaust and pre heater top cyclone exhaust are to be measured. Air balance of the entire system is to be carried out using the measure parameters. An example of air balance in a cement plant is shown in figure 2.2 below.

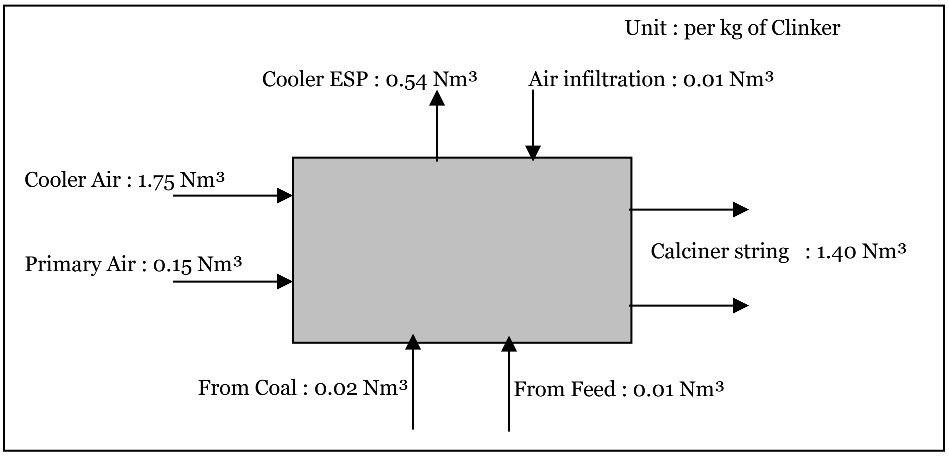


Figure 2.2: Air balance diagram

As seen from figure above, total input air is 1.94Nm^3/kg of clinker and total exhaust is also 1.94Nm^3/kg of clinker.

Step 2:

After air balance, the following data has to be measured or collected from the process system Gas Analysis

Draught system

S. No.	Location	CO_2%	O_2%	CO%	Measurement	
					Temp, °C	mmWG
1.	**Kiln inlet**					
2	**After preheater (for dry process)**					
3.	**Before de-dusting unit**					

Precalciner

Sl. No.	Description	Designed	Actual
1.	% Calcination		
2.	% of total fuel fired		
3.	% excess air		
4.	Residence time		
5.	Tertiary air temperature, °C		

(If pre-calciner is not coal fired or the coal used is different from that fired in kiln, give details of fuel/coal in terms of quality and quantity)

Clinker

Sl. No.	Description	Description	Minimum	Average
1.	Output rate (tph)			
2.	Litre weight (6 – 12 mm) (g)			
3.	Clinker temperature at cooler discharge (°C)			
4.	Sieve analysis + 30 mm (%) - 30 + 14 mm (%) - 15 + 7 mm (%) - 7 + 3 mm (%) - 3 + 1 mm (%) - 1 mm (%)			

Cooler and other

Sl. No.	Description	Temperature, °C	Pressure (mmWG)	Flow (m^3/hr)
1	Primary air (…. % of total combustion air)			
2	Secondary air			
3	Cooler Exh. Air			
4	Kiln inlet			
5	Preheater fan (inlet/outlet)			
6	Deduster (inlet / outlet)			

Other Necessary Parameters:

Sl. No.	Description	Value
1.	Kiln feed rate	
2.	Kiln output rate (Clinker)	
3.	Moisture in fine coal	
4.	Return dust in preheater	
5.	Ambient Temperature	
6.	Reference temperature	

Example: Heat Balance of a 3500TPD capacity cement plant having five stage pre heater

INPUT DATA:

Chemical analysis of Clinker

Constituents	%
SiO_2	20.98
Fe_2O4	3.97
Al_2O_3	5.27
CaO	63.3
Mg	2.52

Collected/measured data:

Description	Unit	Value
Mass of coal, Mcoal	kg/kg of clinker	0.11
GCV of coal	kCal/kg of coal	7500
Specific heat capacity of coal, Cp	kCal/kg °C	0.285
Kiln/PC fine coal temperature, Tc	°C	65
Mass of raw meal feed (Kiln feed to Clinker factor (gross)), Mrm	kg/kg of clinker	1.65
Specific heat capacity of raw meal, Cprm	kCal/kg °C	0.212
Temperature of raw meal, Trm	°C	70
Mass of cooler air, Mca	kg/kg of clinker	2.374
Specific heat capacity of cooler air, Cpca (@ ambient temperature)	kCal/kg °C	0.24
Temperature of cooler air, Tca	°C	35
Mass of primary air, Mpa	kg/kg of clinker	0.0259
Specific heat capacity of cooler air, Cppa (@ ambient temperature)	kCal/kg °C	0.24
Temperature of cooler air, Tca(@ ambient condition)	°C	35
Mass of coal conveying air, Mcca	kg/kg of clinker	0.063
Specific heat capacity of coal conveying air, Cpcca	kCal/kg °C	0.24

Temperature of coal conveying air, Tcca	°C	40
Moisture in kiln feed, Mw	kg/kg of clinker	0.0083
Specific heat capacity of moisture in kiln feed, Cpwa	kCal/kg °C	1.0
Temperature of moisture in kiln feed, Twa	°C	70
Mass of clinker, Mck	kg/kg of clinker	1.0
Specific heat capacity of clinker, Cpck	kCal/kg °C	0.262
Clinker temperature, Tck	°C	125
Mass of dust in exhaust gas, Md	Kg/kg f clinker	0.165
Specific heat capacity of dust in exhaust gas, Cpd	kCal/kg °C	0.262
Temperature of dust in exhaust gas, Td	°C	400
Mass of moisture, Mw	kg/kg of clinker	0.0083
Latent heat of evaporation, Hw	kCal/kg	540
Temperature of moisture in clinker, Tw	°C	100
Mass of exhaust gas of preheater, Mph	kg/kg of clinker	2.198
Specific heat capacity of exhaust gas of preheater, Cph	kCal/kg	0.255
Mass of exhaust gas of cooler, Mch	°C	0.917
Specific heat capacity of exhaust gas of cooler, Cch	kg/kg of clinker	0.252
Temperature of cooler, Td	kCal/kg °C	350

Solution:

Heat Input:

1. Heat from combustion of coal, Q1 = Mcoal x GCV
= 0.11 x 7500
= 825 kCal/kg of clinker

2. Sensible heat from coal, Q2 = Mcoal x Cpcoal x Tcoal
= 0.11 x 0.285 x 65
= 2.0377 kCal/kg of clinker

3. Sensible heat from raw meal, Q3 = Mrm x Cprm x Trm
= 1.65 x 0.212 x 70
= 24.486 kCal/kg of clinker

4. Sensible heat in cooler air, Q4 = Mca x Cpca x Tca
= 2.374 x 0.24 x 35
= 19.55 kCal/kg of clinker

5. Sensible heat in primary air, Q5 = Mpa x Cppa x Tpa
= 0.0259 x 0.24 x 35
= 0.2172 kCal/kg of clinker

6. Sensible heat in coal conveying air, Q6 = Mcca x Cpcca x Tcca
= 0.063 x 0.24 x 40
= 0.6048 kCal/kg of clinker

7. Sensible heat from moisture in kiln feed, Q7 = Mw x Cpwa x Twa
   = 0.083 x 1.0 x 70
   = 0.5775 kCal/kg of clinker

TOTAL HEAT INPUT = Q1 + Q2 + Q3 + Q4 + Q5 + Q6 + Q7
= 873.63 kCal / kg of clinker

Heat Output:

1. Heat of formation of clinker, Q8 = 4.11 Al_2O_3 + 6.48 Mg +7.648 Cao – 5.11SiO_2 - 0.59FE_2O_4
   = 4.11x5.27 + 6.48x2.52 +7.648x63.3 – 5.11x20.98 - 0.59 x3.97
   = **412 kCal/kg of clinker**
2. Heat loss through clinker at cooler outlet, Q9 = Mck x Cpc x Tck
   = 1.0 x 0.262 x 125
   = **32.75 kCal/kg of clinker**
3. Heat loss through evaporation of moisture, Q11 = Mw x {Hw +(Cw x Tw)}
   = 0.0083 x {540 + (1 x 100)}
   = **5.279 kCal/kg of clinker**
4. Heat loss through exhaust gas of preheater, Q12 = Mph x Cph x Td
   = 2.198 x 0.255 x 400
   = **224.325 kCal/kg of clinker**
5. Heat loss through exhaust gas of cooler, Q13 = Mch x Cch x Tch
   = 0.9717 x 0.252 x 350
   = **80.879 kCal/kg of clinker**
6. Surface heat loss from PH, Kiln, Cooler, Q14 = {h x Δt$^{1.25}$ x Ai} + {4.88 x ε x [(Tw/100)^{4} – (Ta/100)^{4}] x Ai}
   = 101.10 kCal/kg of clinker

Total Heat Output = Q8 + Q9 + Q10 + Q11 + Q12 + Q13 + Q14
= 873.63 kCal/kg of clinker

2.4 Raw mill

Raw meal preparation: The crushed limestone and corrective materials (laterite/red ochre and iron ore) are stored in a separate concrete bins. Later these are extracted through weigh feeder system and fed to the Raw Mill (Ball mill or vertical raw mill) in a required proportion to produce raw meal powder. Most modern plants are installed with Vertical Roller Mill (VRM). The hot gases from kiln pre-heater are drawn by raw mill fans and used for drying of material during grinding. Finely ground particles are entrapped in the gas stream & carried up to the classifier for the separation of particles and regrinding to get the required fineness of raw meal. The ground material is conveyed to the Clinker Feed Silo for storage and used as feed in kiln for process of clinkerisation.

The Raw mill circuit diagram

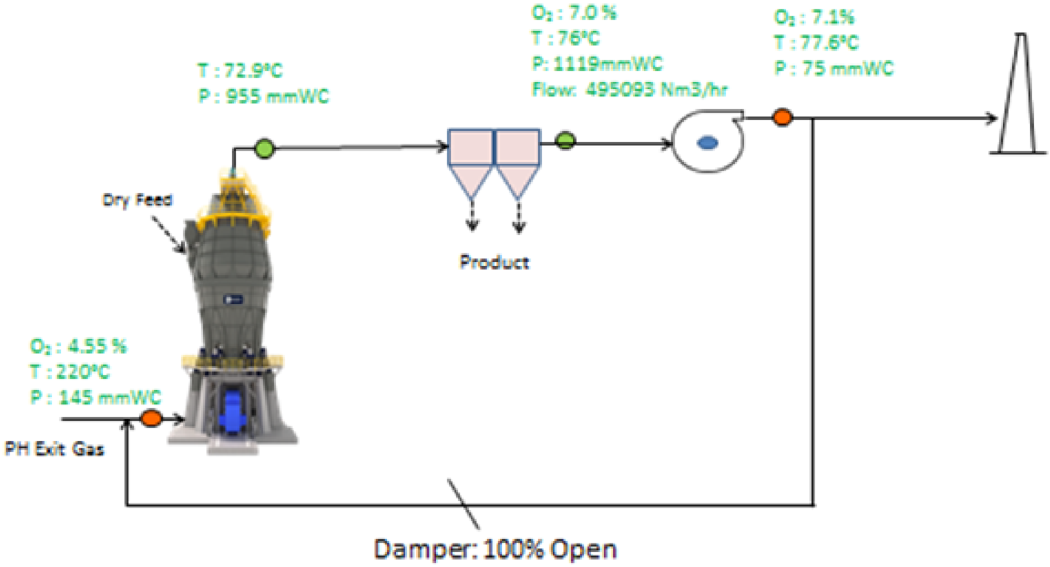


Figure 2.3: Vertical raw mill circuit

Figure 2.2 illustrates the various points along the raw mill circuit where parameters like temperature, pressure, flow and oxygen level are measured. The oxygen percentages at inlet of the mill and after the raw mill fan are used for calculating percentage of air ingress. The inlet air flow of the raw mill fan is used to calculate fan efficiency.

$$Air\ ingression\ across\ mill\ circuit = \frac{O_2\%\ at\ point\ 2 - \ O_2\%\ at\ point\ 1}{21 - \ O_2\%\ at\ point\ 1}$$

For the above figure,

$$Air\ ingression = \frac{7.1 - 4.55}{21 - 4.55} = 15.5\%$$

The Raw material feed analysis, bond index of the limestone and raw meal product analysis in the laboratory is also to be collected to obtain information about the limestone quality.

2.5 Coal Mill

Coal preparation: Coal is used as a fuel for the process of clinkerisation. Raw coal, received in raw coal hoppers from coal storage gantry, is subjected to the grinding process. Raw coal from the hoppers is fed to coal mill. Raw coal is ground into a fine powder of required fineness. For effective grinding hot air from cooler is used while grinding in VRM Mill. Hot air from preheater exhaust is also used in certain plants. The fine coal is stored in the fine coal hoppers. This is transported to fine coal bin through FK/Booster/Air compressor pump system.

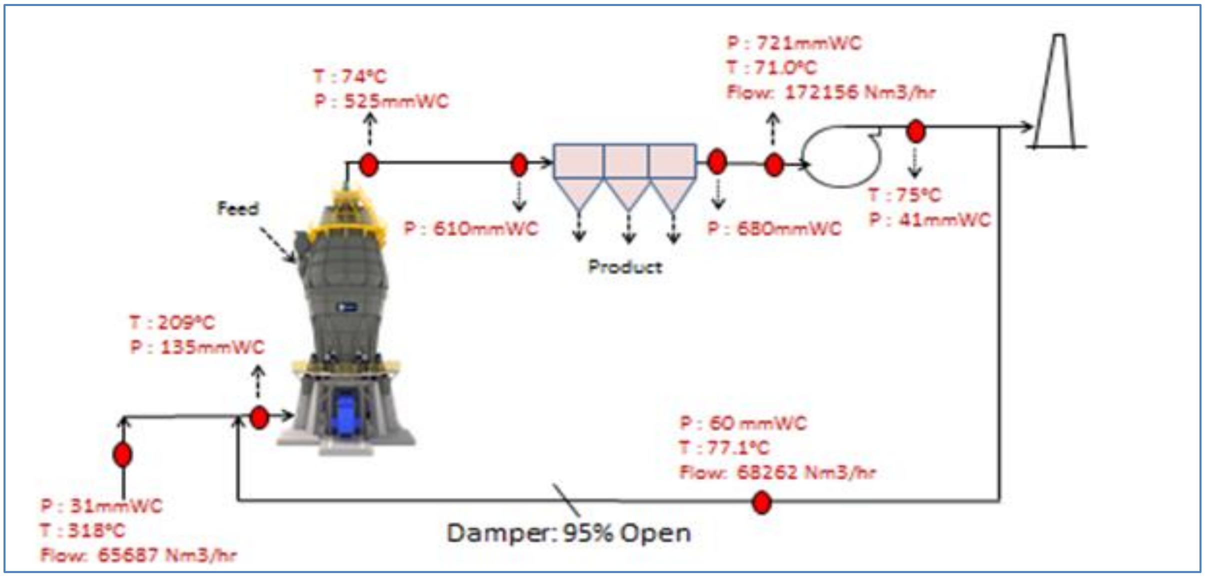


Figure 2.4: Coal mill circuit

The measurement of the flow, temperature, oxygen %, carbon mono oxide and pressure is carried out at mill inlet, mill outlet, cross the bag filter/ESP, fan, and recirculation (as shown in figure 2.3). The coal feed analysis, Hardgroove index of the coal and product analysis data is collected from the laboratory. The data is analysed towards air ingression, fan efficiency, material and energy balance

2.6 Cement Mill

Cement Grinding: Depending upon the various types of cement manufactured, appropriate additives are added to the clinker and are ground in the cement mill. The Plant can have VRM or Ball mills for grinding. The Final product with adherence of Quality norms goes to Cement Silo for proper blending & Storage.

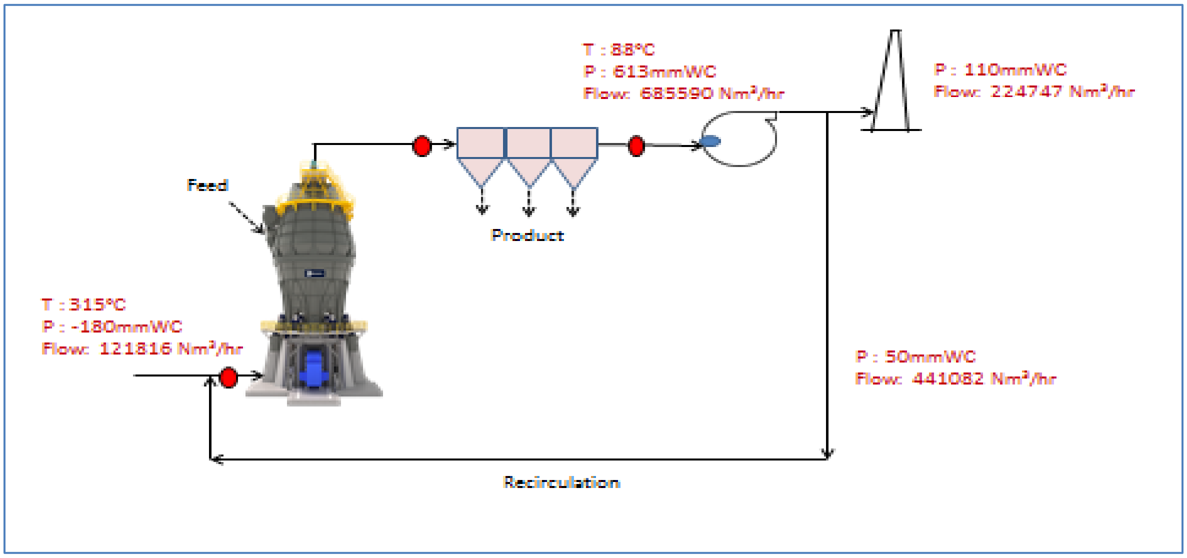


Figure 2.5: Cement mill circuit

The measurement of the flow, temperature and pressure is carried out at mill inlet, mill outlet, across the bag filter/ESP, fan, and recirculation. The clinker, gypsum, flyash materials feed analysis, Bond index of the clinker and product analysis is collected from the laboratory. The data is analysed towards air ingression, fan efficiency, material and energy balance

2.7 Energy Conservation Case Studies

2.7.1 Minimise False Air Entry:

False air entering into pre-heater exhaust gas circuit will add load on pre-heater fan and increases power consumption. By monitoring / measuring increase in O2% in exhaust gas circuit or volumetric gas flow at inlet and outlet of pre-heater (PH) fan, the false air infiltration can be quantified. By minimising the false air quantity, operating load on pre-heater fan can be reduced and power savings can be achieved.

Example 1:

In a 3500TPD plant, it was observed that false air is entering into the pre-heater exhaust gas circuit between PH Fan inlet & outlet, from dilution air inlet gates provided to minimise the temperature of gas to the fan inlet. The air filtration across PH fan is equivalent to 0.05 Nm3 per kg of clinker. The clinker production rate is 300 TPH. The static pressure developed is 4500mmWC with power consumption of 2400kW and operating efficiency of 75%. Assume the static pressure developed and efficiency of fan remains same. Calculate the power savings due to reduction in false air infiltration.

Solution:

Production rate of clinker = 300,000 kg/hr
False air infiltration = 0.05 Nm3/kg of clinker
Equivalent volume of false air infiltration = 300,000 x 0.05
= 15,000 Nm3/hr
Equivalent reduction in power consumption= 15,000 x 1500 / (3600x 102 x 0.75)
= 81.7kW
Annual Operating hours = 8000
Annual energy Savings = 653,600 kWh
Annual cost savings (PKR 5.00 / kWh) = PKR 3.268 Million

2.7.2 Replace lower efficiency PH fan with new energy efficient fan

2.7.2.1 Background

The modified & installed PH fan is old with design efficiency of 75% and operating efficiency of the fan is also found to be less efficient. The measured parameters along with evaluated fan efficiency are given in table.

Design Parameters	Units	PH fan
Air flow	m3/hr	1280000
Pressure	mmWC	700
Power	kW	2800
Actual parameters		
Temperature		258
Air flow	m3/hr	1242760
Differential pressure	mmWC	450
Power	kW	2410
Fan Efficiency	%	72%

2.7.2.2 Recommendation

It is recommended to install new efficient fan. The expected operation efficiency of new fan is around 85%.

2.7.2.3 Energy Savings

Present PH fan power consumption	: 2410kW
Reduction in power consumption	: 400kW
Annual operating hours	: 8000
Annual energy savings	: 3.2 Million kWh
Annual cost savings (@ PKR 5.0 per kWh)	: Rs 16 Million
Investment for new fans	: Rs 1.0 Million
Simple payback period	: 0.6 years

2.7.3 Reduction of clinker temperature and improving cooler efficiency by latest generation plates

2.7.3.1 Background

During the study it was observed that the temperature of the clinker discharged from cooler is more than 218◦C. The present cooler loading is 65 tpd/m^2, which is more than the standard cooler loading norm of 40-45 tpd/m^2.

The retrofit of cooler at Conventional grate area with the installation/retrofitting of latest grate plates (15 kCal).

The cooler should be able to cool the clinker to less than 160◦C. The hot clinker may damage the clinker conveying system. Moreover sometimes hot clinker may directly be fed into mill and it is difficult to control the mill discharge material temperature less than 120◦C otherwise the dehydration of gypsum would occur, causes deterioration of the cement quality. Higher water needs to be injected into the mill to reduce the mill outlet air and discharge material temperature.

2.7.3.2 Recommendations

The retrofit of cooler at Conventional grate area with the installation of latest grate plates (15 kCal).

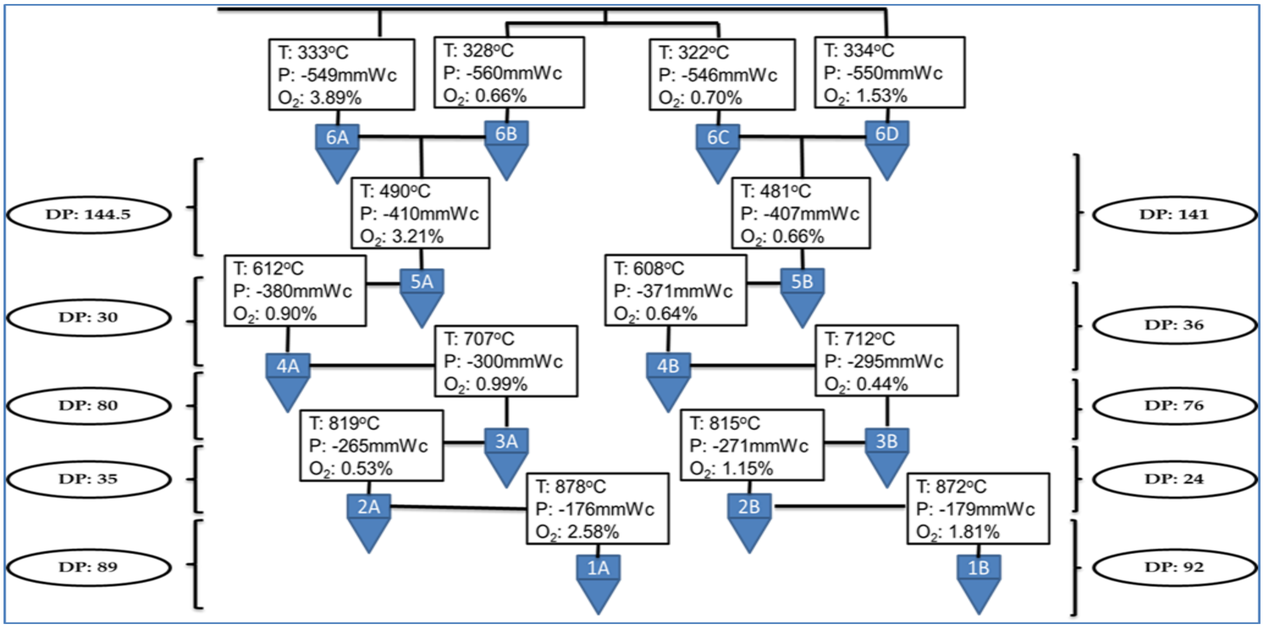
2.7.3.3 Energy Savings

Reduction in energy savings after retrofit : 15kCal/kg clinker
Annual energy savings : 8610MT
Annual energy cost savings (assuming PKR 5000 per MT): PKR 43.05 Million
Cost of implementation : PKR 40 Million
Simple payback period : 0.9

2.7.4 Reduction of pressure drop in Cyclone 6A, 6B, 6C and 6D

2.7.4.1 Background

During the energy audit study at a cement plant, high pressure drop was observed in the top cyclones 6A, 6B, 6C and 6D.



2.7.4.2 Recommendations

All top four cyclones need to be replaced with latest efficient cyclones which would result in a pressure drop of 60~80 mm wc only.

The new cyclones will have power saving in the PH fan power

2.7.4.3 Energy Savings

Average present drop in cyclones : 142 mm wc
New pressure drop estimated maximum : 80 mm wc
Difference in pressure drop : 61 mmWC
Annual energy savings in PH fan (330 days) : 792,000kWh
Annual energy cost savings (PKR 5 per Unit) : PKR 3.96 Million
Cost of implementation : PKR 11.0 Million
Simple payback period : 2.8 years

2.7.5 Waste heat recovery system

2.7.5.1 Background

During an energy audit study, it was observed that the temperature of the PH gas before the water spray is 320°C and cooler exhaust gas is more than 275°C.

After hot gas utilisation (PH and cooler exhaust gas) towards moisture reduction in the Raw materials and Coal, a potential of 8MW power generation is available.

2.7.5.2 Recommendations

It is recommended to install 9MW waste heat recovery system (when raw mill and coal mill is not in operation maximum power generation is possible).

2.7.5.3 Energy Savings

Annual energy savings 8000hrs @ 8MW : 64 Million kWh
Annual energy cost savings (PKR 5 per Unit) : PKR 320 Million
Cost of implementation for 9MW : PKR 1200 Million
Simple payback period : 3.8 years

Source:

1. All Pakistan Cement Manufacturers Association
2. TERI cement audit reports

Reference:

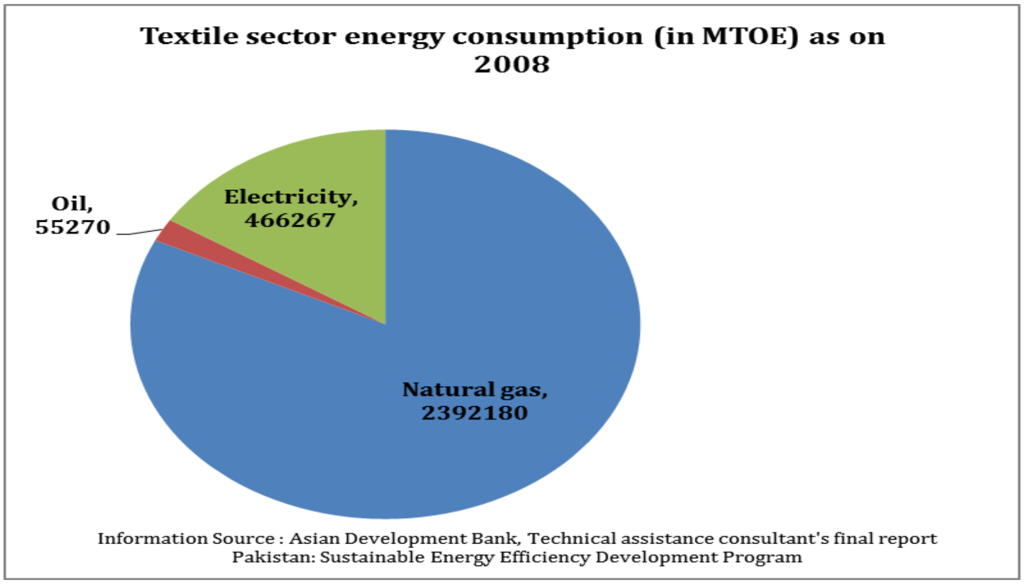
1. https://www.unido.org/sites/default/files/files/2019-05/Benchmarking%20Report%20Cement%20Sector.pdf

Chapter 3 Energy Performance Assessment of Textile Industries

3.1 Introduction

Textile Industry is one of the oldest manufacturing sectors in Pakistan with largest share of employed labour force, exports and production output. Textile sector is considered as third largest energy consumption among the industrial sector and energy cost accounts to 30 – 40% of the overall operation costs in production.

Textile sector is further classified into sub sectors: Ginning, Spinning, Weaving, Processing, Printing, Knitting, Garments, filament yarn etc. Pakistan has more than 1221 ginning units, 442 spinning units, 124 large spinning units and 425 small units for production of textiles. Please mention about the energy sources used in textile industries and then provide below figure 3.1.



Information Source : Asian Development Bank, Technical assistance consultant's final report Pakistan: Sustainable Energy Efficiency Development Program

Figure 3.1: Textile sector energy consumption in Mtoe (2008)

3.2 Textile manufacturing process

The textile industry has one of the most complicated industrial chains in the manufacturing industry. It is a fragmented and heterogeneous sector dominated by SMEs, with a demand mainly driven by three dominant end-uses: clothing, home furnishing and industrial use. Characterizing the textile manufacturing is complex because of the wide variety of substrates, processes, machinery and components used, and finishing steps undertaken.

Different types of fibres or yarns, methods of fabric production, and finishing processes (preparation, printing, dyeing, chemical/mechanical finishing, and coating), all inter-relate in producing a finished fabric. When one of these components is changed, the properties of the end product are affected. There are several properties that can be used to define a fabric. Some examples of fabric properties include weight, appearance, texture, strength, luster, flexibility, and affinity to dyestuff. Brief descriptions of the major textile processes for which the energy-efficiency measures are given here are presented in this section.

The major textile processes that are discussed in the section are:

- Spun Yarn Spinning
- Weaving
- Wet-processing (preparation, dyeing, printing, and finishing)
- Man-made fiber production

Flowcharts of the processes are also given in figure 3.2 for the better understanding of manufacturing sequences and process steps.

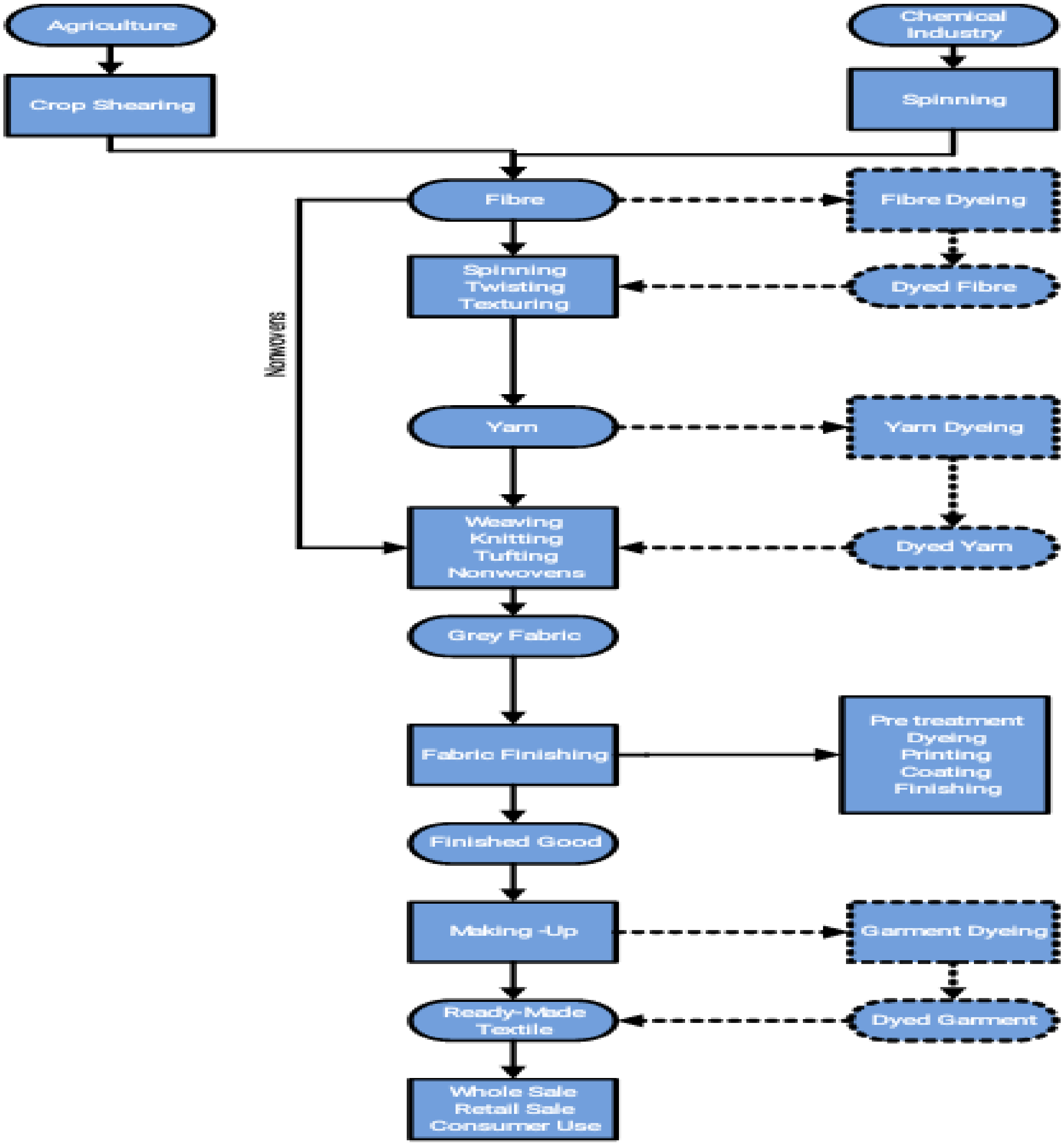


Figure 3.2 Flow Diagram- Textile Manufacturing Process

Figure 3.2 is a generalized flow diagram depicting the various textile processes that are involved in converting raw materials into a finished product. All of these processes do not occur at a single facility, although there are some integrated plants that have several steps of the process all in one plant. There are also several niche areas and specialized products that have developed in the textile industry which may entail the use of special processing steps that are not shown in Figure 3.2.

3.1.1 Spinning

In this process the raw material is converted into yarn in several steps which is provided in below figure 3.3. Yarn is then used for weaving.

Blow Room	• Opening and Cleaning • Dust Removal
Carding	• Seperating of laps • Assembled into loose Strands (Sliver)
Drawing	• Slivers are combined to form single strand • Combined slivers are separated into Roving's
Roving	• Conversion of Sliver into thick soft roving
Spinning	• Conversion of roving to yarn • Uses Ring/Rotor/Vortex spinning

Figure 3.3 Spinning Section Flow Diagram

3.1.2 Weaving

Weaving is the process of making fabric or cloth from yarns obtained after spinning process. Two sets of yarns are interlaced to form fabric. Warp is the lengthwise thread that runs from front to the back of the loom and wefts are the crosswise yarns. To prevent warp yarns from breaking, they are coated with starch like to increase the tensile strength. Looms are used for weaving fabric. Power looms and hand looms are used in textile industry for knitting.

Knitting is the process by which threads are converted to a piece of cloth. It is done by interlocking loops in which a short loop of one course of thread is wrapped over another course. Handlooms are operated manually by humans without any electrical equipment whereas Power loom make use of motors for Knitting.

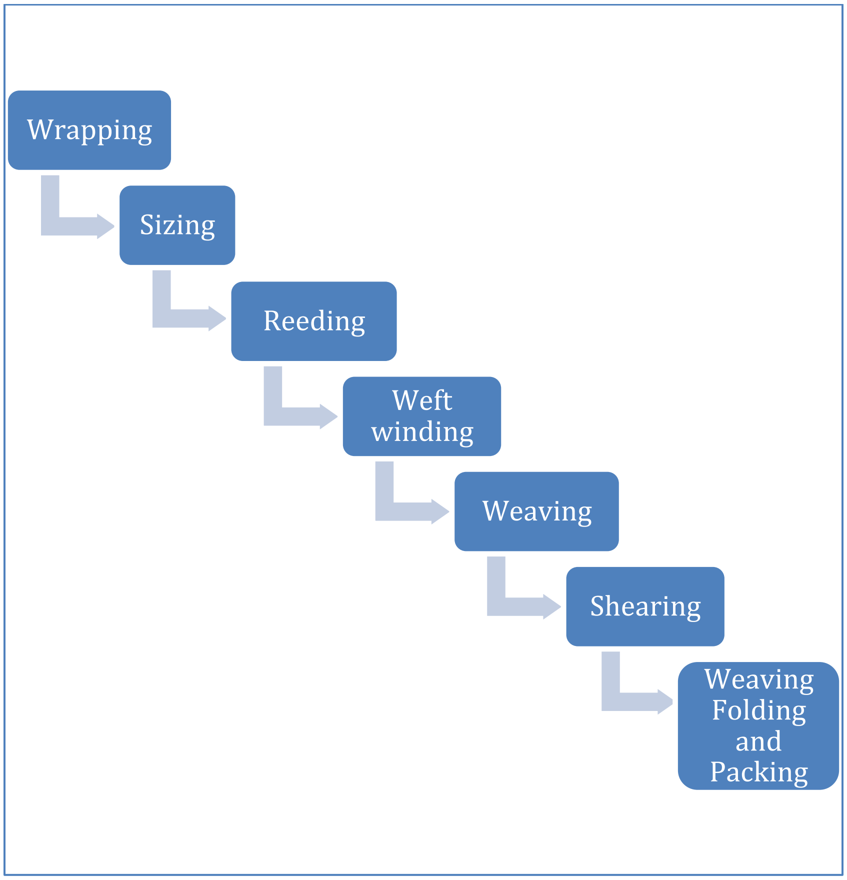


Figure 3.4 Weaving Process Flow Diagram

3.1.3 Processing

Processing is done to improve the appearance and quality of the rough fabric obtained after knitting. Wet processing consumes large quantities of water and chemicals. It is also the stage consuming the highest thermal energy in the plant. Processing include all sorts of processes that involve any sort of chemical or wet treatment. Wet processing is divided into 3 stages:

- Preparation
- Dyeing
- Finishing

Singeing	Flames are used to remove fuzzy fibers
Desizing	Removal of sizing ingredients by using solvents
Scouring	Removes impurities like wax and oil Carried out in alkaline conditions, high pressure and temperature greater than 100°C
Bleaching	Whiten fabric by using chemicals
Mercerization	Increase tensile strength and dye absorption of fabric
Dyeing	Imparts the required color to the fabric by diffusion of dye pigments
Printing	Colored patterns are printed on the surface of the fabric A final washing is also done to remove the excess colour paste and gives a uniform colour

Figure 3.5 Processing Section Flow Diagram

3.1.4 Finishing

Finishing process is done after printing to get the final product- the finished fabric. Finishing consists of Drying, Calendering and Softening:-

- Drying removes the moisture,
- Calendering gives a glossy appearance to the fabric and
- Softening softens the stiff fabric

3.1.5 Integrated textile plants

In Integrated textile plants, all the processes are done sequentially, i.e., starting from the raw material to the finished fabric is done in the same plant. Entire manufacturing process is carried out there itself.

Sizing & Weaving	• Yarn is separated into warps and wefts and warp yarn is coated with starch for strength during weaving process on Looms Desizing
Desizing	• The grey fabric's size coating is broken down by using catalysts and enzymes
Scouring	• Process to remove natural wax and non-fibrous impurities.
Bleaching	• Bleaching is done to improve the whiteness of the fabric. Increases the absorbency of the fabric for dyeing
Calendering	• Fabric is passed between heated rollers to form smooth polished fabric • Fabric is immersed in an aqueous dye bath • Vats and reactives dyes are used as well
Dyeing	• Conversion of roving to yarn • Uses Ring/Rotor/Vortex spinning
Printing	• Application of color in form of paste or ink onto the fabric's surface.

Figure 3.6 Integrated Textile Plant- Flow Diagram

3.3 Energy use in the textile industry

The textile industry, in general, is not considered an energy-intensive industry. However, the textile industry comprises a large number of plants which all together consume a significant amount of energy. In spun yarn spinning, electricity is the dominant energy source, whereas in wet-processing the major energy source is fuels. Motor driven systems are one of the major end-use energy consumers in the textile industry. Material processing has the highest share of the energy used by motor driven systems followed by pumps, compressed air, and fan systems as illustrated in the figure 3.7.

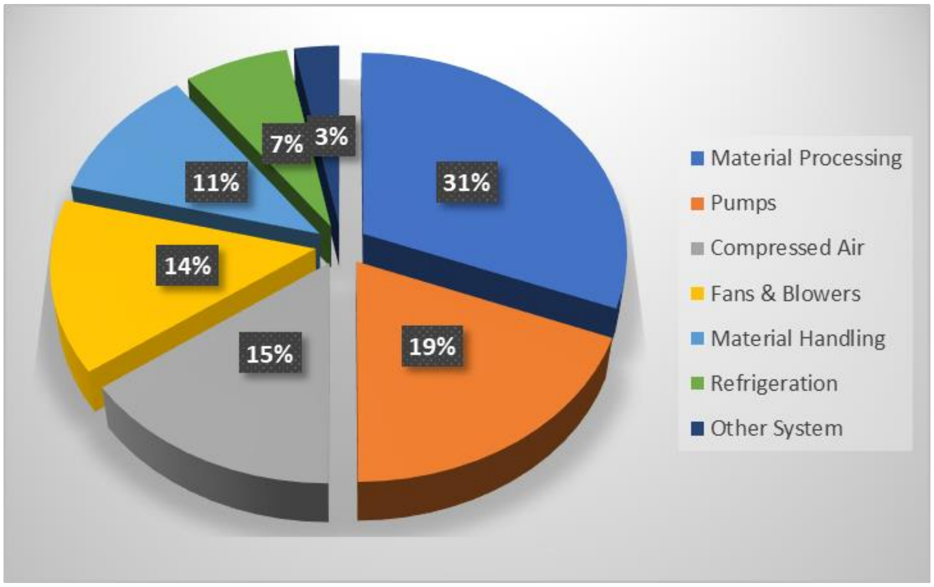


Figure 3.7 Energy Consumption shares of Motor drives

3.4 Energy use in wet-processing

Wet-processing is the major energy consumer in the textile industry because it uses a high amount of thermal energy in the forms of both steam and heat. The energy used in wet-processing depends on various factors such as the form of the product being processed (fiber, yarn, fabric, cloth), the machine type, the specific process type, the state of the final product, etc. Table 3.1 shows the typical energy requirements for textile (wet-process) processes by the product form, machine type, and process.

Table 3.1 Energy Requirements for typical Wet- Processes textile Plant

Product form/machine type	Process	Energy requirement (GJ/tonne output)
Desize unit	Desizing	1.0 - 3.5
Kier	Scouring/bleaching	6.0 - 7.5
J-box	Scouring	6.5 - 10.0
Open width range	Scouring/bleaching	3.0 - 7.0
Low energy steam purge	Scouring/bleaching	1.5 - 5.0
Jig/winch	Scouring	5.0 - 7.0
Jig/winch	Bleaching	3.0 - 6.5
Jig	Dyeing	1.5 - 7.0
Winch	Dyeing	6.0 - 17.0
Jet	Dyeing	3.5 - 16.0
Beam	Dyeing	7.5 - 12.5
Pad/batch	Dyeing	1.5 - 4.5
Continuous/thermosol	Dyeing	7.0 - 20.0
Rotary Screen	Printing	2.5 - 8.5
Steam cylinders	Drying	2.5 - 4.5
Stenter	Drying	2.5 - 7.5
Stenter	Heat setting	4.0 - 9.0

Package/yarn	Preparation/dyeing (cotton)	5.0 - 18.0
Package/yarn	Preparation/dyeing (polyester)	9.0 - 12.5
Continuous hank	Scouring	3.0 - 5.0
Hank	Dyeing	10.0 - 16.0
Hank	Drying	4.5 - 6.5

Table 3.2 gives a breakdown of thermal energy use in a typical dyeing plant (with all dyeing processes included). It gives a good idea about where the thermal energy is used, allowing the discovery of opportunities for energy-efficiency improvement. It can be seen that a significant share of thermal energy in a dyeing plant is lost through wastewater loss, heat released from equipment, exhaust gas loss, idling, evaporation from liquid surfaces, un-recovered condensate, loss during condensate recovery, and during product drying (e.g. by over-drying).

Table 3.2 Breakdown of Thermal Energy Use in a Typical Dyeing Plant

Item	Share of Total Thermal Energy Use
Product heating	**16.6%**
Product drying	**17.2%**
Waste water loss	**24.9%**
Heat released from equipment	**12.3%**
Exhaust gas Loss	**9.3%**
Idling	**3.7%**
Evaporation from liquid surfaces	**4.7%**
Un-recovered Condensate	**4.1%**
Loss during condensate recovery	**0.6%**
Others	**6.6%**
Total	**100%**

3.5 Performance evaluation of process equipment

The major energy consuming equipment in textile processes are ring frames, carding, winding and blow room machinery. Since the ring frame is single largest consumer, the performance monitoring is limited to ring frame. Similar approach can be adopted for other equipment. In the wet process the energy intensive equipment are stenters and dyeing machines, performance evaluations of these equipment are given in this section. Figure 3.8 shows the Breakdown of final energy use in a sample spinning plant that has both ring and open-end spinning machines.

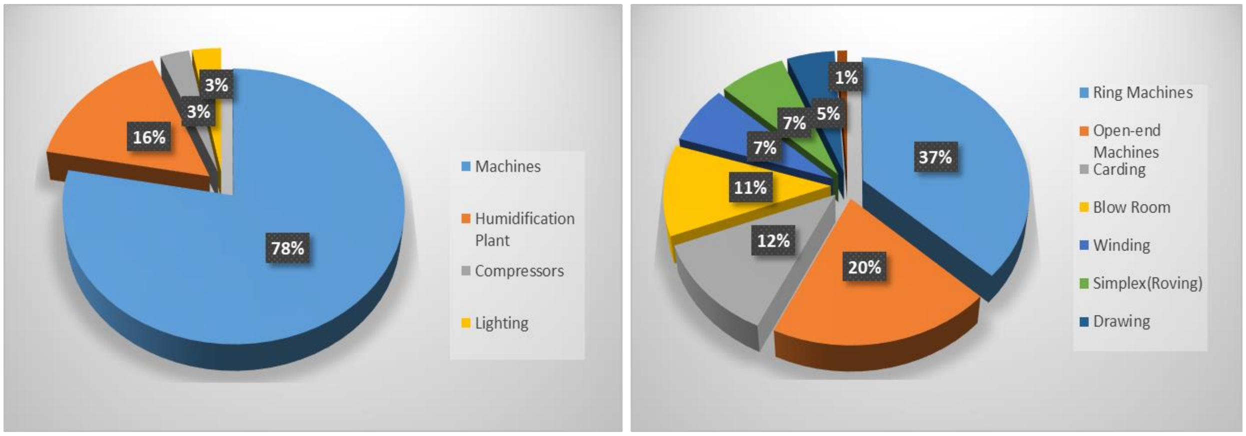


Figure 3.8 Breakdown of Final Energy use in Spinning Plant

3.5.1 Performance Evaluation of Ring Frame

Electricity is the major type of energy used in spinning plants, especially in cotton spinning systems. If the spinning plant just produces raw yarn in a cotton spinning system, and does not dye or fix the produced yarn, the fuel may just be used to provide steam for the humidification system in the cold seasons. Therefore, the fuel used by a cotton spinning plant highly depends on the geographical location and climate in the area where the plant is located.

The energy consumption for spinning different types and counts of yarn was calculated and the results are shown in Table 3.3. For all types of fibers, finer yarn spinning consumes more energy. That said, yarns used for weaving involves more twisting than yarns used for knitting. Also, production speed is low for weaving yarn compared to that of knitting yarn. As a result, with the same yarn count, more energy is consumed for weaving yarn. Also, for the same yarn count, the energy consumption for combed yarn is higher because of the additional production step (combing).

Table 3.3 Typical Specific Energy Consumption (kWh/kg) for Yarns with Different Yarn

Yarn Count (tex)	Typical Specific Energy Consumption (kWh/kg)			
	Combed Yarn		Carded yarn	
	Knitting	Weaving	Knitting	Weaving
37	1.38	1.63	1.34	1.62
33	1.58	1.88	1.54	1.86
30	1.79	2.12	1.73	2.09
25	2.19	2.60	2.11	2.55
20	3.06	3.64	2.96	3.57
17	3.89	4.62	3.74	4.53
15	4.42	5.25	4.23	5.12
12	5.52	6.81	5.52	6.72

Source: Counts and Final Use (Weaving vs. Knitting) (Koç and Kaplan, 2007)

Calculation of energy consumption of Ring machines:

Since the highest energy consumption occurs in spinning machines during yarn manufacturing, many studies have been carried out on the energy consumption of spinning machines. One of these studies shows that specific energy consumption in a ring spinning machine can be calculated with the equation given below.

$$SEC = 106.7 \times F^{-1.482} \times Dr^{3.343} \times (n/1000)^{0.917} \times \alpha text^{0.993}$$

Where;

SEC : specific energy consumption (kWh/kg) in a ring spinning machine
F : the linear density of yarn (tex);
Dr : the diameter of the ring (m);
n : the speed of the spindle (1000 r.p.m.);
αtext : the twist factor of the yarn.

However, there might be difference between the calculated and actual values that is attributable to the difference in parameters such as speed, waste ratio, mechanical efficiency and energy loss of ring spinning machines.

3.5.2 Motor Performance Monitoring

Textile industry consists of many motor drives with capacity starting from fraction of kW. The loading analysis of motor drives need to be carried out for identifying the potential of energy saving like star mode operation, soft starter, retrofitting with variable frequency drives and replacement with energy efficient motor.

3.5.3 Performance Evaluation of Stenter

Stenters have an important role in the dyeing and finishing of fabrics. Stenters are mainly used in textile finishing for heat-setting, drying, thermosol processes and finishing. It can be roughly estimated that, in fabric finishing, the fabric is treated on average 2 – 3 times in a stenter. A stenter essentially consists of a pair of endless traveling chains fitted with clips of fine pins and is carried on tracks. The cloth is firmly held at the selvages by the two chains which diverge as they move forward so that the cloth is brought to the desired width. Similar to heat setting and curing, stenters also affect the finished length, width and properties of the fabrics. Fabric can be processed at speeds from 10 – 100 m/minute and at temperatures of more than 200°C. Stenters can be heated in a variety of ways, such as direct gas firing and through the use of thermic fluid systems. Gas-fired stenters are highly controllable over a wide range of process temperatures.

Thermic fluid heating for stenters requires a small thermic oil boiler (usually gas-fired) and its associated distribution pipeline. This system is less efficient than direct gas firing and has higher capital and running costs. However, like gas, it can be used over a wide temperature range, but the problem is that this heating can only be done indirectly via a heat exchanger. This system, compared with indirect gas firing, is relatively inefficient, so it is no longer commonly used. Finally, there are a number of steam-heated stenters. Because of their low temperature limits (usually up to a maximum of 160°C) these stenters can only be used for drying; they are not suitable for heat setting or thermo fixing of fabrics.

In all stenters the hot air is blown against the fabric and then recirculated. A fraction of this air is exhausted and made up with fresh air. To provide better control, stenters are split-up into a number of compartments, usually between two and eight. Figure 3.9, shows a stenter with three-meter sections, each fitted with a temperature probe, burner/heat exchanger, fans, exhaust and damper.

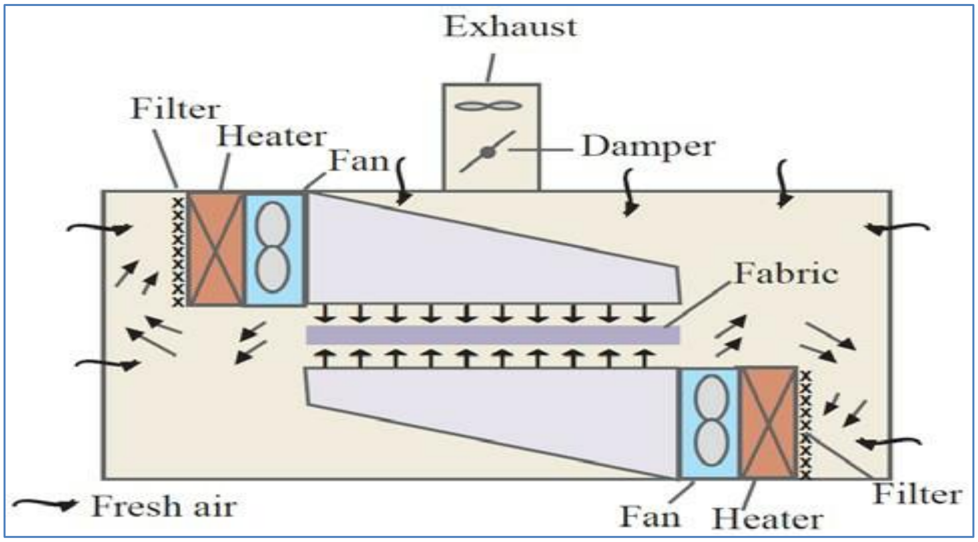


Figure 3.9 Schematic of the Air Path within a Stenter (CII, 2006)

A typical energy breakdown for a stenter being used for hot-air drying is shown in Table 3.4. By far the greatest users of energy are the evaporation and air heating components. It is therefore necessary that the fabric moisture content is minimized before the fabric enters the stenter, and that exhaust airflow within the stenter is reduced. Many stenters are still poorly controlled, relying on the manual adjustment of exhausts and operator estimations of fabric dryness

Table 3.4 Energy Breakdown for a Typical Stenter machine

Component	Energy use (GJ/tonne of product	Share of energy use from total energy use
Evaporation	2.54	41.00%
Air heating	2.46	39.70%
Fabric	0.29	4.60%
Case	0.39	6.30%
Chain	0.09	1.50%
Drives	0.43	6.90%
Total	6.2	100%

Efficiency of Stenter machine can be evaluated by measuring of moisture content in material before and after the dryer to estimate total moisture removal from the substance. The energy required to evaporate this moisture is termed as useful energy spent in the dryer. Major parameters to be measured for evaluating the dryer efficiency are Temperature (°C), moisture content of material at inlet and outlet of dryer (kg moisture/kg bone dry material), Mass flow rate of dried material (kg/hr) and measure of input thermal energy to dryer (kcal/hr) in the form of hot air input/steam/electrical heating through various direct measurement or from quantity of fuel and combustion efficiency. By measuring the total input heat energy to the dryer, the dryer efficiency is estimated.

$$Dryer\ \ Efficiency\,\% = \frac{Material\ Flow\ x\ (Moist.input\ \ -\ Moist.output\ )x[(Temp.out - Temp.in) + 540]}{Thermal\ energy\ Input}$$

Performance Evaluation of Dyeing Machine

Dyeing is the application of color to the whole body of a textile material with some degree of color fastness. Textiles are dyed using continuous and batch processes and dyeing may take place at any of several stages in the manufacturing process (i.e., prior to fiber extrusion, while the fiber is in staple form, to yarn, to fabrics, and to garments). Various types of dyeing machines are used for both continuous and batch processes. Every dye system has different characteristics in terms of versatility, cost, tension of fabric, use of carriers, weight limitations, etc. Dyeing systems can be aqueous, non-aqueous (inorganic solvents), or use sublimation (thermosol, heat transfer). Hydrophilic fibers such as cotton, rayon, wool, and silk, are typically easier to dye as compared with hydrophobic fibers such as acetate, polyesters, polyamides, and polyacrylonotriles.

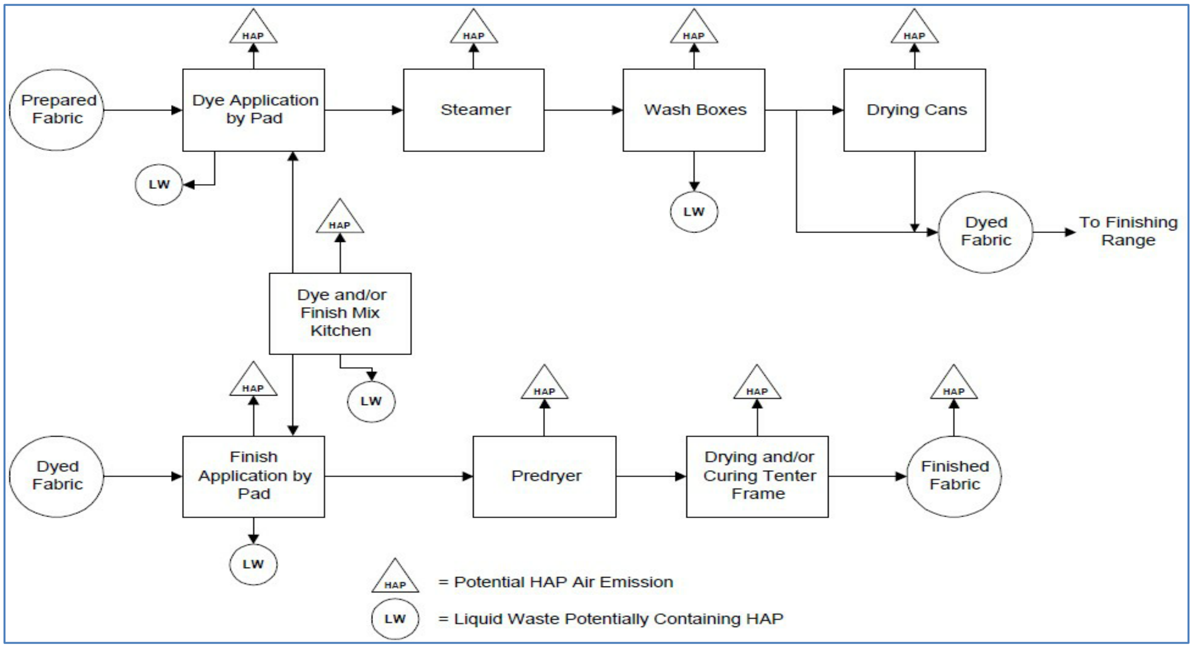


Figure 3.10 Typical fabric Dyeing and Finishing Process

Different types of machines used in the aqueous dyeing of textile fabrics are open width Jigger dyeing, Jet dyeing, rope form winch dyeing etc. These are operated at atmospheric pressure or higher pressure and temperatures below or above 100°C depending on the substrate being dyed. The major energy usage in dyeing is thermal energy in the form of steam. The bath liquor ratio may vary from 1:4, 1:6 to 1:10 or higher (i.e. 1kg of textile material to 4,6 to 10 litres of water on weight ratio) based on the dyeing types (batch/continuous). The dye color and chemicals are mixed in the water heated by steam.

Table 3.5 Effect of material-to-Liquor ratio on consumption of steam

Liquor Ratio	Steam kg per kg of fabric	
	Remazol Dyes (40^{o}C)	Disperse Dyes (130^{o}C)
1:4	1.00	1.80
1:6	1.60	2.65
1:8	2.00	3.60
1:10	2.60	4.40
1:12	---	5.30
1:20	5.35	---

Table 3.6 Energy Requirement for dyeing cotton fabrics

Process	Liquor Ratio	Temperature (^{o}C)	Energy MJ/kg		
			Dyeing	Washing	Total
Winch, hot reactive	1:2	80	8.1	7.8	15.9
	1:3	11.5	11.5	11.3	22.8
Winch, direct	1:2	95	9.7	0.4	10.1
	1:3	95	13.1	0.4	13.5
Winch, cold reactive	1:2	30	2.3	7.8	10.1
	1:3	30	3.0	11.3	14.3
Closed Jig, direct	1:2	95	1.8	0.0	1.8
	1:3	95	2.3	0.0	2.3
Closed Jig, cold reactive	1:2	30	0.4	3.9	4.3
	1:3	30	0.7	3.9	4.6
Closed Jig, Hot reactive	1:2	80	1.8	3.9	5.7
	1:3	80	2.0	3.9	5.9

Dyeing requires steam to heat the liquor to the requisite temperature and maintain the temperature for a specific period of time.

Energy Input: is calculated in the following ways:

a) Steam flow rate can be calculated by collecting the quantity of steam condensate for a specified time period.
b) Enthalpy of steam can be drawn from the pressure of steam using steam table/Mollier chart.

Energy Output: is calculated in the following ways:

a) The heat absorbed by the fabric and vessel
b) The heat taken by the liquor
c) The heat through radiation and convection by machine surface
d) Heat in the vapours

Heat load = $(M_l \times Cp_l \times \Delta t_l)$ + [10% of (b)]
Where, Ms: Mass flow rate of steam
M_l : Mass of liquor
Cp_l : Specific heat capacity of liquor
T : Temperature difference between initial and final liquor temperatures.

3.6 Performance evaluation of utilities

Textile industries will have multiple utility for providing services, based on the specific process operations. Major utility systems that are commonly used in textile industrial operations are listed below:

- Natural gas
- Electricity
- Steam
- Thermic fluid
- Compressed air
- Humidified air
- Water
- Effluent treatment plant

Captive power plant:

During initial days until 2010, with abundant availability of indigenous gas reserves, Government had established countrywide supply network and encouraged the use of natural gas in all sectors of economy including power generation and industrial activities. Even textile industries had taken this advantage for meeting their energy requirement in the power and thermal energy demand specifically for steam and indirect heating. Plant would receive piped natural gas from regional network with integration of meters for monitoring the gas consumption and fuel gas skid (inside plant premises) to remove any contaminants and pressure regulation of gas before supplying to thermal combustion equipment.

Over the years, with demand and supply gap of natural gas due to increased consumption, quicker depletion of existing gas reserves, availability during peak seasons i.e. winters was extremely difficult and forced the industries for depending on alternative energy sources such as grid electricity, furnace oil and diesel.

Various capacities of captive or co-generation power plants were installed in the respective textile industries based on process demand. For enhanced efficiency these systems will be integrated with waste heat recovery such as steam generation and thermic fluid heating from exhaust flue gases.

During the operation of captive power plant, it is very essential to monitor various operating parameters such as power generation, fuel consumption, fuel composition, calorific value, combustion indicators such as O2 / CO2, NOx & CO in flue gas, different zone temperature variations, flue gas temperatures, and heat recovery unit temperature / pressure etc.

Based on the monitored / measured operating parameters and methodology provided in Book 4 – Power plant systems, performance evaluation of gas engine for one of the typical textile industry is given below in table 3.7.

Table 3.7: Performance evaluation of gas engine in typical textile industry

S. No	Parameters	Unit	Value
A	Input – Natural Gas (A)	Million kCal (kW)	6.59 (7662)
	Quantity of Natural Gas	Sm^3 / h	690
	Net Calorific Value	kCal / Sm^3	9550
B	Out Put – Electrical & Thermal (B)	kW	2786 + 514
1	Electricity output	kW	2786
2	Thermal Fluid Heat Recovery Unit (HRU)	kW	514
	Quantity of Circulation,	TPH	50
	Heat to raise temp. Input/output	^0C	289 / 307
3	High Temperature Water (Heat Losses)	kW	1911
	HT water Circulation across Radiator	m^3/h	39
	Inlet / Outlet Temperature across radiator	^0C	84 / 41
4	Low temperature Water (Heat Losses)	kW	372
	Cooling water flow across LT water PHE	m^3/h	40
	Inlet / Outlet Temperature across PHE	^0C	21 / 28
5	Exhaust Flue Gas & other losses (difference)	kW	1706
	Exhaust Flue Gas flow (estimated)	kg/h	44123
	Inlet / Outlet Temperature across HRU	^0C	435 / 317
C	**Efficiency of Gas Engine {B/A X 100}**	**%**	**43.1**

From the above table it can be seen that electrical efficiency is on lower side mainly due to part load operation. Flue gas temperature even after the Heat Recovery Unit is very high (>300^oC) which indicates significant heat losses that needs to be reduce for increasing the gas engine thermal efficiency.

Electricity:

As mentioned, during earlier days many textile industries were designed to meet their electricity demand from their own gas fired captive power plants. Off late, with decreased natural gas availability, plants are relying on regional grid electricity and diesel generator sets during exigencies or power outages.

Each industry's electrical system will mainly comprise of HT feeders, power transformers, step down transformers, distribution network cables upto MCC and PCC terminals, along with protective gear assemblies, etc.

With adequate energy metering systems across different sections of the plant, monitoring of electrical system parameters such as MD recorded, energy consumption (kWh), peak load, Voltage, amp, PF, kW, kVA, Hz is essential for performance evaluation of electrical system as per the methodology given in Book 3 – Chapter 1 electrical system.

Increasing trend in grid electricity tariff, power quality issues coupled with interruptions has undesirable effect on production and overall operation costs. Hence, plant has to ensure the following energy efficiency measures at higher priority.

- Optimal loading of transformer to maintain the best efficiency point.
- Demand management and strategic planning to avail the TOD benefits.
- Effective power management with installation of capacitors and reactive power compensation.
- Harmonics level monitoring for enhancing the power quality.
- Maintaining the voltage drop and distribution losses at minimal levels.

Steam

Steam is utilized in the textile industries mainly for wet processing operations. Boilers are commonly installed for steam generation and capacities of the same are based on thermal energy demand required by plant. As mentioned in the earlier books, different types of boilers are installed depending on the multiple factors such as fuel considerations, steam pressure, efficiency, space, cost, environmental regulations, etc., However, in most of the textile process, average steam demand is in the range of 0 – 20 TPH at maximum utilization pressure and temperature of 7.5 Kg/cm^2 and 170^{o}C. In co-generation power plant, exhaust steam from steam turbine or waste heat recovery boiler is sent for textile process to meet thermal energy requirement.

Some of the major operating parameters essential to monitor during the operation of boiler, are given in below table 3.8.

Table 3.8: Major operating parameters to be monitored for boiler study

Sl. No	Particulars	Units	Design	Actual
1	Evaporation rate	*TPH*		
2	Boiler drum pressure (design @ MCR)	*Kg/cm^2*		
3	Deaerator pressure	*Kg/cm^2*		

4	Boiler steam outlet pressure @ MSSV	*Kg/cm^2*
5	Boiler steam outlet temperature @ MSSV	*^oC*
6	Fuel fired	-
7	Fuel consumption	*Kg/h*
8	Fuel GCV	*kcal/kg*
9	O_2 or CO_2 in exhaust flue gas	*%*
10	Boiler Feed Water Temperature	
11	Combustion air temperature	
12	Firing zone combustion air pressure	*mmWC*
13	Flue gas pressure at Furnace exit	*mmWC*
14	Flue gas pressure at ID fan inlet	*mmWC*
15	Flue gas temperature at furnace exit	*^oC*
16	Flue gas temperature at Economizer outlet	*^oC*
17	Flue gas temperature at APH outlet or ESP inlet	*^oC*
18	Flue gas temperature at ESP outlet or ID fan inlet	*^oC*
19	Make up water consumption	*kg/h*
20	Condensate recovery	*kg/h*

Based on the monitored / measured operating parameters, refer Book 2 - for methodology to performance evaluation of boiler system (Direct and Indirect Efficiency testing).

Example for direct efficiency in one of the textile plant, where Indonesian Coal was fired to produce the steam at 7 bar & 162^{o}C is given below.

$$\text{Boiler Efficiency } (\eta) = \frac{6000, kg/h \ x \ (662 - 32), kcal/kg}{1200, kg/h \ x \ 4930, kcal/kg} \ x \ 100$$

Boiler Efficiency (η) = 63.89 %

In another example of indirect efficiency testing, one textile plant was firing dual fuel based on the availability and local pollution control board (PCB) restriction for coal combustion leading to use of biomass such as rice husk to maximum possible extent. Steam generation of 7.8 TPH at saturation pressure of 8.5 Kg/cm^2 (respective temperature ~495^{o}C) with PCB's permission for coal firing only 4 days in the month (i.e., 15% of total husk fired in the month). Comparative details of the efficiency evaluation summary are given in below table 3.9.

Table 3.9: Efficiency evaluation of boiler while firing coal and while firing rice husk

Particulars of operating boiler	**Coal firing**		**Husk firing**	
	kCal	%	kCal	%
Heat input from the fuel	***5180***	***100***	***3526***	***100***
Output Heat losses				
Dry flue gas losses (L_1)	343.4	6.63%	279.7	7.93%

Heat loss due to H_2O formation from H_2 in fuel	218.1	4.21%	310.2	8.80%
Heat loss due to moisture in fuel	100.5	1.94%	45.2	1.28%
Heat loss due to moisture in air	11.0	0.21%	9.8	0.28%
Heat loss due to unburnt in fly ash	0.7	0.01%	3.4	0.10%
Heat loss due to bottom ash	39.1	0.76%	39.1	1.11%
Heat loss due to fly ash	6.2	0.12%	6.2	0.18%
Heat loss due to surface radiation	*104*	*2.01%*	*78*	*2.21%*
Boiler Efficiency	**4357**	**84.11%**	**2754**	**78.12%**

From the above table, it can be observed that boiler operating efficiency is found to be higher during coal firing mainly due to better calorific value and ease of operation.
Boiler system also comprises auxiliary equipment such as pumps (for the boiler feed water, make-up water and condensate transfer) and fans (forced draft – primary/secondary and induced draft). However, their energy consumption will be normally on lower side and scope for energy efficiency is limited.

Steam is generated at 7 – 7.5 Kg/cm^2 pressure and mainly used in the dyeing section for indirect heating applications (High Temperature and High Pressure machines, dryers, bleaching, boil-out systems, etc.).

Plant has installed steam flow meter in the main steam line along with steam totalizer and monitoring the steam consumption on hourly basis. Apart from it, steam is also utilized in canteen and yarn-conditioning units of mill # 1 and mill # 2.

Steam from boiler is transported to various user ends of wet processing operations through Pressure Reducing Stations / Valves and then utilized either directly or for indirect heating. Pipelines should be adequately sized from the main header and distribution network to maintain the minimal pressure drop.

Steam Utilization

The major steam utilisation areas are sizing machines, dye plant, calendars and sucker sizing machine. The sizing machine and the dye plant consume the maximum quantity of steam.

Vertical Dyeing Range Machines: Multiple cylinders will be in operation with inlet steam temperature of 133 - 145^{o}C and process temperature maintained at 116-120^{o}C. Design steam pressure of VDR cylinder is 3.5 kg/cm^2 and steam consumption depends on number of cylinders in line.
Jigger Machines: These machines are manly for special quality products with alternate cycles of cold wash and steam bath. These are designed for direct steam injection at 132^{o}C. Steam pressure range is from 3 to 5.0 kg/cm^2 at maximum temperature conditions of 155^{o}C.

Stenter: These machines are equipped with multiple cylinders for indirect steam heating of fabric with stretching process. Normally inlet steam temperature of 134^{o}C is minimum and process temperature maintained at 116-125^{o}C.

Bleaching (JT10): These machines are used for carrying out bleaching of the dyed clothing. Direct steam is used into bath with temperature of 75 – 90°C. Chemicals are sprayed for JT10 rollers and Bath remains are drained to ETP at 60°C - 75°C.

Hank Dyeing: These machines are used for yarn conditioning in batch operation of 12 hours with indirect steam at 2.5 kg/cm^2 intermittently to maintain process temperature of 85°C.
VAT: These machines designed for direct steam utilization along the perforated pipelines. Operation of VAT machine depends on process requirement normally around 65-80°C bath temperature with input steam at 2.5 kg/cm^2 and bath condensate drain was sent to ETP.

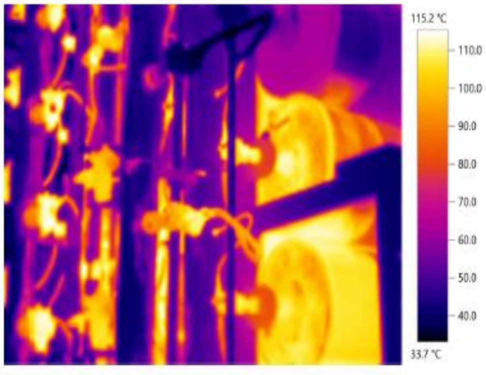
Circular Dryers: These machines are designed for moisture removal from the dyed fabric. Wet yarn is subjected for drying with steam at 2.5 kg/cm^2, 124°C for indirect heating of air through the radiator coils and exhaust fan for venting of moisture rich air.

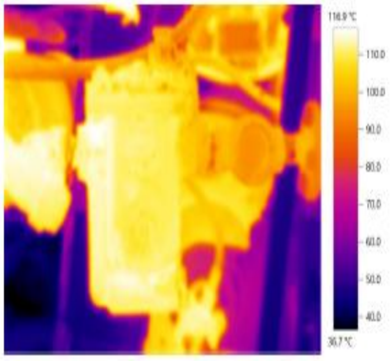
Box and Tumble driers: These machines operation are also similar to circular dryers with steam at 2.5 kg/cm^2 for the indirect heating of air in radiator coils.

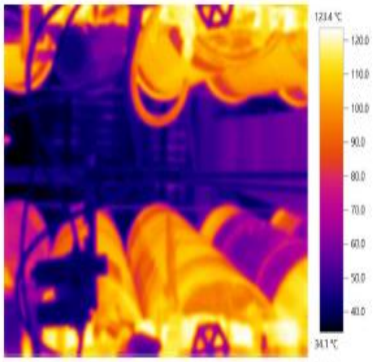
Sizing machine: The yarn is sprayed with starch. It is then passed into the sizing machines for drying. A set of multiple cylinders are used in the machines for drying. Steam is passed into these driers at 4 kg/cm^2 and the condensate is removed with the help of siphons and steam traps. The condensate from the sizing machines is collected in an overhead tank.

Calender felt: Calender felt is designed for one steam cylinder and 2 bolts it is operated for 10-12 hours in a day. Steam at 2.5 kg/cm^2 is used in cylinders for moisture control, shining, evenness and smoothness of the cloth. Condensate is removed using siphons & steam traps.
Majority of textile industries are commonly found to be installed with steam traps of ball float, thermodynamic (including new compact module) and inverted bucket type depending on the steam and condensate loads. Apart from that it will be subjectively decided on the multiple factors such as type, size, load, temperature of discharge, manner of installation, sensitivity to thermal shock and load variations, air venting, etc., vis-à-vis fitted already in the mills steam distribution lines.

It is suggested to carry out regular survey of steam traps for their effective working along with insulation survey. Some of sample thermography images captured in one of typical textile industry are given in below figure.







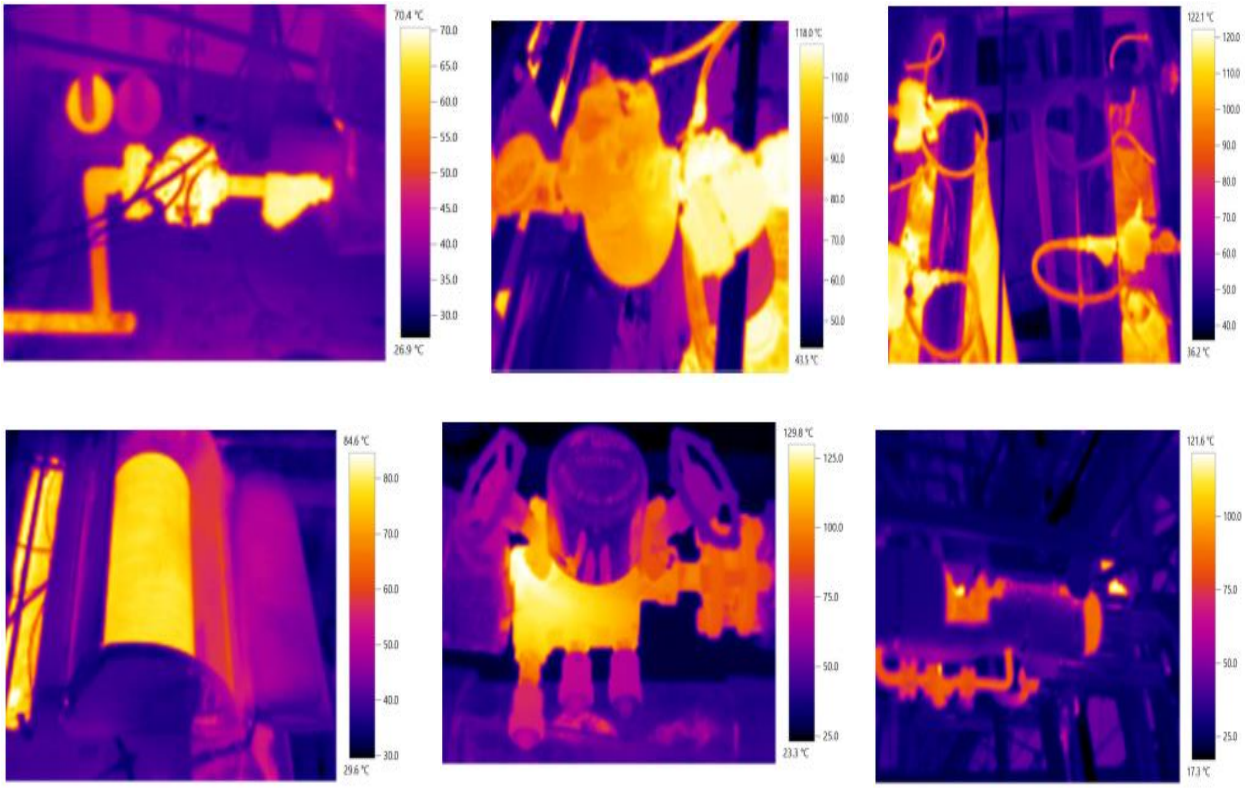


Figure 3.11 Thermography images of steam and condensate survey

The condensate from indirect process heating areas are collected in tank through pipeline and passes through flash vapour vessel. Recovered flash steam can be utilized in any of the potential areas such as De-aerator, starch preparation, etc., Rest of the condensate is transported to utility areas through the Monobloc pumps, compressed air at 5 kg/cm^2 or motive steam at 4 kg/cm^2 and 142^{o}C. It is necessary to ensure the condensate recovery should be above 65% to reduce the make-up water consumption and associated chemical treatment costs.

Based on the production and steam consumption data, specific energy consumption should be derived and comparative analysis to be carried out with benchmark standards.

Thermic Fluid

Thermic fluid heaters were introduced to industrial applications as an alternative source of thermal energy instead of electric and steam heating. Thermic fluid heaters are available in single and multi-pass with variety of fuels firing such as coal, biomass, HSD, furnace oil and natural gas, LPG, etc as input energy. Thermic fluid is mainly used for the indirect heating application with sensible heat transfer through the jacket or radiators coils to increase the temperature of process equipment such as dyeing, stenter, etc and returns back to heater.

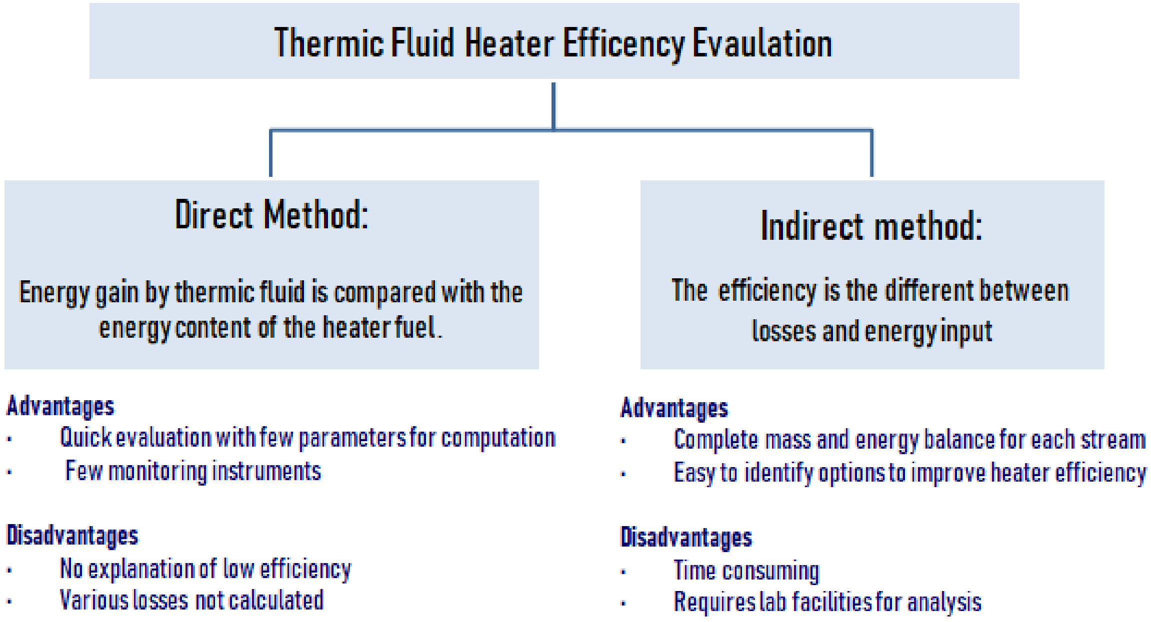
Pumps are integrated for forced circulation of heat transfer fluid in a closed loop through heater and dissipation of heat for process user ends of wet processing such as yarn drying, dyeing of fabric, stenter and high temperature machines, etc. Flow control or optimization are either carried out using variable speed drives and pneumatically operated valves as per heat load and temperature required in the user ends. Other auxiliaries include draught fans for combustion depending on the fuel fired and design of heater.

There are many heat transfer medium such as Marlotherm, Therminol and Dowtherm, etc which are selected based on the temperature required for the process. Some of the major advantages or benefits of thermic fluid compared to other heat transfer medium are listed below.

- Provide very high temperature heat without attaining the high pressure (i.e., near atmospheric pressure) as compared to steam.
- Operation in closed circuit avoids typical problems such as leaks, corrosion, water treatment, etc.
- Better thermal efficiencies without heat losses due to blowdown, flash steam and condensate drain.
- Automation control system with rapid start-up and shut downtime leading to lower level of heat losses
- Higher operational flexibility and lower maintenance cost.

Performance evaluation

Performance evaluation testing of thermic fluid heater can be carried out by the following methods as indicated in the figure:



Thermic Fluid Heater Efficency Evaulation

Direct Method:

Energy gain by thermic fluid is compared with the energy content of the heater fuel.

Advantages
- Quick evaluation with few parameters for computation
- Few monitoring instruments

Disadvantages
- No explanation of low efficiency
- Various losses not calculated

Indirect method:

The efficiency is the different between losses and energy input

Advantages
- Complete mass and energy balance for each stream
- Easy to identify options to improve heater efficiency

Disadvantages
- Time consuming
- Requires lab facilities for analysis

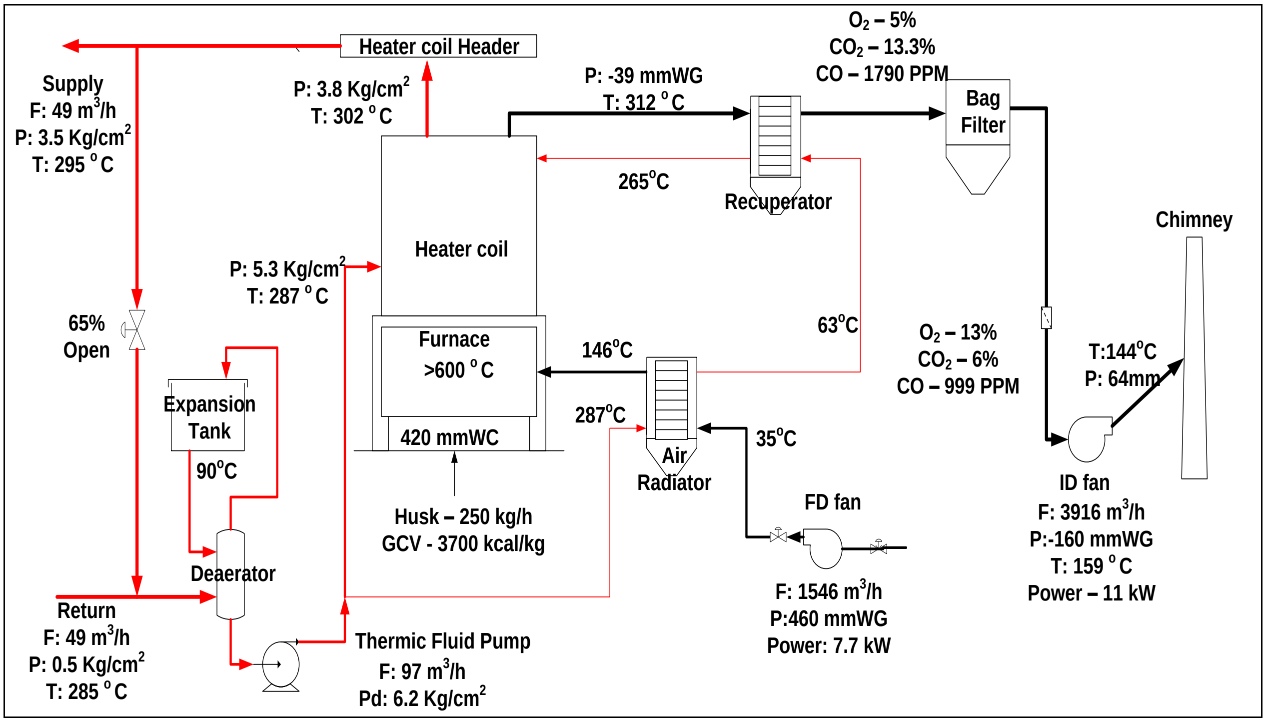
Formula used in direct efficiency method evaluation for thermic fluid heater is given below.

$$\text{Thermic fluid heater efficiency } (\eta) = \frac{\text{Heat Input}}{\text{Heat Output}} \times 100 = \frac{M_h \times C_p \times (T_i - T_o)}{Q_c \times GCV} \times 100$$

Parameters to be monitored:

- Mass flowrate of thermic fluid circulated (**M_h**) in kg/h
- Specific heat of thermic fluid (**C_p**) in kcal/kg °C)
- Inlet temperature (**T_i**) of thermic fluid across heater in (°C)
- Outlet temperature (**T_o**) of thermic fluid across heater in (°C)
- Quantity of fuel used per hour (**Q_c**) in kg/h
- Type of fuel and gross calorific value of the fuel (**GCV**) in kcal/kg of fuel

Methodology for Indirect Efficiency of thermic fluid heater is as similar to boiler system. It is very essential to monitor the major operating parameters as similar to boiler operation for performance evaluation or key performance indicators of thermic fluid heater. Schematic representation of thermic fluid heater with monitored and measured operating parameters are given in figure 3.12.



Based on the data indicted in the above figure, mass and energy balance of thermic fluid heater can be carried out using the direct efficiency methodology. Details of the same are given in table 3.10.

Table 3.10: Energy balance of thermic fluid heater

Particulars	Unit	Values
Heat gained by thermic fluid (Marlotherm)		
Circulation quantity of thermic fluid	m^3/ h	97
Density of Marlotherm @ 300°C	*Kg* / m^3	860
Mass flow rate of thermic fluid	*Kg / h*	83420
Specific heat of Marlotherm @ 300°C	*kCal / kg °C*	0.56
Inlet temperature of thermic fluid to heater	*°C*	283
Outlet temperature of thermic fluid from heater	*°C*	295
Temperature difference (gain) across heater	*°C*	12
Heat carried by thermic fluid	*kCal / h*	560582
Heat input by Husk fuel combustion in heater		
Husk fired in thermic fluid heater	*Kg / h*	250
Gross calorific value of husk (as dried basis)	*kCal /kg*	3765
Heat input from husk combustion	*Kg / h*	941250
Thermic fluid heater efficiency (as dried basis)	*%*	79.4
Actual heat utilized in thermic fluid heater	*kCal / h*	747353
Heat utilized by thermic fluid from husk combustion	*%*	75

Heat utilization by thermic fluid from husk combustion is considered satisfactory. However, there is further scope for energy efficiency exists as explained in the below example.

Revamp modification: ***Install new air preheater in the flue gas path before bag filter and remove the existing air radiator & recuperator***

In the above case study, thermic fluid heater is designed with two heat recovery devices as described below.

- Forced draft fan supplies the ambient air (35°C) for combustion of fuel, via integrated air radiator coils, where partial flow of return thermic fluid from plant (287°C) is circulated across to preheat the combustion air upto 145°C.
- Further the thermic fluid from air radiator coil passes through installed recuperator, where it exchanges heat with exhaust flue gas (312°C) from thermic fluid heater. Inlet and outlet temperature of thermic fluid across recuperator is 65°C and 260°C.

Though temperature gain across the preheated air is 110°C but thermic fluid temperature drop is more than 25°C. Heat gained details of combustion air is given in table 3.11.

Table 3.11: Heat gain details of thermic fluid heater

Particulars	Unit	Values
Circulation quantity of combustion air	m^3/ h	1546
Density of air @ 35°C	Kg / m^3	1.12
Mass flow rate of combustion air	Kg / h	1732
Specific heat of air @ 35°C	kCal / kg °C	0.234
Inlet temperature of combustion air to radiator	°C	35
Outlet temperature of combustion air from radiator	°C	145
Temperature difference (gain) across heater	°C	110
Heat carried by combustion air	**kCal / h**	**44569**

Estimated heat utilization is 5% of husk fired combustion heat release at 80% efficiency. Recommendation: It is suggested to install new air preheater in the flue gas path before bag filter and remove the existing air radiator & recuperator from the line. Though the discharge temperature of flue gas near the ID fan is 160°C but in actual scenario it is much higher. This is because air ingression & addition of compressed air diluted the flue gas and decreased its temperature. Implementation of this measure will enhance the heat recovery & avoid additional pressure drop of thermic fluid pump.

Energy Savings

Present fuel consumption in thermic fluid heater	: 250 kg/h
Present heat utilization by combustion air	: 44569
Estimated reduction in fuel due to revamp modification *(Gross calorific value considered – 3750 kcal/kg)*	: 11.88 kg/h
Annual operating hours (24 h x 335 days)	: 8040
Annual husk fuel savings	: 95.5 MT
Annual cost savings *(@ PKR 3000 / MT of Husk)*	: PKR 0.28 Million

Investment *(for revamp modification)* : PKR 0.57 Million
Simple payback period : 2.0 years

Compressed Air

In textile industry, compressed air is mainly required for the instrumentation and service applications. Pneumatic operations of instruments and machinery such as blow room, carding, sliver lap, ribbon lap, drawing, speed frame, ring frames and auto-coner, etc. Particularly in air-jet looms of weaving, compressed air demand is significant.

To cater the load of compressed air, plant management normally install screw, centrifugal and reciprocating type of compressors. Number of compressors installation for the network depends on configuration of centralized system with ring main provision or exclusive for the particular section. Operation pattern of compressors are typically defined by the user end demand and pressure required as per Original Equipment Manufacturer (OEM) specification.

Majority of the compressed air systems operation are set for “Load” and “Unload” pattern, unless variable speed drive installed for capacity control. As mentioned earlier in the book 3 – performance evaluation of compressed air system can be carried out by measuring free air delivery and power consumption to derive the specific power consumption.

Comparative analysis of both centralized and exclusive compressed air system performance for one of typical industry is given in the below table 3.12.

Table 3.12: Comparative analysis of centralised and dedicated compressed air system for typical textile plant

Description	**Free Air Delivered, CFM**		**Pressure, kg/cm^2**		**Power consumption, kW**		**Specific Energy Consumption, kW/CFM**	
	Design	*Operating*	*Design*	*Operating*	*Design*	*Operating*	*Design*	*Operating*
Spinning Mill #1, 2, 3 & 4 Centralized air compressor system								
Compressor #2	203	138	7.5	9	37	30.4	0.182	0.22
Compressor #3	608	459	10	9	110	98.1	0.181	0.214
Compressor #4	608	412	10	9	110	89.8	0.181	0.218
Compressor #9	731	709	10	9	132	147	0.181	0.207
Compressor #10	731	674	10	9	132	131.1	0.181	0.195
Compressor #11	731	595	10	9	132	133.7	0.181	0.225
Compressor #7	155	126	10.5	6	37	30.2	0.239	0.24
Fabric Division air compressor system								
Compressor #1	646	501	10	8.3	132	119.5	0.204	0.239
Compressor #2	646	437	10	8.3	132	128	0.204	0.293
Dyeing air compressor System								
Compressor #1	342	115	7	7	55	33.2	0.161	0.248
Mill #7 Air compressor System								
Compressor #2	173	161	10	8	37	35	0.214	0.217
Compressor #3	407	407	10	9	75	86.7	0.184	0.213
Compressor #5	661	596.2	10	9	125	122	0.189	0.205

From the above table, most of the compressors individual performance is on the lower side compared to design data. Overall, centralized system's specific power consumption is found to be better than exclusive compressor network. However, the same cannot be concluded as truly ideal for all the compressed air system in any other industry.

Compressed air is used for both process and instrumentation purpose. Near the user end pressure reducing valves are mostly in use to meet process equipment requirement. The monitored compressed air pressure near use end is given in below table 3.13.

Table 3.13: Monitored compressed air parameters of typical textile plant

Sl. No	**Particulars**	**Required Pressure**	**Operating Pressure, *Kg/cm²***			
		Kg/cm²	**Mill #1, #2, #3 & #4 centralized system**	**Fabric Division**	**Dyeing System**	**Mill # 5 System**
	Generation pressure, *Kg/cm²*	**7**	**8 to 9**	**7.6 to 8.3**	**7**	**8 to 9**
1	Autoconer	**6.0 – 6.5**	5.5 – 6.5	-	-	6.0 – 7.5
2	Spinning	**6.0 – 6.5**	6 – 7.5	-	-	6.5 – 8.0
3	Preparatory – Carding	**4**	2.5 – 4.5	-	-	3.0 – 4.5
4	Preparatory – Comber	**2**	1.5 – 3.0	-	-	1.5 – 3.0
5	Preparatory – Drawing M/c	**4**	3.5 – 4.5	-	-	3.0 – 4.5
6	Preparatory – Inter roving M/c	**2.5**	2.5 – 4.5	-	-	2.5 – 4.0
7	Blow room	**5**	5.0 – 8.0	-	-	5.0 – 6.5
8	Air jet looms	**6.0 – 6.5**	-	6.7 – 7.4		NA
9	TFO doubling	**5.0 – 6.0**	5.0 – 6.0	5.0 – 6.0	NA	5.0 – 6.0
10	Dyeing plant	**5.0 – 6.5**		-	5.0 – 6.5	NA
11	Boiler bag filter	**5**		5.0 – 6.0	NA	NA

Compressed air pressure and flow specification is as per defined by OEM. It is very essential to install section wise energy and flow meters for monitoring the specific air consumption and further energy optimization measures.

Humidification Systems

Textile plants will have multiple numbers of humidification units in different areas / section for maintaining the relative humidity and temperature, which will enhance productivity with many benefits such as product weight, yarn quality, static control, weaving efficiency, employee comfort.

Humidification systems comprise of spray air washers (multiple banks of heat exchanger fills with collection tank, headers, nozzles, etc.,) and auxiliary equipment such as circulation water pumps and fans (supply air and return air). Automated humidity controllers are installed to maintain the required conditions by controlling the re-circulation rate of return air as well as operation of spray pumps. Schematic representation of humidification system operations are given in figure 3.13.

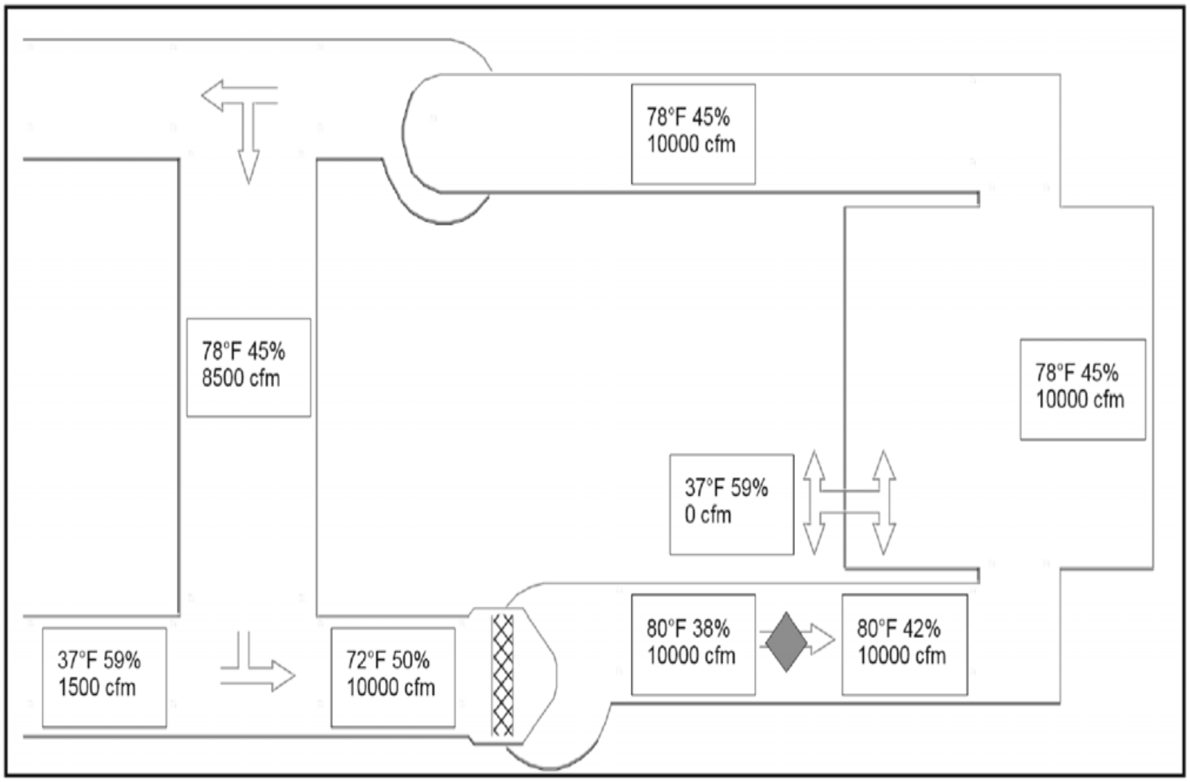


Figure 3.13: Typical humidification system operation

Some industries also installed with either vapour absorption chiller or vapour compression chiller for meeting the additional cooling load by indirect heat exchange of circulation water from air washer. Due to space constraint for installing ducted air-washer humidification system, nowadays jet spray system are considered as retrofit option, which offers following advantages.

- *Accurate humidity control* (+/-2 %) *directly to a room's atmosphere using a combination of compressed air and water. A series of strategically located nozzles provide consistent humidity throughout the space*
- *The use of compressed air ensures very rapid moisture evaporation, without the risk of wetting or drips, and highly directional spray aerosols*
- *Self-cleaning nozzles enable the humidifier to work with any potable water quality without the need for a demineralized supply*
- *Its fan-free design ensures robust operation in dirty, dusty industrial environments with minimal maintenance*

Standard humidity and temperature parameter required in plant is given section wise in below table 3.14.

Table 3.14: Standard humidity and temperature parameter required in typical textile plant

Sl. No	Section	Relative humidity	Tolerance in RH (%)	Temperature in ^{o}C	Tolerance in Temp.
1	Blow Room	50	± 15	32	± 8
2	Carding	50	± 10	32	± 5
3	Combing	50	± 10	32	± 5
4	Ring frame	55	± 10	32	± 10
5	Autoconer	60	± 10	32	± 5
6	T.F.O	65	± 10	32	± 8
7	Open end spinning	55	± 10	32	± 5
8	Packing	70	± 15	32	± 5
9	QAD	60	± 5	27	± 5

The supply and return air fans will be on continuous operation with capacity control by dampers or variable speed drive for return air, fresh air and exhaust air arrangement and these dampers position will vary continuously depending on the inside and outside climatic conditions. Air washer /spray pumps will be operating based on the required humidity in the user ends. These are the major energy intensive equipment in humidification system. Hence automation option based on thermostatic feedback with variable speed drives is also considered as energy efficiency measures.

Energy Efficiency Assessment in Humidification Systems

Supply air (SA) and return air (RA) fans: Fan efficiency was evaluated based on operating parameters of flow rate, suction pressure, delivery pressure and actual power consumption as per methodology in Book 3 – Fans and blowers. Examples of performance evaluation for few humidification fans in textile industry are given below in table 3.15.

Table 3.15: Evaluated efficiency of supply and return air fans in humidification systems

Fan Description	Air flow rate, m^3/h		Total Pressure, mm WC		Power, kW		Operating Efficiency %	Remarks
	Design	*Operating*	*Design*	*Operating*	*Design*	*Operating*		
Preparatory								
RA fan-1	***75997***	72911	***96***	*58.5*	**30**	*22.6*	**56**	Satisfactory
SA fan-1	***107280***	76752	***58***	*36*	**30**	*14.2*	**59**	Satisfactory
Spinning								
RA fan-1	***196650***	83542	***48***	*58*	**37**	*24*	**60**	Satisfactory
SA fan-1	***196650***	87617	***48***	*47*	**37**	*26*	**47**	Low
Winding block								
RA fan-1	***98325***	42638	***72***	*54*	**30**	*12.8*	**54**	Satisfactory
SA fan-1	***103680***	59640	***65***		**30**	*13.7*	**53**	Satisfactory

Spray / air washer pumps: Pump efficiency was evaluated based on operating parameters of flow rate, suction head, discharge head and actual power consumption as per methodology in Book 3 – Pumps and cooling tower chapter. Examples of performance evaluation for few air washer pumps of typical textile industry are given in table 3.16.

Table 3.16 Evaluated efficiency of spray / air washer pumps in humidification systems

Pump Description	Flow rate, m³/h		Head developed, m		Power, kW		Efficiency	Remarks
	Design	*Operating*	*Design*	*Operating*	*Design*	*Operating*	%	
Spinning -1 *(VFD @ 50 Hz)*	***180***	130	***32***	36	***22***	21.5	***66***	Good
Preparatory plant *(VFD @ 25 to 50 Hz)*	***150***	75 to 142	***36***	9 to 38	***22***	3 to 22	***68***	Good
Blow room *(VFD @ 33 Hz)*	***180***	102	***28***	14	***22***	7	***62***	Good
Cone packing	***50***	40	***30***	24	***7.5***	5.8	***53***	Satisfactory
OES -1	***65***	16	***29***	30	***7.5***	5.7	***28***	Poor
NSE Carding	***62***	44	***20***	17	***7.5***	6.6	***36***	Poor
Dyeing	***78***	101	***42***	21	***15***	11	***64***	Good
Winding	***110***	92.5	***32***	22	***15***	12	***53***	Satisfactory

Increasing the saturation efficiency of air washer system will lead to energy savings of fans by reduced supply air demand due to improved temperature profile. Saturation efficiency can be estimated using the following formula.

$$\textbf{Saturation Efficiency (\%)} = \frac{\text{Inlet air Dry Bulb Temperature, °C} - \text{Exit air Dry Bulb Temperature, °C}}{\text{Inlet air Dry Bulb Temperature, °C} - \text{Inlet air Wet Bulb Temperature, °C}} \times 100$$

Sensible heat load: For section / department wise heat load estimation, multiple parameters such as energy consumption of operating equipment / machines, human body occupancy, transmitted heat gains from lighting, solar radiation and infiltration along with supply air, etc is required. Refer ASHRAE - HVAC guidelines book for detailed explanation and better understanding of heat load, ventilation and air conditioning calculation.

Based on these measured parameters, sample estimation of cooling load for few department in typical textile industry is given in table 3.17.

Table 3.17 Estimated TR generation and specific power consumption of humidification systems

Particulars	Supply air flow	Inlet air conditions (Return)		Inlet air enthalpy	Outlet air conditions (Supply)		Outlet air enthalpy	Cooling load
	m³/h	*dbt, °C*	*RH, %*	*kcal/kg*	*dbt, °C*	*RH, %*	*kcal/kg*	*Kcal/h*
Preparatory plant	***215798***	34.6	55.5	21.1	24	91	17.0	949536
Spinning-1	***99792***	36	47.5	21.4	24	100	18.2	347760
Winding	***53413***	28	83.9	21.1	26	100	20.3	42336
Cone packing	***44366***	29	83	20.7	25	100	19.2	72576
Open end spinning	***54714***	29.8	74.63	20.5	25	100	19.2	72576
NSE carding	***119599***	28.5	76.7	19.8	24.5	99	18.6	160272
Fabric Division	***86984***	31	74	21.4	24.3	100	18.5	272160
Dyeing-2	***32136***	31	76	21.8	25.5	100	19.8	69552

Taking the advantage of ambient conditions, humidification plant fans should be operated. Re-circulation of air percentage and supply air flow should be changed according to outside dry bulb temperature (°C) and relative humidity (RH%). The re-circulation percentages for optimum parameters to maintain are given below in table 3.18.

Table 3.18: Recirculation percentage of supply air for optimum operation

Ambient conditions	DBT	RH	Re-circulation air
	°C	%	%
Winter without rain	low	low	75
Winter with rain	low	high	100
Summer without rain	High	low	0
Summer with rain	High	high	50

In case of spinning mills, the difference in airflow rate requirements for two seasons (winter and summer) is about 15 to 20%. Plant can decide to reduce the speed or switching off supply and return fans during favourable weather conditions.

Water

Water is another essential utility for textile industry. Plants would have provision for bulk supply of raw water, which is subjected for treatment as per standards. Treated water is mainly used in make-up water for cooling towers, boilers and humidification system apart from the process water demand in wet processing. There is no such high energy intensive but smaller capacity pumps whose performance can be monitored periodically.

Effluent treatment plant

Effluent treatment plant is an integral part of textile industry particularly with the wet processing systems. Waste water from various streams consists of effluents and sometimes energy of high temperature operations (dyeing, desizing, washing, mercerization, soaper hot water bath), which is dreadfully lost during the treatment before water is safely disposed or utilized in the afforestation or mills sanitary systems. Hence heat recovery options from waste water to incoming fresh water in hot water machine applications can be explored with integration of plate heat exchanger.

Lighting

Textile plant is illuminated with various kinds of lamps and luminaries such as Fluorescent tube lights, Mercury vapour lamps and LED lamps in different areas. Since lighting use in the process areas is continuously “ON” it is necessary to ensure energy efficient appliances are in place. Translucent sheets installation particularly in raw material yard and good shed areas, wherever if feasible and periodical cleaning of the same to save energy by utilizing the natural day light.

3.7 Case studies/numerical examples

3.7.1 200 kg of fabric is to be dyed in a jigger. The dye liquor is heated from 30 to 80°C. Calculate the quantity of steam required at 2kg/cm2 (g) and specific steam consumption if the liquor ratio is 1:6.

Using the heat balance equation,
Heat energy input = Heat energy output
i.e., Ms x Enthalpy of steam = $(M_l \times Cp_l \times \Delta t_l)$ + [10% of (heat taken by the liquor)]
Enthalpy of steam at 2kg/cm^2 (g) = 650kcal/kg

Given liquor ratio =1:6, which implies to dye 200kg of fabric,1200 litres of water is required

Quantity of steam (Ms) $= \frac{[1200 \times 1 \times (80-30) + (0.1 \times [1200 \times 1 \times (80-30))]}{650}$
= 101.54 kg
Specific steam consumption = 0.51kg steam/ kg cloth

3.7.2 The throughput of a textile stenter is 1200kg/hr. The inlet moisture content of the cloth is 50% and the outlet moisture is 5%. The inlet and outlet temperature of cloth is 28°C and 80°C. The stenter is supplied with steam at an enthalpy of 660 kcal/kg, the condensate leaves at 90°C. The flow rate of steam is 1000 kg/hr. Estimate the overall thermal efficiency of the dryer. The latent heat of evaporation of water is 540kcal/kg.

1200kg/hr of wet cloth contains
1200 x 50% kg of water = 600 kg/hr of moisture
And 1200x (100%-50%) = 600 kg/hr bone dry cloth

As the final product contains 5% moisture, the moisture in the product is (600*0.05)/0.95 = 31.57kg
Inlet moisture =600/600 = 1kg of moisture/kg of bone dry material
Outlet moisture =31.57/600 = 0.053kg of moisture/kg of bone dry material

Dryer efficiency, %= $\frac{Material\ Flow \times (Moist.input - Moist.output) \times [(Temp.out - Temp.in) + 540\}}{Thermal\ energy\ Input}$

Dryer efficiency, % $= \frac{600 \times (1 - 0.053) \times [(80-28) + 540\}}{1000 \times (660-90)}$ x 100
Dryer Efficiency = 59.01%

3.7.3 Calculate the SEC (kWh/kg) in a ring spinning machine; where the linear density of yarn is 20, diameter of the ring is 0.04m; speed of the spindle is 17500 r.p.m. ; and the twist factor of the yarn is 3828.

Using the Ring spinning machine SEC equation

$$SEC = 106.7 \times F^{-1.482} \times Dr^{3.343} \times (n/1000)^{0.917} \times \alpha_{text}^{0.993}$$

Where F: Linear density of yarn =20 tex.
Dr: diameter of the ring = 0.04m
n: Speed of the spindle = 17500rpm
α: twisting factor of yarn = 3828.

$$SEC = 106.7 \times 20^{-1.482} \times 0.04^{3.343} \times 17.500^{0.917} \times 3828^{0.993}$$

$$SEC = 1.33 kWh/kg$$

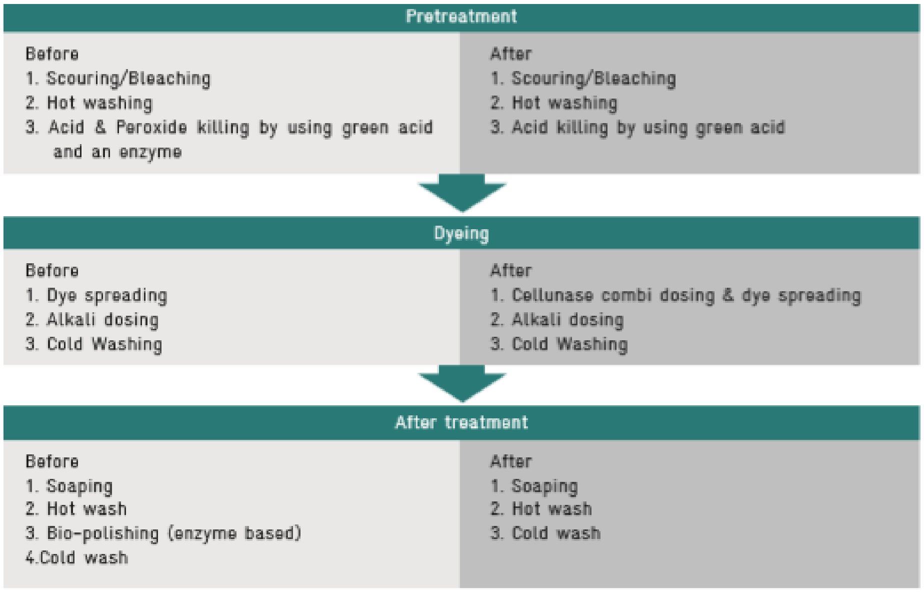
3.7.4 Elimination of 2 bath by combining bio-polish and Dyeing

In a textile industry a project has been implemented in the towel manufacturing section with an objective to further reduce the energy consumption and save water in the dyeing section of towel manufacturing.

Detailed assessment of the dyeing section by the plant team revealed an opportunity for elimination of two bath process by combining Bio wash with Dyeing Process in Combi process. Plant decided to take trial of the proposed scheme. The plant team took this target as an excellent opportunity to further enhance their overall process performance.

Trials were undertaken to combine the bio-wash and dyeing process to eliminate the bio-polishing stage in after treatment. For this a need for a new enzyme was felt which would perform the dual function of peroxide killing and bio-polishing. The challenge was discussed with the enzyme vendor, who subsequently engineered an enzyme to solve the dual purpose.

After series of discussions, permission for trails was obtained and trials were conducted for modification in the process with the ultimate objective of maintaining the product quality. The process, before and after the implementation of the scheme, is depicted in the following diagram.



Pretreatment	
Before	After
1. Scouring/Bleaching 2. Hot washing 3. Acid & Peroxide killing by using green acid and an enzyme	1. Scouring/Bleaching 2. Hot washing 3. Acid killing by using green acid

Dyeing	
Before	After
1. Dye spreading 2. Alkali dosing 3. Cold Washing	1. Cellunase combi dosing & dye spreading 2. Alkali dosing 3. Cold Washing

After treatment	
Before	After
1. Soaping 2. Hot wash 3. Bio-polishing (enzyme based) 4.Cold wash	1. Soaping 2. Hot wash 3. Cold wash

Figure 3.14: Pre- treatment, Dyeing & After-treatment before and after elimination of bio polishing in after treatment stage

As depicted in Figure 3.14, the enzyme dosing in pre-treatment step for peroxide killing has been eliminated followed by cellulase combi enzyme dosing in dyeing stage before the dye spreading. This results in elimination of bio-polishing in the after-treatment stage.

The enzyme performs dual action of peroxide killing and bio polishing in dyeing stage itself. The enzyme has been engineered specifically for serving this dual purpose by the vendor. Also, the introduction of this enzyme has led to the elimination of peroxide killing enzyme which was used earlier in the pre-treatment stage.

The plant team continuously checked the quality of the product during the trials and found that there was no impact of this modification on the product quality. This modification has additionally led to tangible savings in terms of steam saving by elimination of bio-polishing and water saving as well.

Benefits

Energy Savings in kWh = 10,000 kWh
TOE equivalent savings = 142.4 TOE
Investment = Minimal
Payback (Months) = Immediate

3.8 Energy efficiency improvement Measures in Textile Industry

This section of energy-efficiency improvement measures in the textile industry includes both opportunities for retrofit/process optimization as well as the complete replacement of the current machinery with state-of-the-art new technology. However, special attention is paid to retrofit measures since state-of-the-art new technologies have high upfront capital costs, and therefore the energy savings which result from the replacement of current equipment with new equipment alone in many cases may not justify the cost.

However, if all the benefits received from the installation of the new technologies, such as water savings, material saving, less waste, less waste water, less redoing, higher product quality, etc. are taken into account, the new technologies are more justifiable economically. It should be noted that the energy saving and cost data provided in this chapter are either typical saving/cost or plant/case-specific data.

The savings from and cost of the measures can vary depending on various factors such as plant and process-specific factors, the type of fiber, yarn, or fabric, the quality of raw materials, the specifications of the final product as well as raw materials (e.g. fineness of fibre or yarn, width or specific weight of fabric g/m2, etc), the plant's geographical location, etc. For instance, for some of the energy-efficiency measures, a significant portion of the cost is the labour cost. Thus, the cost of these measures in the developed and developing countries may vary significantly.

Sl No:	Energy Efficiency Technologies & Measures in Textile Industry
	Preparatory process
1	Installation of electronic Roving end-break stop-motion detector instead of pneumatic system
2	High-speed carding machine
	Ring Frame
3	Use of energy-efficient spindle oil
4	Optimum oil level in the spindle bolsters
5	Replacement of lighter spindle in place of conventional spindle in Ring frame
6	Synthetic sandwich tapes for Ring frames
7	Optimization of Ring diameter with respect to yarn count in ring frames
8	False ceiling in Ring spinning section
9	Installation of energy-efficient motor in Ring frame
10	Installation of energy-efficient excel fans in place of conventional aluminum fans in the suction of Ring Frame
11	The use of light weight bobbins in Ring frame
12	High-speed Ring spinning frame
13	Installation of a soft starter on motor drive of Ring frame
	Windings, Doubling, and finishing process
14	Installation of Variable Frequency Drive on Autoconer mchine
15	Intermittent mode of movement of empty bobbin conveyor in the Autoconer/cone winding machines
16	Modified outer pot in Tow-For-One (TFO) machines
17	Optimization of balloon setting in Two-For-One (TFO) machines
18	Replacing the Electrical heating system with steam heating system for the yarn polishing machine
	Air conditioning and Humidification system
19	Replacement of nozzles with energy-efficient mist nozzles in yarn conditioning room
20	Installation of Variable Frequency Drive (VFD) for washer pump motor in Humidification plant
21	Replacement of the existing Aluminium alloy fan impellers with high efficiency F.R.P (Fiberglass Reinforced Plastic) impellers in humidification fans and cooling tower fans
22	Installation of VFD on Humidification system fan motors for the flow control
23	Installation of VFD on Humidification system pumps
24	Energy-efficient control system for humidification system
	General measures for Spinning plants
25	Energy conservation measures in Overhead Travelling Cleaner (OHTC)
26	Energy-efficient blower fans for Overhead Travelling Cleaner (OHTC)
27	Improving the Power Factor of the plant (Reduction of reactive power)
28	Replacement of Ordinary 'V – Belts' by Cogged 'V – Belts'
	Energy-efficiency technologies and measures in the weaving process

29	Evaluation and enhancement of the energy efficiency of compressed air system in the Air-jet weaving plant
	Wet- Processing
30	Combine Preparatory Treatments in wet processing
31	Cold-Pad-Batch pretreatment
32	Bleach bath recovery system **
33	Use of Counter-flow Current for washing
34	Installing Covers on Nips and Tanks in continuous washing machine
35	Installing automatic valves in continuous washing machine
36	Installing heat recovery equipment in continuous washing machine
37	Reduce live steam pressure in continuous washing machine
38	Introducing Point-of-Use water heating in continuous washing machine
39	Interlocking the running of exhaust hood fans with water tray movement in the yarn mercerizing machine
40	Energy saving in cooling blower motor by interlocking it with fabric gas singeing machine's main motor
41	Energy saving in shearing machine's blower motor by interlocking it with the main motor
42	Enzymatic removal of residual hydrogen peroxide after bleach Enzymatic scouring
43	Use of integrated dirt removal/grease recovery loops in wool scouring plant
	Dyeing and Printing Process
44	Installation of Variable Frequency Drive on pump motor of Top dyeing machines
45	Heat Insulation of high temperature/ high pressure dyeing machines
46	Automated preparation and dispensing of chemicals in dyeing plants
47	Automated dyestuff preparation in fabric printing plants
48	Automatic dye machine controllers
49	Cooling water recovery in batch dyeing machines (Jet, Beam, Package, Hank, Jig and Winches)
50	Cold-Pad-Batch dyeing system
51	Discontinuous dyeing with airflow dyeing machine
52	Installation of VFD on circulation pumps and color tank stirrers
53	Equipment optimization in winch beck dyeing machine
54	Equipment optimization in jet dyeing machines
55	Single-rope flow dyeing machines
56	Microwave dyeing equipment
57	Reducing the process temperature in wet batch pressure-dyeing machines
58	Use of steam coil instead of direct steam heating in batch dyeing machines (Winch and Jigger)
59	Reducing the process time in wet batch pressure-dyeing machines
60	Installation of covers or hoods in atmospheric wet batch machines
61	Careful control of temperature in atmospheric wet batch machines
62	Jiggers with a variable liquor ratio
63	Heat recovery of hot waste water in Autoclave

64	Insulation of un-insulated surface of Autoclave
65	Reducing the need for re-processing in dyeing
66	Recover heat from hot rinse water
67	Reuse of washing and rinsing water
68	Reduce rinse water temperature
	Drying Process
69	Energy-efficiency improvement in Cylinder dryer
70	Introduce Mechanical Pre-drying
71	Selection of Hybrid Systems
72	Recover Condensate and Flash Steam
73	End Panel Insulation
74	Select Processes for their Low Water Add-on Characteristics
75	Avoid Intermediate Drying
76	Avoid Overdrying
77	Reduce Idling Times and Use Multiple Fabric Drying
78	Operate Cylinders at Higher Steam Pressures
79	Maintenance of the dryer
80	The use of radio frequency dryer for drying acrylic yarn
81	The use of Low Pressure Microwave drying machine for bobbin drying instead of dry-steam heater
82	High-frequency reduced-pressure dryer for bobbin drying after dyeing process
	General energy-efficiency measures for wet-processing
83	Automatic steam control valves in Desizing, Dyeing, and finishing
84	The recovery of condensate in wet processing plants
85	Heat recovery from the air compressors for use in drying woven nylon nets
86	Utilization of heat exchanger for heat recovery from wet- processes wastewater
	Finishing Process
87	Conversion of Thermic Fluid heating system to Direct Gas Firing system in Stenters and dryers
88	Introduce Mechanical De-watering or Contact Drying Before Stenter
89	Avoid Overdrying
90	Close Exhaust Streams during Idling
91	Drying at Higher Temperatures
92	Close and Seal Side Panels
93	Proper Insulation
94	Optimize Exhaust Humidity
95	Install Heat Recovery Equipment
96	Efficient burner technology in Direct Gas Fired systems
97	The Use of Sensors and Control Systems in Stenter

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Chapter 4 Energy Performance Assessment of Pulp and Paper Industries

4.1 Introduction

Pulp and paper is a key industry in the world and paper is an important material, used daily for many purposes worldwide. Papermaking is thought to have originated in China in about 100 A.D. using rags, hemp and grasses as the raw material, and beating against stone mortars as the original fibre separation process. Although mechanization increased over the intervening years, batch production methods and agricultural fibre sources remained in use until the 1800s.

The global production of paper and cardboard stood at approximately 419.7 million metric tons in 2017. More than half of that production was attributable to packaging paper, while almost one third was attributable to graphic paper. North America, Asia, and Europe account for most of the world's paper and pulp. The world's three largest paper producing countries are China, the United States, and Japan. These three countries account for more than half of the world's total paper production.

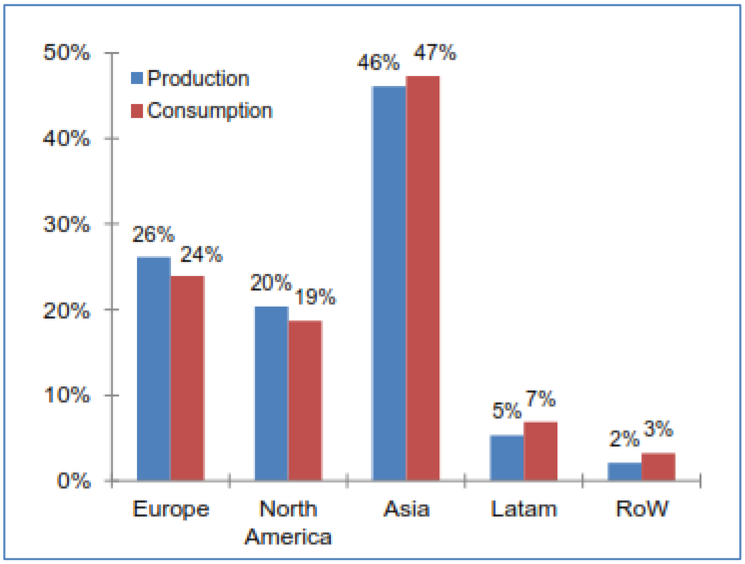

Figure 4.1: Region wise paper and paper board production 2017

With some 423.3 million metric tons of paper consumed globally in 2017, the world's paper consumption is roughly equal to the amount of paper produced annually. China is the world's largest paper and paperboard consumer, using more than 113 million metric tons annually, followed by the U.S. with a consumption rate of nearly 71 million metric tons.

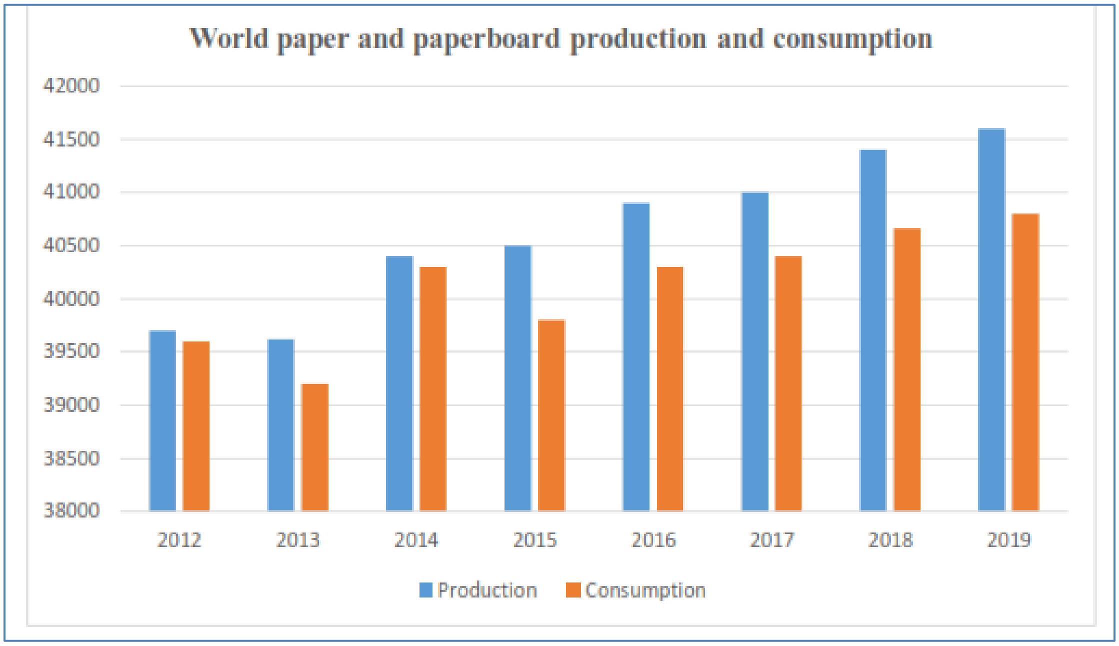

Figure 4.2: World Paper and Paperboard Production and Consumption

Pakistan Industrial Development Corporation (PIDC) established the first paper mill in East Pakistan (Now Bangladesh) during 1953, followed by a high grade paper mills -Adamjee Paper & Board Mills at Noshera in NWFP and a Newsprint Mill at Khulna in East Pakistan (Bangladesh) in 1959.

At present, in Pakistan there are about 100 units in the organized and unorganized sectors. These units produce Writing and Printing Paper, Wrapping and Packing Paper, White duplex coated, Un-coated board, chip Board and other board. More than 70 % of mills are located in Punjab province, 20 % in Sindh and 10% in Khyber Pakhunkhwa province.

Paper consumption in Pakistan is in far excess of the domestic capacity. Over a period of time, domestic industry has attained capacities and capabilities to produce all major Paper & Paperboard products leaving small room for imports. However, domestic demand of some specialized papers, including coated art paper / card and newsprint, is met through imports.

4.2 Paper Manufacturing Process

Paper production is basically a two-step process in which a fibrous raw material is first converted into pulp, and then the pulp is converted into paper. The paper manufacturing process has several stages - Raw material preparation and handling, Pulp manufacturing, washing and screening, Chemical recovery, Bleaching, Stock Preparation, and Papermaking.

Figure 4.3 illustrates the major pulp and paper making processes such as mechanical pulping, chemical pulping, re-pulping waste paper, papermaking and converting. Pulp is generally manufactured in large mills in the same regions as the fibre harvest (i.e., mainly forest regions). Most of these mills also manufacture paper - for example, newsprint, writing, printing or tissue papers; or they may manufacture paperboards.

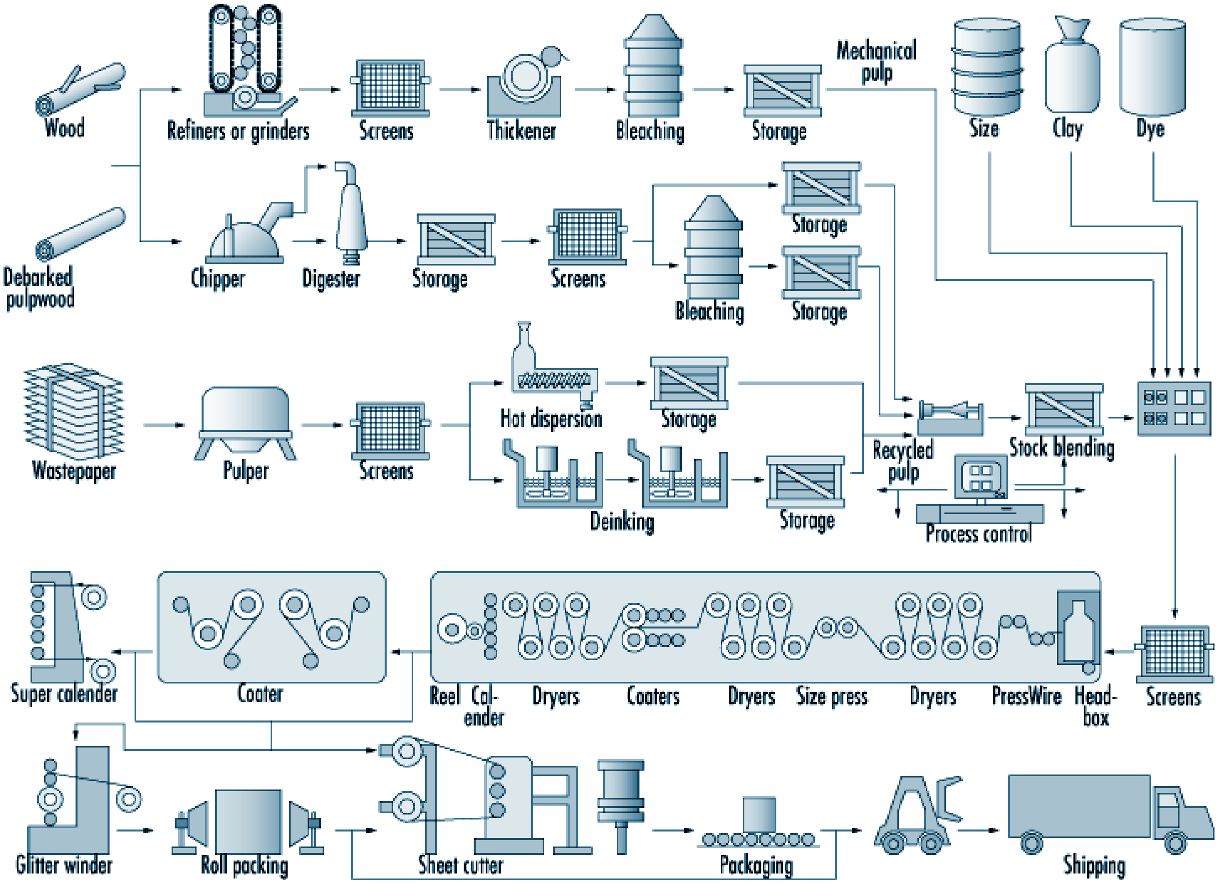

Figure 4.3: Illustration of process flow in pulp and paper manufacturing operations

4.3 Pulp Manufacturing

Wood and recycled wastepaper are the main raw materials for paper pulp fibre, the former accounting for 43% and the latter accounting for the remaining 57%. Recently, the use of wastepaper accounts for more than half of the fibre raw materials from the viewpoint of energy and resource saving. The paper industry contributes to society as a recycling-oriented industry through the use of wastepaper and the promotion of afforestation projects. Simple flow diagram of pulp and paper making process is given in figure 4.4.

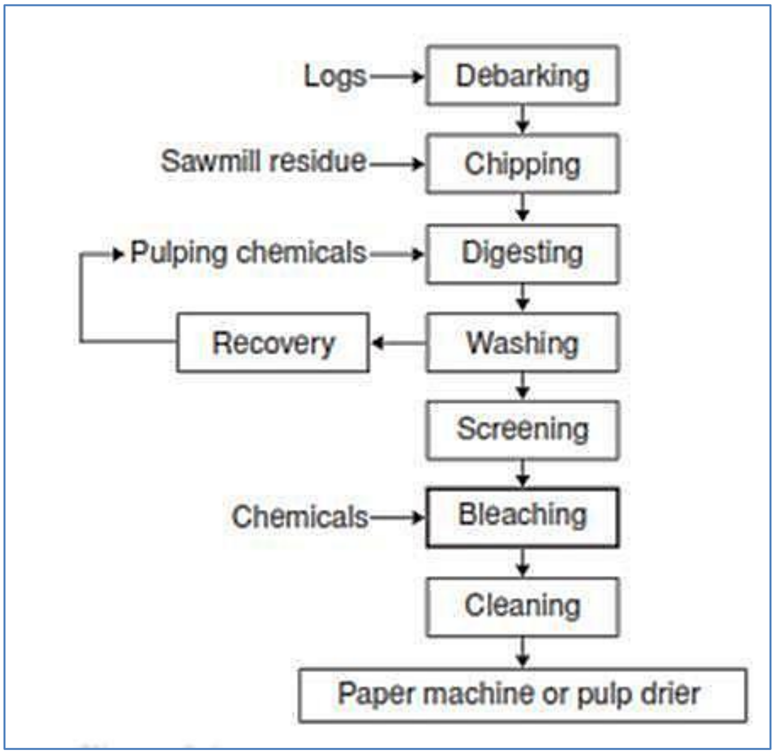

Figure 4.4: Pulp and papermaking process

Pulp manufacturing methods from wood are roughly classified into a) mechanical pulp manufacturing methods in which physical force is applied to wood to mill it and b) chemical pulp manufacturing methods in which extract fibres with chemical agents. The former includes ground-wood pulp, refiner ground wood pulp, thermo-mechanical pulp methods and others. The later includes sulfite pulp and kraft pulp methods.

Table 4.1: Types of Pulping

Process	Pulp color	Yield (%)	Uses
Thermo-mechanical pulping	Brown	>95	Boxboard, newsprint, paper bags
Chemi-thermo mechanical pulping	Light brown	85–95	Newsprint, specialty papers
Semi-chemical	Beige–brown	60–80	Newsprint, bags
Chemical-–kraft, sulphite	Light brown	40–55	Newsprint, fine papers

Use of wastepaper is roughly classified into gray stock to be used for baseboards for corrugated fibre board and paperboard for paper boxes, and DIP (deinked pulp) from deinked and bleached wastepaper for use as printing paper and computer paper.

The process of preparation and papermaking by appropriately mixing such pulp is used to produce paper of various qualities and features.

4.3.1 Paper Manufacturing from Recycled Waste paper

The various processes involved in paper manufacturing from recycled waste paper are listed below:

1) De-inking
2) Stock preparation
3) Wet end process
4) Dry end process

The process flow diagram is given in figure 4.5.

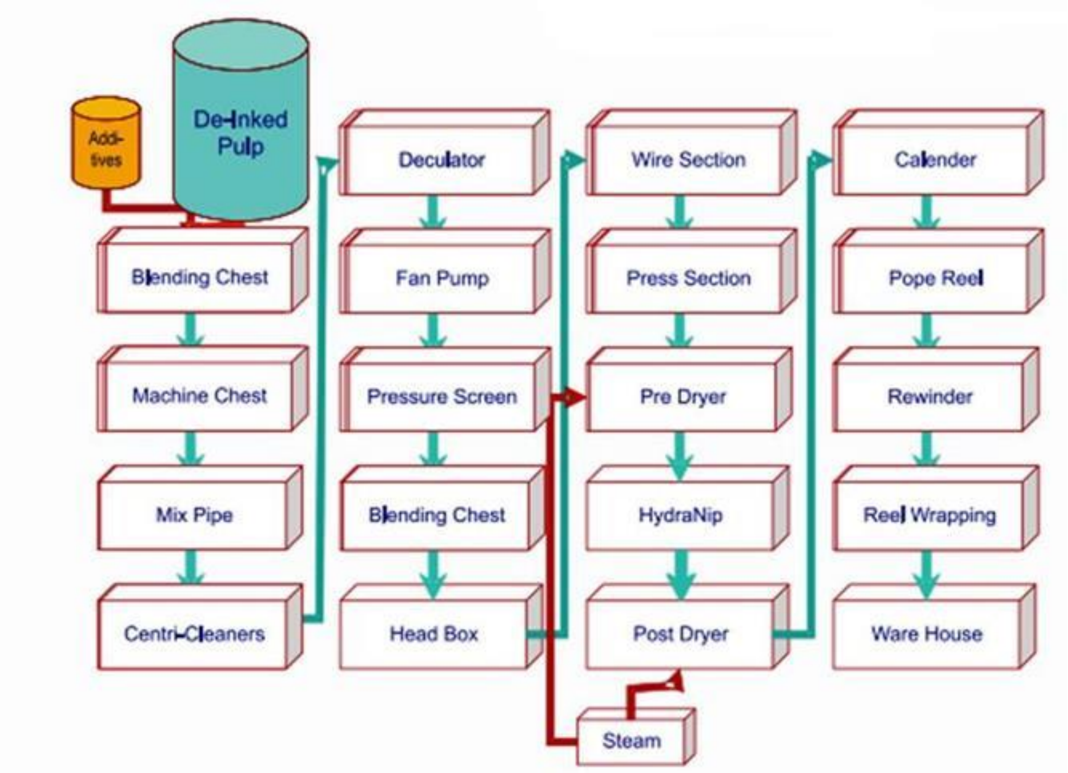

Figure 4.5: Process Flow Diagram of papermaking from Wastepaper

De-inking Process / Secondary Fibre Treatment

The recovered paper feedstock is blended with water in a large tank. Pulping chemicals are added to the process to aid in the production of fibrous slurry. Large contaminants and contaminants that float are removed from the slurry. Inks and other fibre contaminants are removed using chemical surfactants. The combined application of heat, dissolution of chemical bonds and mechanical shear action liberates fibres and produces a pulp with desired properties and consistency.

Stock Preparation

The purpose of stock preparation is to process the pulp into homogenous slurry with properties suitable for introduction into the paper machine. Stock preparation involves the following processes: mechanical homogenization of pulp, dispersion in water, fibre de-clustering, adding wet additives, blending and contaminant screening. The purpose of wet additives is to provide the final paper product with specific desirable properties (such as color and water repellence) and to improve the quality and efficiency of the paper making process. The pulp slurry is then fed to the head box.

Wet end Process

The slurry first enters a head box, which creates a uniform layer of slurry and deposits this layer onto a moving fabric (also called wire or forming fabric). This fabric forms the fibres into a continuous web while allowing water removal via gravity and the application of vacuum pressure.

Once the fibres have been sufficiently dewatered and begin to bond to form paper, they move on to the press section where paper is pressed to remove water, which promotes further bonding between fibres. The paper is supported by rolls and press fabrics which absorb water from the sheet at the press nips. The bonded and dewatered sheet then proceeds to dry end of the paper machine for further drying and finishing operations.

Dry end Process

Dry end processes include drying, calendering, and reeling. In the drying section, steam heated rollers compress and further dry the sheet through evaporation, which facilitates additional bonding of fibres. In the middle of this section is the size press, which can apply coating to the paper and then dried after coating. The next step is calendering, which involves a series of carefully spaced rollers that control the thickness and smoothness of the final paper. After calendering, the finished paper is wound on a large reel for storage and transportation.

4.3.2 Paper Manufacturing from Wood

The various processes involved in manufacturing paper from wood pulp are listed below.

1) Cooking
2) Chemical recovery
3) Washing and Screening
4) Bleaching
5) Stock Preparation
6) Paper making
7) Finishing and Sizing

The process flow diagram is given in figure 4.6.

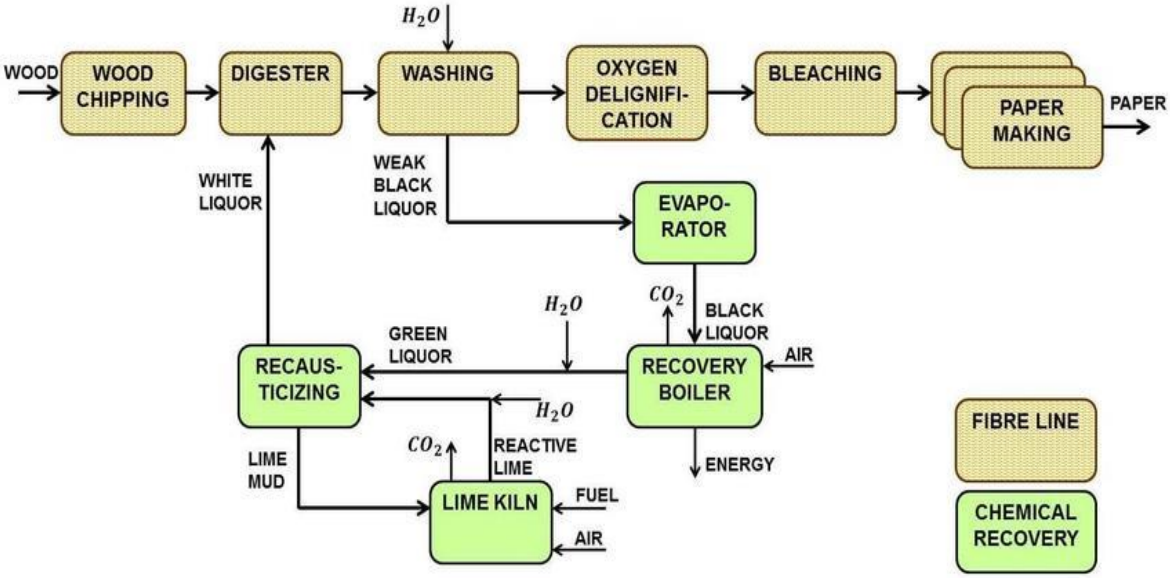

Figure 4.6: Process Flow Diagram of papermaking from Wood

4.3.3 Chemical pulp manufacturing process (kraft pulp processing)

Kraft pulp processing produces strong pulp and is highly adaptable to different types of wood. Also, chemicals used for pulping can be recovered and recycled. Other constituents of wood such as lignin are converted into heat energy using boilers in the chemical recovery process. Wood chips are cooked with caustic soda to produce brown stock, which is then washed with water to remove cooking (black) liquor for the recovery of chemicals and energy.

Three generations of modified kraft pulping processes (modified continuous cooking, isothermal cooking, and compact cooking as examples for continuous cooking and cold blow, Super Batch/rapid displacement heating, and continuous batch cooking for batch cooking technology) have emerged through continuous research and development. The third generation includes black liquor impregnation, partial liquor exchange, increased and profiled hydroxide ion concentration, and low cooking temperature (elements of compact cooking); also the controlled adjustment of all relevant cooking conditions in that all process-related liquors are prepared outside the digester in the tank (as realized in continuous batch cooking). However, the potential of kraft cooking is not exhausted by far.

Many of the developments in kraft pulp production have been driven by severe environmental concerns. Increasing pulp production resulted in increasing effluent loads. The industry is now advancing to the stage of adopting the Elemental Chlorine Free (ECF) method to further reduce environmental load. Section wise process description is provided in below section. Figure 4.7 shows a simplified schematic diagram of the kraft pulping process and the corresponding chemical and energy recovery process.

(1) Cooking process

Woodchips and chemical (white liquor: NaOH + Na2S) are placed in a digester, cooked at a high temperature and pressure (about 160-170°C and 10 ata), and separated into cellulose fibres and lignin, etc. The cellulose fibres are continuously washed in warm water and sent to the bleaching process after uncooked materials are removed with a screen. To be used as kraft paper for corrugated cardboard, pulp after screening and washing is direct sent for manufacturing of paper without bleaching.

In batch cooking, the digester is filled with chips, white cooking liquor and weak black liquor. The cooking liquor, which is drawn through screens, is circulated with a pump to a heat exchanger, where the liquor is heated with steam before being returned to the digester. The chips are cooked for about three hours in this caustic atmosphere. This cooking action dissolves the bond between the cellulose fibres and the glue-like material called lignin that cements the fibres together.

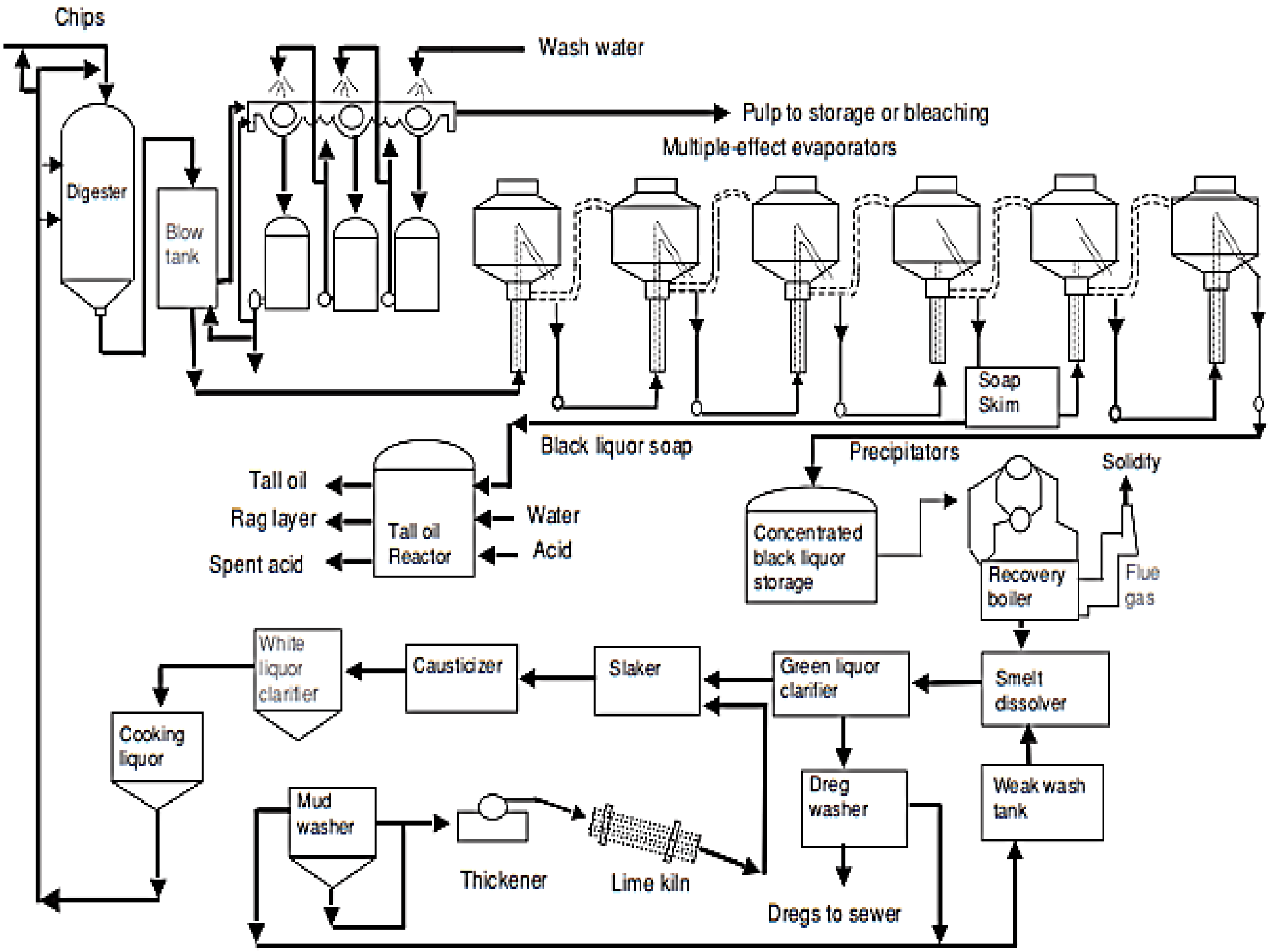

Figure 4.7: Kraft Pulping Process with Chemical and Energy Recovery Cycle

After cooking, the pulp is blown through a blow valve into a blow tank where the shock of the material hitting the tank wall separates the lignin and fibres. There is also an enhanced cooking batch digester, where the liquor goes through heat exchangers to help cook the chips without using all the steam in a standard batch digester, which means more energy efficiency and economy.

Continuous digesters use a heated, pressurized chamber into which chips and chemicals are fed. Chips are processed in a downward flow through zones of steadily increasing temperatures and pressure until the cooking zone is reached. The cooking liquor is also continually circulated from the digester to heat exchangers, where the liquor is reheated and re-injected into the digester. The pH of the cooking liquors is 13.5 to 14 and the operating temperatures are 240° F (116° C) at 140 psi. Schematic of continuous digester is given in figure 4.8.

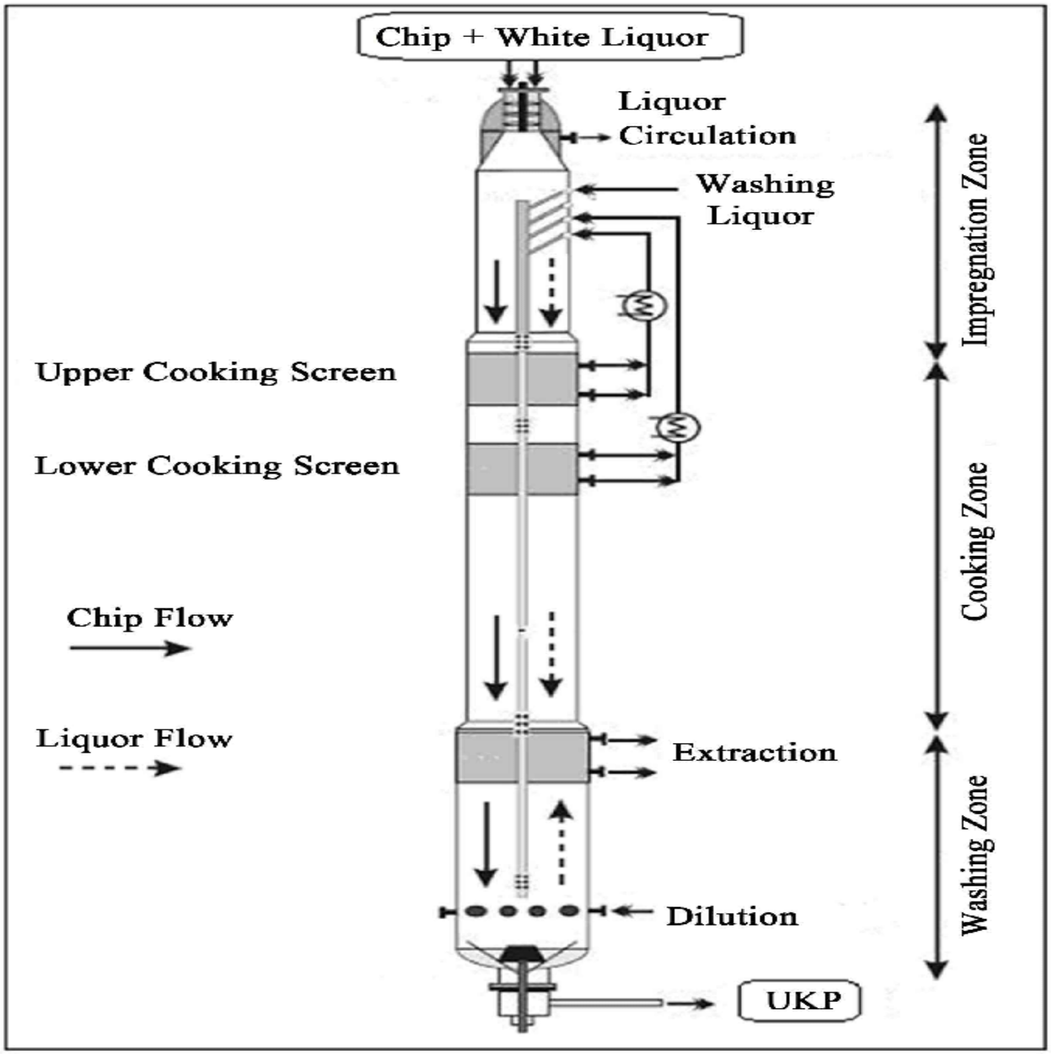

Figure 4.8: Continuous Digester

A high-pressure feeder (the heart of the digester) sends the chips to the digester inlet. A rotating helical screw pushes down chips, and steam and liquor are used to cook the chips—impregnation, heating, cooking and washing of the chips is done in one continuous operation. The chips remain in this area from two to three hours and the mass is cooled, mixed with black liquor, and mechanically conveyed or "blown" to the blow tank.

4.3.4 Chemical recovery process

The recovery process is achieved through a well-defined series of steps, starting with the weak black liquor coming from the brown stock washers. The process steps are then:

- Concentration of liquor in multiple evaporators and concentrators to get to heavy black liquor
- Addition of salt cake to make up for soda loss
- Incineration of heavy black liquor in the recovery boiler
- Dissolving smelt from the boiler to form green liquor (new liquor)
- Burning of lime mud to recover lime
- Causticizing of green liquor with lime to form white liquor.

Lumber ingredients (lignin and hemicellulose excluding fibres), which are separated at the cooking process, and the remaining liquid chemicals are sent to the chemical recovery process. The chemical compound (black liquor) is concentrated from 14%~ 15% concentrations to 62% concentration in multiple effect evaporators.

The heavy black liquor is then fired in a recovery boiler to generate steam and power. Smelt obtained from the recovery boiler is dissolved in water to get green liquor. Green liquor passes through settling tanks and sent to lime slacker where lime is added to obtain white liquor. White liquor so obtained is passed through causticizer and sent back to digester house for pulping process.

The recovery area is where chemicals from the spent cooking liquors are recovered. The reconstitution of these chemicals can form fresh cooking liquor at the same time incinerating organic residuals creates energy.

Multiple Effect Evaporators

After the blow tank, the stock is washed in a brown stock washer. The fibres are then transferred to the stock prep area, and the wash is recovered and sent to the evaporators. Evaporators take the water out of the liquor to create high-density black liquor to burn in the recovery boiler. The evaporator island may include as many as six evaporators which are called effects—for example, the vapor in one effect becomes the steam supply in the next unit. There are four types of evaporators: rising film, falling film, cascade and cyclone.

Recovery Boiler

Heavy black liquor is pumped to a black liquor storage tank at the recovery boiler where the liquor is mixed with salt cake—sodium sulphate—as a make-up chemical to replace the chemicals lost during washing and evaporation. The black liquor is then pumped by the nozzle pump into the boiler, where the liquor is vaporized and burned, the organics in the liquor burn as fuel, while the chemicals fall to the bottom of the boiler and flow out as smelt. The smelt flows into a dissolving tank filled with weak wash liquor from the causticizing area. The smelt is agitated and recycled to break up the molten smelt and prevent an explosion. The liquor in the dissolving tank is called green liquor.

Causticizing

Green liquor from the dissolving tank is pumped to the causticizing area where it is treated with milk of lime, calcium hydroxide, to form white liquor. Because green liquor contains impurities called dregs, it must be filtered in a clarifier. The clarified green liquor is then pumped to the slaker where it is mixed with burnt lime, calcium oxide. The lime-green liquor mixture flows to two or three causticizers in a series to complete the reaction. The liquor is separated from the lime mud and becomes white liquor. The calcium carbonate precipitate is burned in the lime kiln to form calcium oxide for use in the causticizing area.

4.3.5 Pulp Washing

After pulp production, pulp processing removes impurities, such as uncooked chips, and recycles any residual cooking liquor via the pulp washing process. The most common washing technology is rotary vacuum washing, carried out sequentially in two, three, or four washing units. Other washing technologies include diffusion washers, rotary pressure washers, horizontal belt filters, wash presses, and dilution/extraction washers. Pulp screening removes remaining oversized particles such as bark fragments, oversized chips, and uncooked chips.

In open screen rooms, wastewater from the screening process goes to wastewater treatment prior to discharge. In closed-loop screen rooms, wastewater from the process is reused in other pulping operations and ultimately enters the mill’s chemical recovery system. Centrifugal cleaning (also known as liquid cyclone, hydrocyclone, or centri-cleaning) is used after screening to remove relatively dense contaminants such as sand and dirt. Rejects from the screening process are either repulped or disposed of as solid waste.

4.3.6 Screening

Screening of the pulp is done to remove oversized and unwanted particles from good papermaking fibres so that the screened pulp is more suitable for the paper or board product in which it will be used. The biggest oversized particles in pulp are knots defined as uncooked wood particles. The knots are removed before washing and fine screening. In low-yield pulps they are broken down in refiners and/or fibreizers; The main purpose of fine screening is to remove Debris chop, i.e. shives, chop, and any other material that would have any sort of bad effect on the papermaking process or on the properties of the paper produced not separated by chemical pulping or mechanical action.

4.3.7 Bleaching

Bleaching of pulp is done to achieve a number of objectives. The most important of these is to increase the brightness of the pulp so that it can be used in paper products such as printing grades and tissue papers. Bleaching also eliminates the problem of yellowing of paper in light. Resin and other extractives present in unbleached chemical pulps are also removed during bleaching, and this improves the absorbency, which is an important property for tissue paper grades. An oxygen bleaching process is adopted to remove lignin prior to the chlorine bleaching process to reduce the environmental load in the subsequent process that uses chlorinated chemicals.

4.3.8 Stock Preparation

Stock preparation is conducted to convert raw stock into finished stock (furnish) for the paper machine. The pulp is prepared for the paper machine including the blending of different pulps, dilution, and the addition of chemicals. The raw stocks used are the various types of chemical pulp, mechanical pulp, and recovered paper and their mixtures. The quality of the finished stock essentially determines the properties of the paper produced.

Stock preparation consists of several process steps that are adapted to one another as fibre disintegration, cleaning, fibre modification, and storage and mixing. These systems differ depending on the raw stock used and quality of furnish required.

The following operations are practiced in the paper mills.

- Dispersion
- Refining
- Metering and blending of fibre and additive

Dispersion

Pulpers are used to disperse dry pulp into water to form a slush or a slurry. The stock in the pulper is accelerated and decelerated repeatedly, and hydrodynamic shear forces are produced by the severe velocity gradients. The resulting forces serve to loosen fibres and reduce any flakes into individual fibres.

Refining

Refining develops the bonding ability of the fibres without reducing their individual strength by damaging them too much, while minimizing the development of drainage resistance. In refining, pulp is passed continuously through one or more refiners, whether in series or in parallel.

Figure 4.9: Refiner in Stock Preparation Unit

Two types of continuous refiner are used for stock preparation: conical refiners and disk refiners. Conical and disk refiners have almost completely replaced beaters in stock preparation systems. They occupy less space at similar levels of production and are more efficient in developing fibre strength.

4.3.9 Paper machine

The actual papermaking process consists of two primary processes: dry-end and wet-end operations. In wet-end operations, the cleaned and bleached pulp is formed into wet paper sheets. In the dry-end operations, those wet sheets are dried and various surface treatments are applied to the paper.

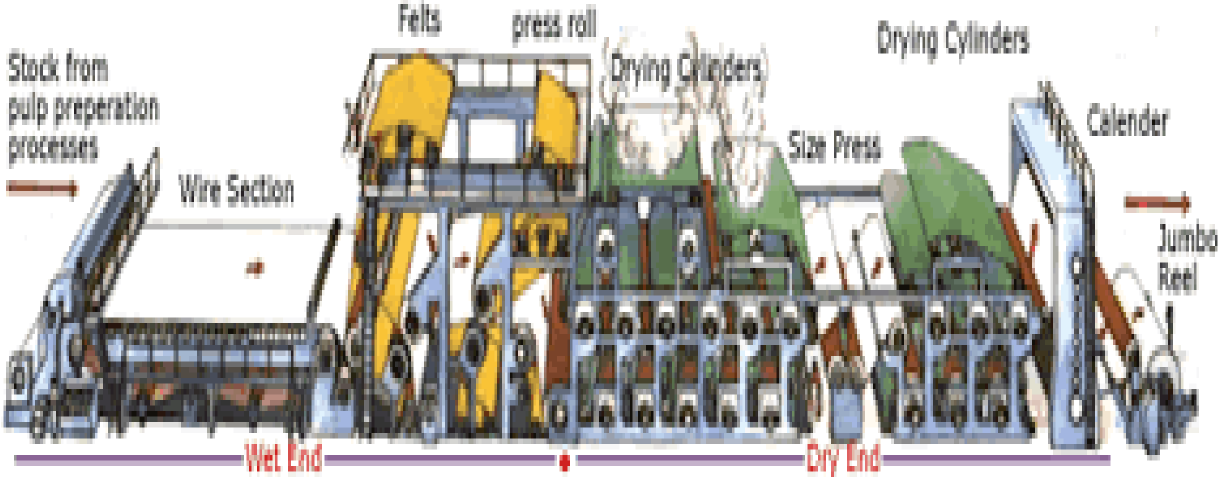

Figure 4.10: Paper Making Section

Paper machine comprises of wet and dry end. Pulp at around 1% concentration is passed through wire part where water is removed by gravity flow. After gravity flow, water is removed by pressing, followed by vacuum based water removal and finally by evaporation using indirect steam heating. The final product of >96% dryness is then trimmed at the both ends, rolled and cut to desired length for despatch.

The traditional Fourdrinier machine is still widely used but for many paper grades has been replaced with twin-wire machines or gap formers and hybrid formers. The pulp flowing onto the forming wire is approximately 0.5–1.0% fibres, with the makeup consisting of water. As the water is removed from the slurry, the fibres settle onto the surface of a traveling wire, forming a wet mat of paper. Therefore, the main objective of the forming section is the controlled removal of water.

Foils remove water using a doctor blade at the bottom of the forming wire. The blade causes a difference in pressures, which draws water from the web behind the blade. This method allows for more control over the removal process and is not significantly affected by machine speeds.

Water removal can be further enhanced by placing a vacuum on the foil drainage system. After the foils, water is further removed using flat suction boxes. The suction boxes remove the majority of the water, changing the stock consistency from 2% to 20% fibre content.

When the paper leaves the couch roll, it contains 80–85% of water, is very easily damaged, and will support its own weight for only a very short distance. It is therefore transferred to a traveling woolen felt, which supports it through the first of a series of presses whose function is to remove more water by squeezing and at the same time make the sheet denser and smoother. Two or three presses are used in series, and the paper may go directly through, or it may pass under one press and be reversed through its rolls so that the two sides of the sheet may be more nearly alike.

After leaving the presses, the paper goes to the dry section of the machine, the purpose of which is the removal of the water, which cannot be taken out by pressing and which amounts to about 70% of the weight of the wet paper at this point. In passing the driers, about 2 lb of water must be evaporated for each pound of paper made. In cold climates, if this is allowed to escape directly into the room, it causes condensation on the ceiling and water drops all over the machine, so it is customary to cover the drier section with a hood from which the vapors are removed by fans.

4.3.10 Finishing

After the drying section, the web is subjected to several finishing steps prior to shipping it as a final product. The web can be sized, giving the paper surface resistance, or if other properties are needed, the web can be surface-coated. In the final stages, the web is rewound and slit into two or more rolls and if needed sheeted.

4.3.11 Sizing

Sizing imparts resistance to liquids on the paper surface, a property necessary for paper used for writing or printing. Size presses are located after between the two drier sections and apply a coat of sizing by transference from rollers, and the metering is accomplished by the nip.

4.4 Energy consumption pattern in pulp and paper industry

The energy consumption of pulp and paper industry (both thermal and electrical energy), varies based on the raw material used. The global benchmarking data for various raw material based paper making plants is given in table 4.2.

Table 4.2: Global Benchmarking of paper production

Mill classification	Particulars	Units	Global Avg
Wood based Mills	Sp. Electrical Energy Consumption	kWh / T of paper	1000 – 1100
	Sp. Steam consumption	T of steam/T of paper	7.0 - 9.0
Agro based Mills	Sp. Electrical Energy Consumption	kWh / T of paper	-
	Sp. Steam consumption	T of steam/T of paper	
RCF based Mills producing unbleached grades	Sp. Electrical Energy Consumption	kWh / T of paper	500
	Sp. Steam consumption	T of steam/T of paper	2.5
RCF based Mills producing bleached grades	Sp. Electrical Energy Consumption	kWh / T of paper	600 -650
	Sp. Steam consumption	T of steam/T of paper	4.0 - 4.5

Table 4.3 gives the typical section-wise energy consumption of a wood based paper mill.

Section	Power Consumption (kWh/ T of paper)	Steam Consumption (T of steam/ T of paper)
Pulp Mill	300 - 325	1.2 - 2.5
Recovery section	250 - 300	3.0 - 3.5
Stock preparation & paper machine	350 - 450	2.5 - 4.0
Effluent Treatment Plant	75 - 100	-
Power generation plant	150 - 200	-
Total	1126 - 1300	3.7 - 6.5

4.5 Performance evaluation

4.5.3 Steam consumption and steam economy

Chemical recovery is an important operation in pulp and paper industry from the economic point of view. One of the main steps in the recovery of alkaline pulping chemicals is the concentration of black liquor to higher solids content by evaporation. The multiple effect evaporator system is used for the concentration of weak black liquor.

Multiple effect evaporators (MEE) system is an energy intensive system and therefore any measure to reduce the energy consumption by reducing the steam consumption will improve steam economy and help in improving the profitability of the plant. Evaluating the operating steam economy of the MEE system plays a vital role to understand the existing system and find further scope for improvement.

Steam economy is defined as "**the quantity of water evaporated/ removed as vapour for every kilogram of live steam consumed"** and it is used to evaluate the performance of MEE system.

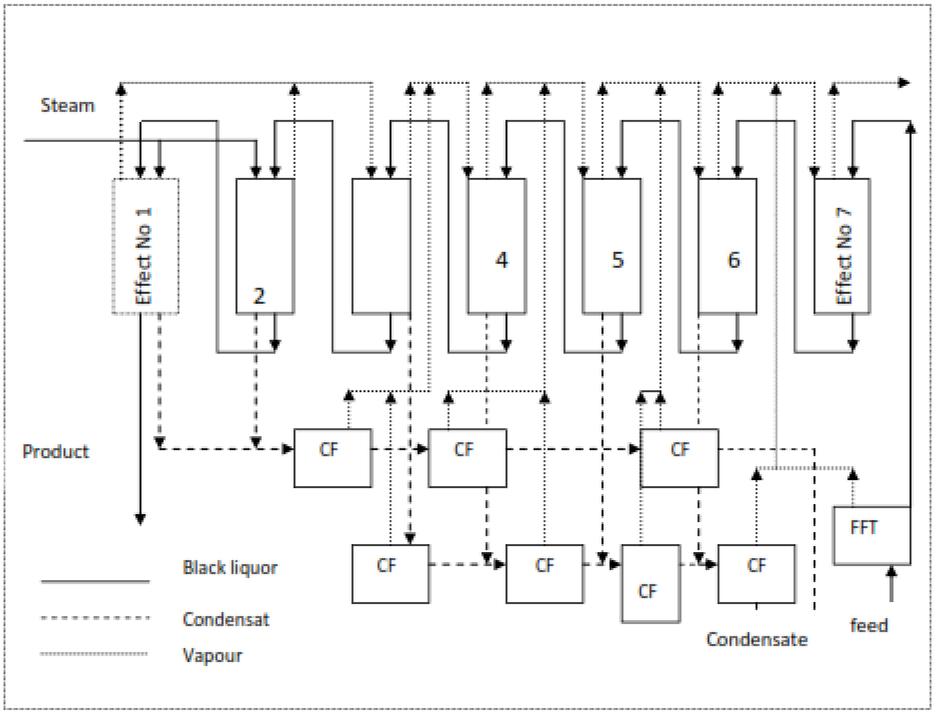

Figure 4.11: Schematic diagram of a Multiple Effect Evaporator System

Figure 4.11 represents a schematic diagram of a MEE system in a paper plant with seven effects. Live steam is supplied to first and second effect while feed is fed to the 7th effect in a counter current direction. The auxiliary vapour generated is used in subsequent effects to enhance the overall steam economy of the system.

Example 16.1: steam economy of multiple effect evaporator

In a multiple effect evaporator, 70m3/hr of black liquor having a specific gravity of 1.08 at an initial concentration of 18% is fed at 69°C and has to be concentrated to 55%. Live steam quantity of 11 TPH at 2.5 bar pressure and 140°C temperature is supplied to the evaporator. Find out the steam economy of the evaporator.

Solution:

Feed flow rate	:	70 m3/hr
Specific gravity	:	1.08
Mass flow of feed	:	70 x 1.08
	:	75.6 TPH
Inlet % solids	:	18%
Final % solids	:	55%
Mass flow rate of product	:	75.6 x 18 / 55
	:	24.74 TPH
Water evaporation	:	75.6 – 24.74
	:	50.86 TPH
Live steam consumption	:	11 TPH
Steam Economy	:	50.86 / 11
	:	4.62

4.6 Case Study

In this section some examples of the paper de-watering and steam requirements for paper drying are discussed.

Example 16.2:

A paper machine is operating at 1000m/min speed and produces newspaper at 42gsm containing 5% moisture content without break. The deckle of paper on the reel is 4.135m. The consistency of pulp feed in the head box is 0.5% and the dryness of wet paper entering the dryer section is 40% respectively. Determine a) Daily production b) Total quantity of water removed and C) Moisture evaporated in dryer section.

Solution:

Dryness of pulp, Di = 0.5%

Dryness of paper entering dryer section, Dp = 40%

Moisture in final product, M_{FP} = 5%

Paper machine speed = 1000m/min

Length of deckle = 4.135m

Paper GSM = 42gsm

a) Daily Production:

Production = speed (m/min) x GSM x deckle (m) x minutes per day/ (1000 x 1000)
= (1000 x 42 x 4.135 x (24 x 60)) / (1000 x 1000)
Daily Production = 250 Tonnes / day

b) Total Quantity of Water Removed:

Dryness of final product, Df = 100 - M_{FP} = 100 - 5= 95%
Dry content in paper per day = 0.95 x 250 = 237.5 tonnes
Moisture in final product, Mp = 250 – 237.5 = 12.5 tonnes
Let “Mf” be mass of pulp feed to head box.
Mass of pulp feed, Mf = 250 x 0.95 / 0.005 = 47,500 tonnes
Initial moisture content = Mf x (100 – Di)/100
= 47,500 x (100 – 0.5) / 100 = 47,262.5 tonnes
Mass of water removed = Mf – Mp
= 47,262.5 – 12.5 = 47250 Tonnes

c) Moisture evaporated in Dryer Section

Mass of wet paper entering dryer, Md = 250 x 0.95 / 0.4 = 593.75 tonnes
Initial moisture content = Md x (100 – Di)/100
= 593.75 x (100 – 40) / 100 = 356.25 tonnes
Mass of water evaporated = Md – Mp = 356.25 – 12.5
= 343.75 Tonnes

4.7 References

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Chapter 5 Energy Performance Assessment of Steel Re-rolling Mills

5.1 Introduction

Iron and steel is the largest consumer of energy among all industrial sectors. In a typical integrated steel plant, the coking coal is the predominant source of primary energy. It has long been an established fuel economy policy for integrated steel mills to try their best in utilizing by-product gases derived from iron and steel making while limiting the purchase of fuels and electric power from outside. Currently, there are two main routes for the production of steel.

- Primary steel
- Secondary steel

Primary Steel: Primary steel is produced by using iron ore and scraps, primary steelmaking involves converting liquid iron from a blast furnace and steel scrap into steel via basic oxygen steelmaking, or melting scrap steel or direct reduced iron (DRI) in an electric arc furnace.

Secondary Steel: Secondary steel is produced by using sponge iron and scraps, secondary steelmaking involves the refining of the crude steel using strong electric current (AC/DC) in an Electric Arc Furnace (EAF) to produce steel. In secondary metallurgy, alloying agents are added, dissolved gases in the steel are lowered, and inclusions are removed or altered chemically to ensure that high-quality steel is produced after casting. The different routes of primary and secondary steelmaking are shown in figure 5.1.

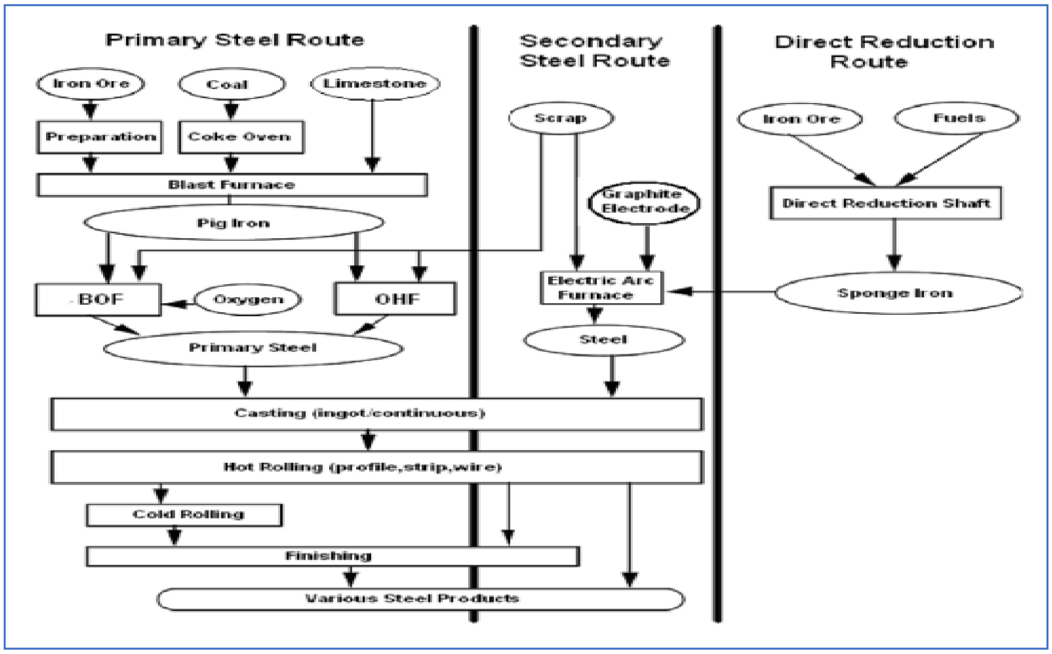


Figure 5.1 shows the different routes used for primary and secondary steelmaking

5.2 Steel Re-rolling process

Steel re-rolling mill is secondary steel making process, which involves, converting raw/unprocessed steel into finished steel products by rolling and re-rolling them in their hot state into desired shapes such as bars, TMT (thermo-mechanically treated) rods, sectional products, and wires.

Rolling is a process that is followed in most metal making activities. Material is passed through a stock of rollers in order to maintain a level shape and thickness. Generally, there are two types of rolling, i.e., hot rolling and cold rolling. No matter what type of rolling, a mills roll makes the metal crafting process easier and hassle-free.

5.2.1 Hot Rolling Steel

Hot rolling steel is processed at exceptionally high temperatures. These rolls are pressed at temperatures that are even higher than the recrystallization temperature for any steel material. The primary function of the hot rolling mill is to reheat slabs/ingots/ billets/blooms of steel in reheating furnace, close to soaking temperature point, then rolls to thinner and longer through successive rolling mill stands driven by electric motors. Typical hot rolling mill consists of a reheat furnace, sizing press, roughing mill, finishing mill, run out table and coiler, as shown in Figure 5.2.

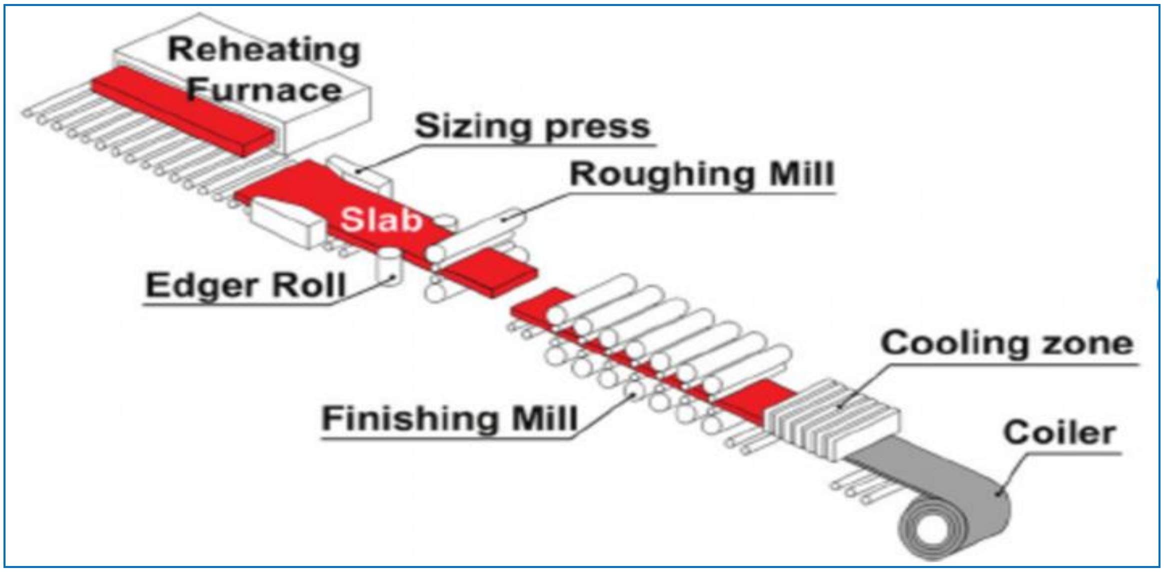


Figure 5.2 Typical hot rolling mill process

5.2.2 Cold Rolling Steel

Cold rolled steel is essentially hot rolled steel that has had further processing. The steel is processed further in cold reduction mills, where the material is cooled (at room temperature) followed by annealing and/or tempers rolling. This process will produce steel with closer dimensional tolerances and a wider range of surface finishes. Typical cold roll press is shown in figure 5.3.

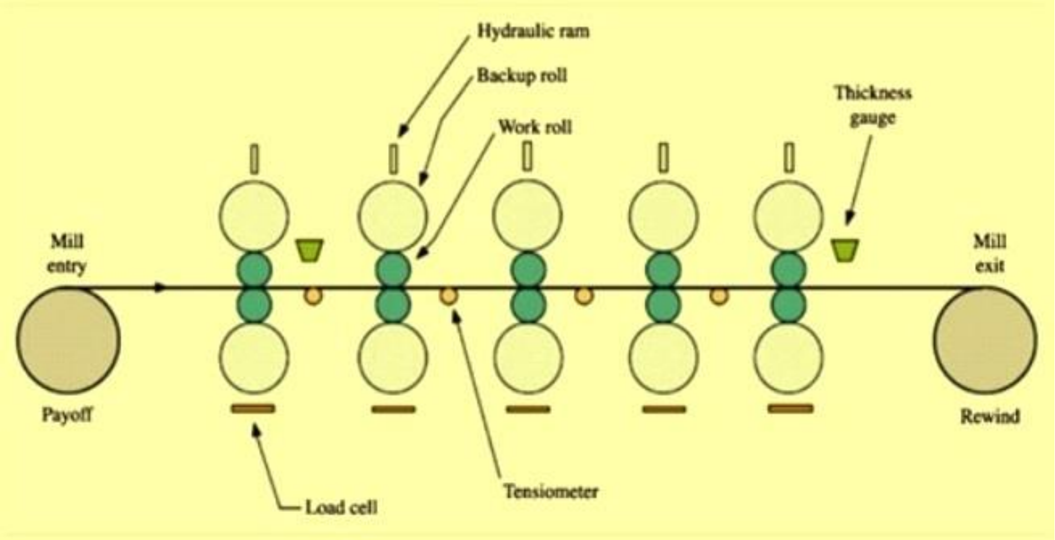


Figure 5.3 Cold rolling process

In the re-rolling mill process, the re-heating furnace is central to efficient production. The amount of energy required to fire and keep it heated has a direct bearing not only on production efficiency but also on bottom lines and more crucially on greenhouse gas (GHG) emissions.

5.3 Reheating Furnaces

Reheating Furnace is the heart of any hot rolling mill wherein the charge is heated to rolling temperature. The charge could be in the form of billets, blooms, slabs or ingots. The reheating furnace can be classified in a number of ways:

- Based on the method of heating, reheating furnaces can be combustion type or electric. The combustion furnace can be coal, oil or gas-fired.
- Based on heat recovery mechanism, reheating furnaces can be classified as regenerative or recuperative.
- Based on the method of charging, reheating furnaces can be classified as batch type or continuous type. In batch furnaces, the charged material remains in a fixed position on the hearth until heated to rolling temperature. In continuous furnaces, the charged material moves through the furnace and is heated to rolling temperature as it progresses inside.
- Continuous furnaces can be further classified based on the movement of steel stock in heating zones. Most popular continuous type of furnaces include pusher, rotary hearth, walking beam, walking hearth or roller hearth type.

Most of the steel rolling industries are equipped with continuous type heating furnaces. Different types of batch furnaces and continuous furnaces are described below.

Batch furnace

Batch type furnaces are conventional furnaces, used in steel heating in batches, also known as ‘in-and-out’ type furnace or ‘periodic furnace’. These furnaces are capable of heating all grades and sizes of steel stock. They are used to heat a large single piece used for forging operation or heat treatment purpose or small pieces weighing 3 – 50 kg for rolling operations.

In batch type reheating furnaces used for rolling purposes, the raw material is loaded manually without any pusher (mechanical) system and then heated to the required rolling temperature. These furnaces are generally 5–10 metre long and 1–2 metre wide. In batch type furnaces, the material does not move; it lies on the hearth until it is heated to the required temperature upon which it is taken out for heat treatment or rolling purpose. Some of the disadvantages of batch furnaces include the following:

- High capital investment per unit of production
- Low hearth productivity and area efficiency
- High man-hours per tonne of heated product
- Limitation of length of pieces to be heated

Continuous pusher furnace

In this type of furnaces, the charge or stock is introduced at one end (‘feeding or charging’), which moves through the furnace and is discharged at the other end (‘discharge doors’). There exists a temperature gradient in the length of the furnace. In general, the material and combustion gases move opposite to each other. On the basis of the temperature gradient, the continuous furnace is divided into three zones or segments i.e., preheating, heating and soaking zones as shown in the figure 5.4.

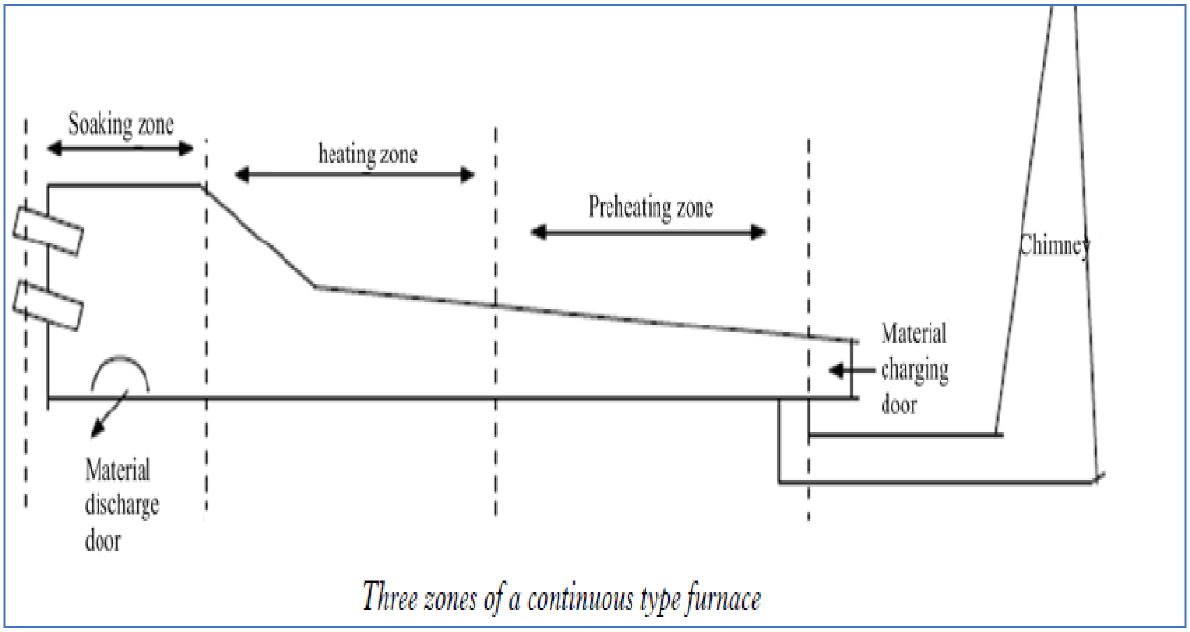


Figure 5.4 Furnace zones

Continuous furnaces are further classified according to the following:

- Number of heating zones (one, two to five, top or top-bottom) and the method of moving of material (pusher type, walking beam type, rotary hearth type or roller hearth type).
- Based on heat recovery, the reheating furnace can be either regenerative or recuperative.

The advantages of pusher type furnaces are as follows:

- High production per unit capital investments
- High hearth area efficiency and higher specific production per unit of space utilized
- Ease of charging and discharging
- A gradual rise in temperature permits charging of all grades of cold materials
- More control of the rate of heating at all temperature levels

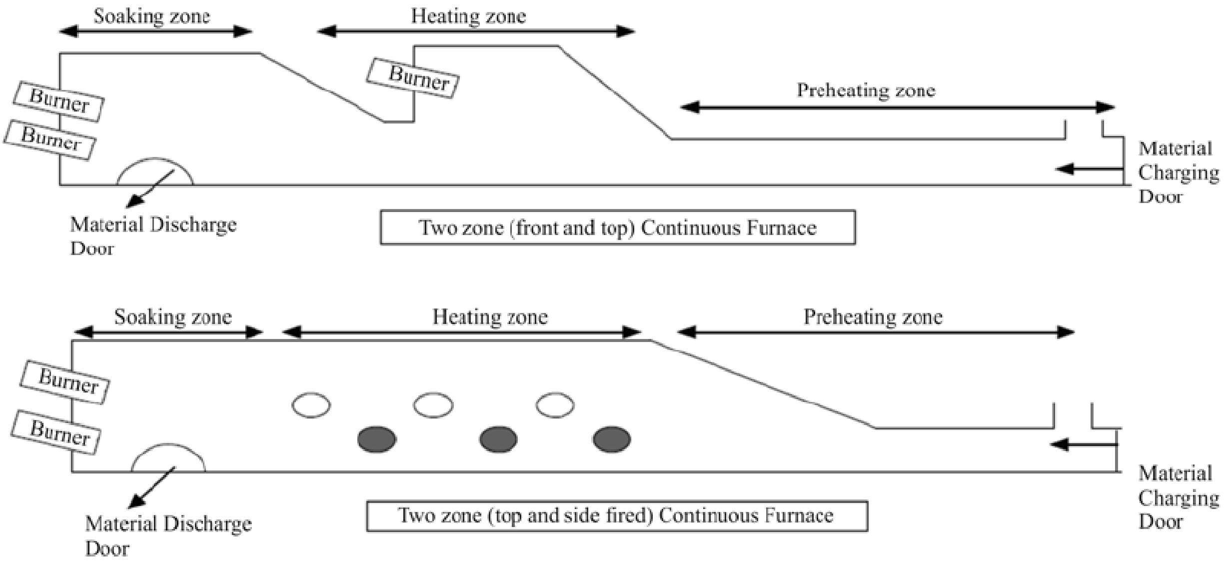
The disadvantages associated with pusher type furnaces are given below. However, these shortcomings do not limit the use of continuous furnaces over the batch type.

- Limits the cross-section of the charge since the contacting surface is to be square to avoid piling up inside the furnace
- No flexibility for heating efficiently small quantity or low thicknesses of steel stock
- It is marginally difficult to maintain water-cooled skid and also limits the thickness of steel stock to a maximum of 300-350 mm when water-cooled skids are used.

Different types of continuous steel reheating furnaces commonly used in the country as well as in other parts of the world are described below.

Pusher type furnace:

The cold steel stock is pushed forward with the help of pushers at the charging side. These furnaces are designed for heating billets/ingots or smaller sections of blooms. The hearth of pusher furnaces used earlier was short in length and sloped downward longitudinally towards the discharge end in order to permit easy passage of steel stock through the furnace. Presently, pusher furnaces are long with hearths up to 30 metre length. The steel stock is moved forward by pushing the last piece charged with a pusher at the charging end. With each pushing of the cold steel stock against the continuous line of material, a heated piece is discharged at the discharge end through an end door upon a roller table feeding the rolling mill, or pushed through a side door to the mill roller table by suitable manual or mechanical means or withdrawn through the end door by a mechanical extractor.

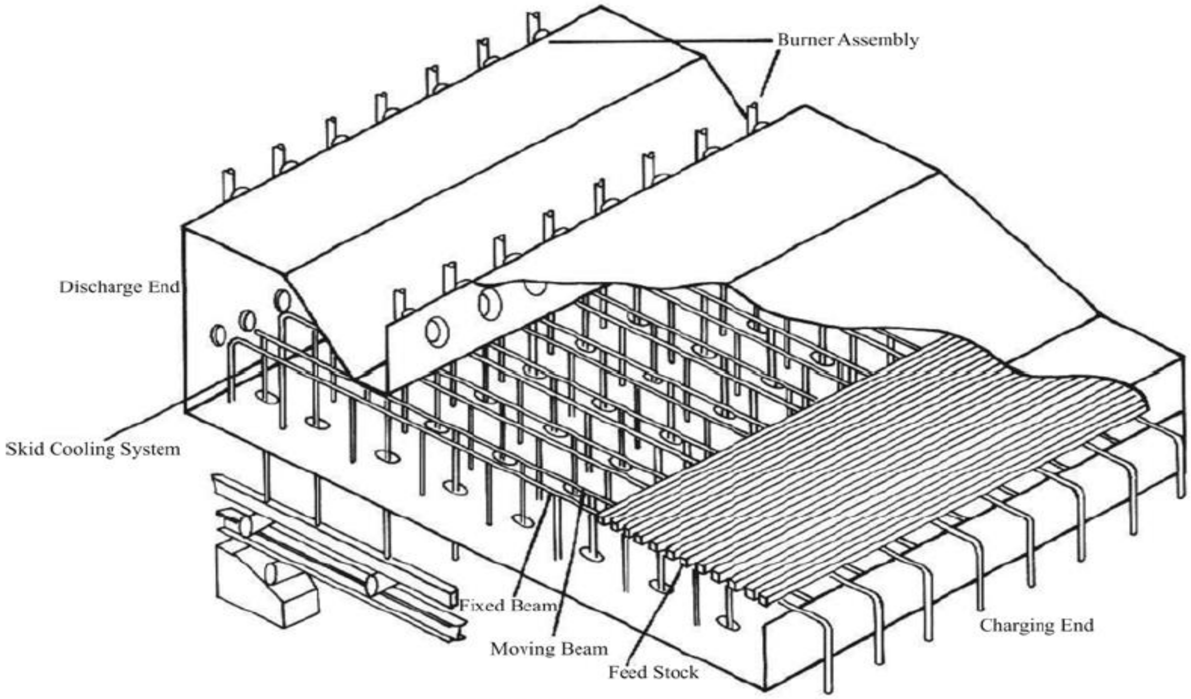


Two-zone (top and side fired) continuous furnace

In order to increase the throughput of the furnace, additional combustion zones are introduced by changing the profile of the furnace from single zone to multi-zone (two-zone, three-zone, four-zone and five-zonee furnaces) and placing the burner at more than one location, for example, front-fired, side-fired-bottom or top-fired furnaces.

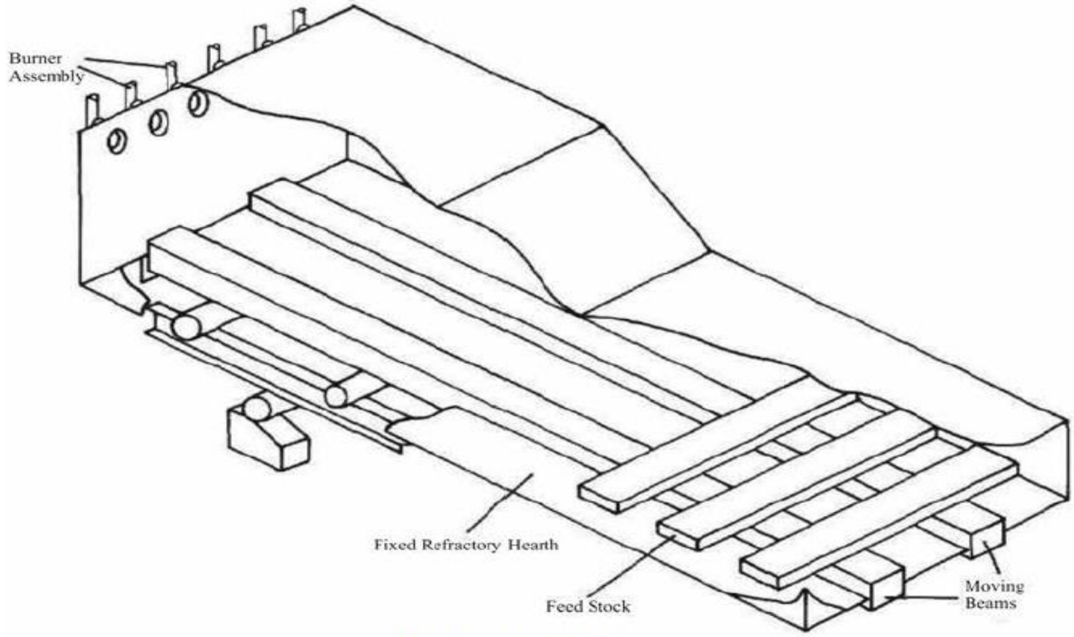
Walking beam furnaces:

Furnaces have mechanisms to transport the heating material by means of walking (mobile) beams which are called ‘walking beam furnaces’. The earlier version of walking beam furnaces was designed with alloy steel walking beams which were exposed directly to the furnace heat and were also subject to heat corrosion. Hence these furnaces had limitations to operate at maximum temperatures of about 1,050 °C. The existing type of walking beam furnaces used to reheat billets, blooms and slabs are made of water-cooled steel system lined with refractories so that only the refractories are exposed to heat. Alternatively, the beams and supports are constructed of water-cooled pipe sections with a provision on the top surfaces to keep away the hot material from direct contact with the water-cooled pipes. Walking beam furnaces are usually designed with end or side charging and discharging mechanisms. The beams can be actuated either hydraulically or mechanically. Cross firing with sidewall burners above and below the material stock are used. In some furnaces, the material is heated with radiant type roof burners or with burners placed in the roof and below the material.



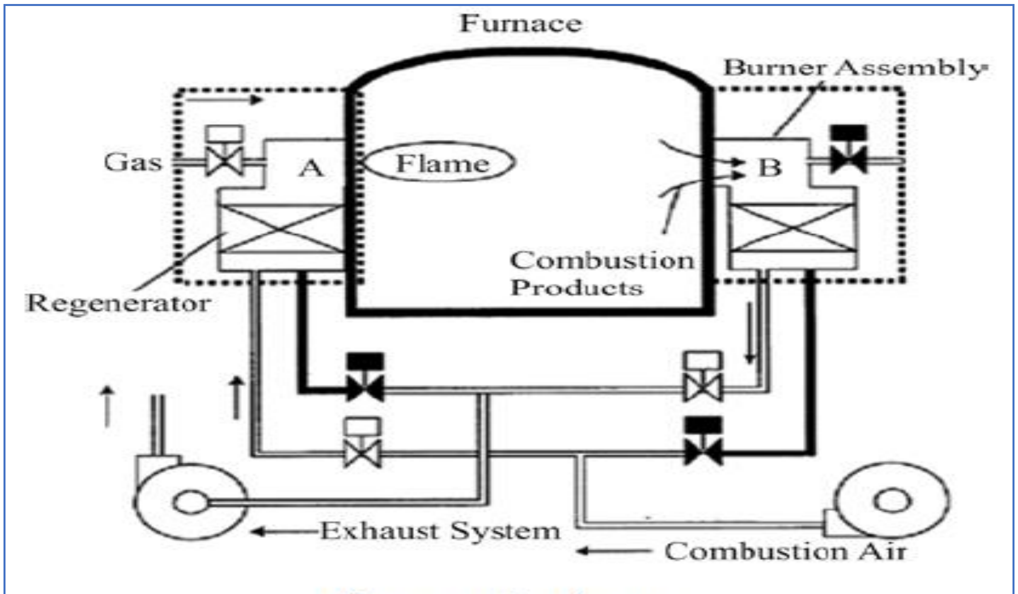
Walking beam furnaces

Walking hearth furnaces: These furnaces are similar to the walking beam furnaces while considering the passage of steel stock through the heating chamber. The basic difference lies in the method of conveyance i.e., steel stock rests on fixed refractory piers. These piers extend through openings in the hearth and their tops are above the hearth surface while the material is stationary in the furnace, thus allowing heat to circulate between the bottom surface of the work and hearth. For progressive movement of the material towards discharge end, the hearth is raised vertically to first contact the material and then raised further for a short distance above the piers. The hearth then moves forward to a preset distance, stops, lowers the material on to its new position on piers, continues to descend to its lowest position and moves backward to its starting position for the next stroke.



Walking hearth furnace

Regenerative furnaces: These are the modern era furnaces having high capacities based on the principles of heat recovery to a maximum limit of 1,000 –1,150 °C. Regenerative furnaces have two chambers, each containing refractory material called 'the checker' (either high alumina balls or honeycomb structure). While in one chamber, combustion gases pass through the checker and enter the furnace; in the other chamber, the checker is heated, or regenerated, with the outgoing hot exhaust gas. The furnace operates in two cycles. After each cycle (about 60 seconds), the flow is reversed so that the new combustion air can be preheated by the checker arrangement. Typical air preheat temperatures, depending on the number of ports are normally in the range of 1,000–1,150 ^{o}C.



Regenerative furnace

Rolling mills: There are three types of rolling mills in common use i.e., 2-Hi, 3-Hi, and 4-Hi mills. This classification is based on the mode of arranging rolls in the housings. Typically, one 2-Hi stand consists of 2 rolls, arranged one above the other. Similarly, a 3-Hi mill has 3 rolls and a 4-Hi mill has 4 rolls. 6-Hi, 12-Hi or 20-Hi mills are also designed but only for a specific use. Mills having 6 or more rolls are generally termed as cluster mills.

Cross-country mill**;** in the cross-country mills, the roll stands are located in a scattered manner. These mills are based on the concept of continuous rolling but the stands are placed so far apart that the piece must leave one set of rolls before entering the next. Such mills are useful for rolling sections that due to size or shape are not adaptable to loop rolling.

Continuous mill: In order to meet high production, it is common to install a series of rolling mills one after another in tandem, i.e., in a straight line. Since a different size reduction is taken at each stand, the strip is rolled simultaneously at a number of stands. This is called a continuous mill. Reduction takes place in several passes at the same time until the piece emerges as a finished shape from the last stand.

Semi-continuous mill: A semi-continuous mill comprises a reversing roughing stand for reducing the piece before entering the continuous mill and its reduction to a finished shape. Rolling mills can also be classified based on product types as per the following.

- Roughing or cogging mill: Producing semi-finished products like blooms, slabs, and billets.
- Section mill: Producing various sections like heavy, medium, and light structural sections (angles, channels, etc.) rounds and square bars and other sections used in applications like windows and pilings.

- Plate and sheet mill: This includes wide and medium strip mills.
- Tube mill: This is used for the production of both seamless and welded tubes.
- Merchant mill: This includes the production of rounds, bars, etc.

5.4 Heat Balance of Reheating Furnace

Heat balance of the reheating furnace is a mean to determine the thermal efficiency of the system and compare the relative heat losses. By making the comparison with an identical process, areas of inefficiency can be identified, where a change in operational control or equipment could lead to an improvement in the thermal efficiency of the furnace.

Heat input	Heat output
1. Combustion from fuel at Regenerative burner	Sensible heat of billet
2. Combustion from fuel at ordinary burner	Sensible heat of gas from regenerative burner
3. Preheated air by recuperator	Sensible heat of gas from ordinary burner
4. Sensible heat of air inlet	Heat loss in wall
5. Sensible heat of scale formation	Heat loss from opening
	Sensible heat into scale
	Other losses

Heat balance helps us to numerically understand the present heat loss and efficiency and improve the furnace operation using these data. Thus, preparation of heat balance is a pre-requirement for assessing energy conservation potential.

A typical heat balance of reheating is explained below; the data taken during the trial study is listed below;

Duration of trail	16 hours
Hydrogen in fuel	12%
Water content	0.5%
Calorific value of LSHS	10200kCal/kg
Specific gravity of LSHS	0.95
Specific heat of fuel	0.5 kCal/kg ^{0}C
Fuel consumption	5550 liters
Theoretical air required for combustion	14 kg of air /kg of fuel
Temperature of fuel before firing	100 ^{0}C
Temperature of furnace	1300 ^{0}C
Input material	93.5 T
Production	92T
Scale loss	1.6%
Specific heat of steel at 30^{0}C	0.11kCal/kg ^{0}C
Specific heat of steel at 1300^{0}C	0.158 kCal/kg ^{0}C
Specific heat of scale at 1300^{0}C	0.215 kCal/kg ^{0}C
Ambient air temperature	30^{0}C
Humidity of air	0.034 kg/kg of dry air
Atomizing air	700Nm^3/hr

Secondary air temperature	200 ^{0}C
Specific heat of air at 200^{0}C	0.24 kCal/kg ^{0}C
Oxygen in flue gas	4%
Flue gas temperature after pre heater	675 ^{o}C
Specific heat of flue gas	0.26 kCal/kg ^{0}C
Specific heat of water vapour	0.26 kCal/kg ^{0}C
Cooling water flow rate	28m^3/hr
Temperature difference	10 ^{0}C
Number of doors	2 nos.
Factor of radiation	0.7 for rectangular door
Area of opening A	1m^2
Diameter of furnace	10m
Height of furnace	2.5 m
Wall surface area	78.5m^2
Roof surface area	78.5m^2
Average wall temperature	65 ^{0}C
Average roof temperature	100 ^{0}C

Solution

Calculation of product rate

Production rate : 92/16
: 5.75T/hr

Calculation of fuel rate

Fuel rate : 5550/16
: 347 liters/hr

Calculation of specific fuel consumption

Specific fuel consumption : 347/5.75
: 60liters/ T of billet
: 60 X 0.95
: 57kg/T of billet

Calculation of specific atomizing air

Atomizing air flow rate : 700 Nm^3/hr
: 700 X 1.28
: 896 kg/hr
Specific atomizing air rate : 896/5.75
: 156 kg of air / T of billet

Calculation of specific secondary air

Theoretical air required for combustion : 14 kg of air /kg of fuel
Excess air : (4/ (21-4)) X100
: 24%

Total air supplied to furnace : 57 X (14 X (1+0.24))
: 991 kg of air /T of billet
Secondary air required for combustion : 991-156
: 835 kg of air /T of billet

Calculation of specific flue gas

Flue gas quantity : 997 +57
: 1408kg / T of billet

Calculation of specific water vapour

Water vapour carried over in flue gas **:** ($9H_2$+water content)/100
: ((9X12)+0.5)/100
: 1.085 kg/kg of fuel
: 1.085 X 57
: 62 kg/T of billet

Calculation of specific scale formation
Percentage of scale formation : 1.6%
: (5.75 X 0.016 X 1000) / 5.75
: 16 kg/T of billet

Calculation specific water flow rate
Cooling water flow rate : 28 m^3/hr
Specific cooling water : 28000/5.75
: 4869.6 kg/T of billet

Calculation of Heat Input

1. Combustion heat of fuel : 57 X 10200
   : 584,560 kCal/ T of billet
2. Sensible heat of fuel : 57 X 0.5 X (100-30)
   : 2006 kCal/ T of billet
3. Sensible heat of atomizing air : 156 X 0.23 X (30-30)
   : 0 kCal/ T of billet
4. Quantity of heat brought in by Charged steel : 1016 X 0.11 X (30-30)
   : 0 kCal/ T of billet
5. Heat of formation of scale : 16 X 1335
   : 21360 kCal/ T of billet

Total Heat Input : 1 + 2 + 3 + 4 + 5
: 5, 84,560 +2006+0+0+21,360
: 6, 07,926 kCal/T of billet

Calculation of Heat Output

1. Sensible heat of steel : 1000X 0.158 X (1300-30)
   : 2, 00,660 kCal/T of billet
2. Sensible heat of scale : 16X 0.215 X (1300-30)
   : 4, 369kCal/T of billet

3. Sensible heat of dry flue gas : (1048-62) X 0.26 X(675-30)
   : 1, 65,389kCal/T of billet
4. Heat loss due to formation of
   Water vapour from fuel : 62 X (584+0.48 X (675-30))
   : 55,564kCal/T of billet
5. Heat loss due to formation of
   Water vapour from air : 991 X 0.034 X 0.48 X (675-30)
   : 10,433kCal/T of billet
6. Heat taken away by cooling water : 4869.6 X 10
   : 48696kCal/T of billet
7. Calculation of radiation heat losses :
   - Radiation heat losses through furnace opening
     1 X 1X0.7X4.88((1573/101)^4 – (303 /100)^4)/5.75
     36,322 X 2 kCal/T of billet
     72,644 kCal/T of billet
   - Surface radiation loss
     Q = a X (T1-T2)^1.25+4.88 X E X (((T1+273)/100)^4 – ((T2+273)/100)^4)

Radiation heat losses through walls

2.2 X (65-30) ^1.25+4.88X0.8 X (((65+273)/100) ^4 – ((30+273)/100) ^4)
187.3 +4.88X0.8 X (130-84)
187.3 + 179.6
366.9 kCal/m^2 hr

Wall surface heat loss

78.5 X 366.9
28801 kCal/hr
28801/5.75
5009 kCal/T of billet

Radiation heat loss through roof

2.8 X (100-30) ^1.25+4.88X0.8 X (((100+273)/100) ^4 – ((30+273)/100) ^4)
567 + 4.88 X 0.8 X (193.6 - 84)
567 + 428
995 k Cal/m^2 hr

Roof surface heat loss

78.5 X 995
78108 kCal/hr
78108/5.75
13584 kCal/T of billet

Total Radiation losses from furnace – 5099+13584+72643 = 91236 kCal/T of billet

Total Heat Output = 1 + 2+ 3 + 4 + 5 + 6 + 7
200660 + 4369 +165389+55564+ 10433+48696+91236

576347 kCal/T of billet

Heat Balance Table

Heat Input			**Heat Output**		
Item	**kCal/T**	**%**	**Item**	**kCal/T**	**%**
Combustion Heat of fuel	584560	96.16	Sensible Heat of steel	200660	33.01
Sensible heat of fuel	2006	0.33	Sensible heat of Scale	4369	0.72
Sensible heat of Atomizing air	0		Sensible heat of dry flue gas	165389	27.21
Quantity of heat brought in by charged steel	0		Heat loss due to formation of water vapour from fuel	55564	9.14
Heat of formation of scale	21360	3.51	Heat loss due to formation of water vapour from air	10433	1.72
			Heat taken away by cooling water	48696	8.01
			Radiation heat loss	91236	15.01
			Others	31579	5.19
Total	**607926**	**100.00**	**Total**	**607926**	**100.00**

5.5 General Fuel Economy Measures in Furnaces

Typical energy efficiency measures for an industry with furnace is given below:

- Complete combustion with minimum excess air
- Correct heat distribution
- Operating t desired temperature
- Reducing heat loss from furnace openings
- Maintaining correct amount of furnace draft
- Optimum capacity utilization
- Waste heat recovery from the flue gases
- Minimum refractory losses
- Use of ceramic coating
- Use of energy-efficient burners

5.6 Case Studies

1. High-efficiency metallic recuperator with improved furnace design for Reheating furnaces

High-efficiency metallic recuperator with improved furnace design, redresses fundamental design imperfections (such as geometry and material of tubes inside the recuperator and the dimensions, refractory/insulation, combustion systems, etc. in the furnace) in reheating furnaces that lead to low hearth utilization, reduced heat input, and improper heat distribution as well as the resultant high specific fuel consumption (SFC) and scale loss. Outdated and inefficient furnace equipment is replaced with high-efficiency equipment like a metallic recuperator, proper refractory and insulation, and some automation and control system. All this is supplemented by an energy-efficient furnace design.

The investment required, potential reduction in fuel consumption, and the payback periods for this technology package are given below.

Improve the combustion efficiency by controlling excess air	
Existing condition	
Flue gas quantity (kg/hr)	2819
Flue gas temperature (°C)	1079
Heat in flue gas (kcal/hr)	739 573
Improved condition	installed a recuperator to recover the waste heat available in flue gas to preheat the combustion air
Flue gas temperature after waste heat recovery (ºC)	350
Flue gas temperature (ºC)	1079
Combustion air temperature (ºC)	400
Preheated air quantity (kg/hr)	5027
Heat recovered (kCal/hr)	337 836
Savings achieved (%)	30
Energy savings (kilolitres)	250
Cost saving (Rs million/year)	5.0
Investment (Rs million)	1.5
Simple payback period (months)	3.6

2. Application of Ceramic coating on furnace refractory

High-temperature, energy-efficient ceramic coatings for refractories—nolonger “theoretical” technology—are being used successfully in kiln and furnace, applications to reduce energy consumption, improve temperature uniformity, reduce maintenance, and increase production while improving product quality. By changing the re-radiative properties of a refractory lining in a furnace, these specialized ceramic coatings can provide energy savings of up to 15-20%, depending on the fuel being used, the furnace operation and configuration, and the production schedule. In addition, furnace heat-up time is decreased, and the service life of the high-temperature, ceramic-coated refractory is extended.

The investment required, potential reduction in fuel consumption, and the payback periods for this technology package are given below.

Application of Ceramic Coating	
Existing condition	
Fuel	LPG
Fuel consumption rate (kg/cycle)	61.5
Furnace temperature (°C)	740
Outside skin temperature (°C)	90
Improved condition	The inside furnace wall was coated with ceramic coating
Outside skin temperature (°C)	75
Fuel consumption rate (kg/cycle)	56.7
LPG saving (kg/year)	14520
Cost saving (Rs million/year)	0.508
Investment (Rs million)	0.075
Simple payback period (months)	1.8

3. **Improve the combustion efficiency by controlling excess air by online oxygen analyzer :**

In a furnace the fuel consumption is depends upon the status of combustion, excess level and flue gas temperature. The quantity of air required for burning fuel, based on its combustion and the chemical balance of reactions with oxygen is known as the stoichiometric or theoretical air requirement. Ideally, this quantity of air is sufficient to completely burn the fuel. But in practice, it has been observed that combustion is not complete unless some excess air is supplied to the system. The quantity of this additional air affects the mass flow rate of the flue gases. Higher excess air than optimum will reduce flame temperature, furnace temperature and heating rate. On the other hand, if the excess air is less, then un burnt components in flue gases will increase and would be carried away in the flue gases through stack. The following are the measures to effectively control the excess air levels:

1. Replacing the feed metering pumps in pre-heating and soaking zones and rectifying the pumps in heating & soaking zones.
2. Airflow meters to be calibrated.
3. Oxygen percentage is shown in the control system to be synchronized with the installed on-line oxygen analyzer.
4. Air-fuel ration to be maintained in auto mode based on temperatures in different zones.

The quantity of excess air in flue gases can be determined by measuring the percentage of either O_2 or CO_2 in the flue gas.

The investment required, potential reduction in fuel consumption, and the payback periods for controlling excess air by providing online analyzer are given below.

Improve the combustion efficiency by controlling excess air	
Existing condition	
Furnace capacity (T/hr)	50
Fuel	Biogas (64% methane)
GCV of fuel (kcal/Nm^3)	5300
Fuel consumption rate (Nm^3/hr)	266
Furnace pressure (mm WC)	-7
Oxygen percentage in flue gas	7.2
Excess air level (%)	52.2
Thermal efficiency (%)	72.8
Improved condition	Excess air level was controlled by adjusting ID and FD dampers. This improved the furnace pressure from negative to slightly positive, thereby eliminating air infiltration
Oxygen percentage in flue gas	3.3
Excess air level (%)	18.6
Pressure inside the furnace (mm WC)	+1.0
Biogas consumption (Nm^3/hr)	242
Increase in thermal efficiency (%)	2.04
Fuel saving (Nm^3/h)	24 (39.62 kg/h of coal)
Cost saving (Rs lakh/year)	6.93
Investment (Rs lakh)	Nil
Simple payback period (months)	Immediate

4. Use of Regenerative burner system in place of tradition burners

Regenerative burner system	
Existing Condition	
Fuel	LDO
Burner turndown ratio	3:1
Fuel consumption (litres/h)	300
Improved condition	New Regenerative burner with high turn down ration of 7:1 and a blower of 5 HP at 40-inch WC pressure were installed
LDO savings (litres/h)	30 (10%)
LDO saving (litres/year)	90 000
Cost saving (Rs million/year)	1.17
Investment (Rs million)	0.1
Simple Payback period (months)	1

Regenerative burners use the heat of flue gases to pre-heat the combustion air and gases going to the burners thus optimizing the heat input at the source itself. Regeneration uses a pair of burners in cycle to alternately heat the combustion air or recover and store the heat from the furnace exhaust gas. Air pre-heat temperatures up to 1000 °C are achievable resulting in exceptionally high thermal efficiency.

The investment required, potential reduction in fuel consumption, and the payback period for this technology package are given below

5. Use biomass gas as fuel in oil-fired reheating furnaces

The biomass gas production from biomass waste is in some sense a revolution, as there existed no precedence of using biomass gas as the primary fuel in such an energy-intensive process as steel re-rolling. Targeted mainly at oil-fired furnaces, the package replaces furnaces oil with producer gas from biomass briquettes, made with agricultural and forestry residue. The use of producer gas ensures proper combustion, lowering burning loss. The package, which comes with improved furnace design, also eradicates emission-related metrics, because bioenergy is considered a net-zero CO_2 emission fuel.

Given below are the investment required, potential reduction in fuel consumption, and the payback period for this biomass-based technology package

Use of biomass gas in place of oil fired re heating furnaces	
Investment for required for high efficiency metallic recuperator	Rs 15 -20 million
Reduction in fuel consumption (per tonne of furnace throughput)	20 – 25% (net zero CO_2 emission)
Simple Payback Period	6 – 12 months

6. Hot charging of continuous cast billets

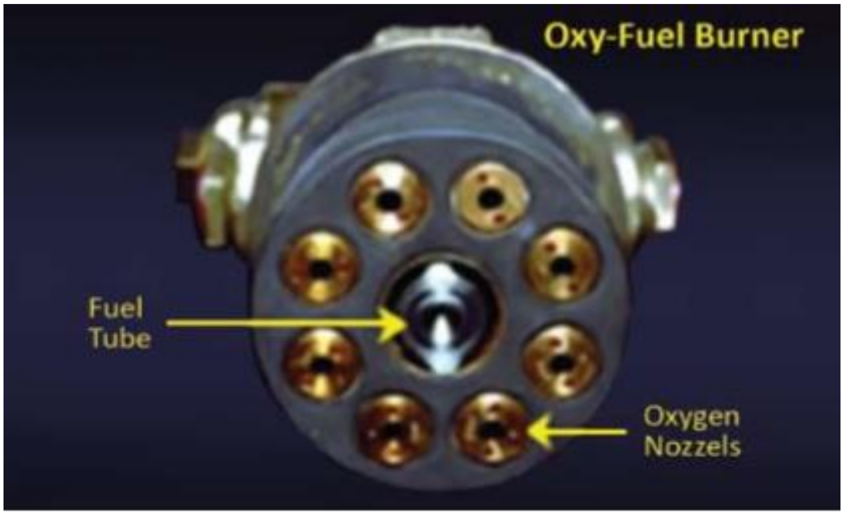
In virtually every re-rolling mill, billets and ingots are cold charged in re-heating furnaces. This means heating billets from room temperature to 1200 °C, leading to significant wastage of sensible heat. The hot charging process offers a solution that enables re-heating of hot billets as they emerge from the caster at temperatures of 600–800 °C, resulting in reduced fuel consumption for re-heating. The package also has the provision of a buffer furnace to compensate for mill delays.

The investment required, potential reduction in fuel consumption, and the payback periods for this technology package are given below.

Hot charging of continuous cast billets	
Investment for required for high efficiency metallic recuperator	Rs. 30 million
Reduction in fuel consumption (per tonne of furnace throughput)	30%
Simple Payback Period	6 months

7. Oxy-fuel combustion system

Recuperators are normally used to increase combustion air temperature. This results in heat loss through nitrogen in conventional air-fuel burner systems. The oxy-fuel burners developed under this package partly use oxygen instead of combustion air and thus eliminate heat loss through nitrogen (Figure A). In comparison to air-fuel flame temperature, the oxy-fuel burner flame can achieve much higher temperatures. The furnace thus operates at high temperatures which increases productivity, lowers retention time, and cuts down scale loss.



The investment required, potential reduction in fuel consumption, and the payback periods for Oxy-fuel combustion system are given below

Oxy-fuel combustion system	
Investment for required for Oxy-fuel combustion system	Rs. 25 – 50 million
Reduction in fuel consumption (per tonne of furnace throughput)	25 – 30 %
Simple Payback Period	6 -12 month

8. Top-and-bottom firing system

In typical pusher type furnaces, burners are located at the top. In the case of billets with higher cross-sections, this results in improper heating and soaking. The higher retention of charge in the furnace leads to higher levels of Specific Fuel Consumption (SFC) and scale loss. This package provides heat input into the furnace from both top and bottom, creating uniformity of heating charge, lower scale loss and fuel consumption, and increased furnace productivity (Figure B).

Figure 5.5: The top and-bottom firing system in use in a steel re-rolling mill

The investment required, potential reduction in fuel consumption, and the payback periods for this top-and-bottom firing system are given below.

Top and-bottom firing system	
Investment for required for Oxy-fuel combustion system	Rs. 50 – 60 million
Reduction in fuel consumption (per tonne of furnace throughput)	25 – 30 %
Simple Payback Period	12 -14 month

5.7 Conclusion

Energy saving potential in steel re-rolling mills is to the tune of 6% to 24%. This can be achieved through instrumented energy audit and implementation of energy saving measures.

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