ENERGY DEMAND MANAGEMENT AND CONSERVATION MANUAL FOR INDUSTRY AND BUILDINGS

Prepared for:

The United States Agency for International Development

Prepared by:

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FOREWORD

Most of this manual is based on a course book prepared for a 2-week energy demand management and conservation training program held in Sri Lanka in December 1983. This program, sponsored by the Sri Lankan Ministry of Power and Energy and the United States Agency for International Development, combined classroom sessions with a brief introduction to on-site energy auditing. Many aspects of this manual have thus been tested in real life situations and the lessons learned incorporated in this general version.

The large number of individuals both in the United States and abroad who have participated in the preparation of this document makes individual acknowledgements impossible. Hagler, Bailly & Company wishes, however, to express its appreciation to the 40 Sri Lankan engineers who endured the course; Dr. Mohan Munasinghe, Senior Energy Advisor to H.E., the President of Sri Lanka; and Pamela Baldwin of the Office of Energy of the U.S. Agency for International Development for their special contributions in this effort.

Any comment on this manual is welcomed and should be sent to: Director, International Services, Hagler, Bailly & Company (address on back cover).

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LIST OF EXHIBITS

SESSION 1: INTRODUCTION

The successful definition, implementation, and management of an industrial or commercial energy conservation program requires a proper framework and baseline for identifying and evaluating energy conservation opportunities. Energy cannot be saved until it is known where and how it is being used and when and where its efficiency can be improved. In most cases, such knowledge and baseline can only come from a comprehensive and detailed survey — or energy audit — of energy uses and losses.

Having conducted an energy audit does not, however, constitute in itself an energy conservation program. A number of other conditions must also be met. First, there must be a will to save energy. Second, viable energy conservation projects must be evaluated according to the company's financial guidelines. Third, financing must be available, and fourth, plant management and staff must be committed to continuing the energy rationalization effort well beyond project implementation, as the benefits of good projects can be lost as quickly as they are gained.

Building and industrial plant managers and engineers can play a key role in energy conservation endeavors, and their awareness and knowledge of a broad range of related matters is of utmost importance. This manual is designed primarily to assist them in carrying out their efforts to identify, implement, and manage efficient energy demand and conservation programs in their facilities. As such, the content of the manual embraces a broad variety of technical, economic, financial, and managerial subjects. This manual can also be used as a support book for a training course in energy management and conservation. Appendix 1.A is a possible agenda for a 9-day course including plant visits and panel discussions in addition to the 22 sessions that make up this manual. These sessions are organized in the following order:

Session 2: Engineering Refresher

Session 3: Financial and Economic Refresher

Session 4: Energy Performance of Thermal Equipment

Session 5: Power Generation and Electrical Equipment Performance

Session 6: Industrial Energy Management

Session 7: Energy Conservation Potential in Major Energy-Consuming Industries

Session 8: Introduction to Energy Auditing in Industrial Plants

Session 9: Industrial Energy Auditing -- Instrumentation

Session 10: Data Analysis

Session 11: Combustion Equipment and Boilers

Session 12: Furnaces and Kilns

Session 13: Dryers

Session 14: Steam Systems, Insulation, Waste Heat Recovery Systems, and Thermal Fluid Heaters

Session 15: Coal Conversion

Session 16: Wood Burning

Session 17: Waste Burning

Session 18: Biomass Gasification

Session 19: On-Site Industrial Power Generation

Session 20: Electricity Use, Part 1 -- Energy Performance of Various Types of Equipment

Session 21: Electricity Use, Part 2 -- Energy Management in Hotels and Other Large Buildings

Session 22: Corporate Energy Management -- Program Implementation.

APPENDIX 1.A: ENERGY DEMAND MANAGEMENT AND CONSERVATION TRAINING COURSE: A POSSIBLE AGENDA*

DAY 1 BASIC CONCEPTS IN INDUSTRIAL ENERGY MANAGEMENT

8:30-9:00 <u>Introductory Remarks</u>

9:00-10:00 <u>Industrial Energy Management: National Perspective</u>

Discussion of the importance of energy management from a national perspective — supply/demand outlook, role of industry, role of industrial energy conservation, and conservation potential and targets.

BREAK

10:30-12:00 <u>Engineering Refresher (Session 2, Part I)</u>

Basics in thermal, mechanical, and electrical engineering.

LUNCH

1:00-2:30 <u>Engineering Refresher (Session 2, Part II)</u>

Continuation of the morning session.

BREAK

3:00-4:30 <u>Financial and Economic Refresher (Session 3)</u>

Basics in economic evaluation procedures from the national and corporate perspectives. Energy price scenarios and the use of programmable pocket calculators and microcomputers for investment analysis are discussed.

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*See Exhibit 1.A for synopsis.

Exhibit 1.A

Energy Demand Management and Conservation Training Course: A Possible Agenda

Day	Main Topic	Morning Session		Afternoon Session		Evening
1	Basic Concepts	Introductory Remarks; Industrial Energy Management: National Perspective	Engineering Refresher (Part I)	Engineering Refresher (Part II)	Financial and Economic Refresher	Reception
2	Major Energy-Using Equipment	Energy Performance of Thermal Equipment	Power Generating and Electric Equipment Performance	Industrial Energy Management	Energy Conservation Potential in Major Energy-Consuming Industries	
3	Plant Auditing	Introduction to Energy Auditing in Industrial Plants	Data Gathering and Instrumentation (Part I)	Data Gathering and Instrumentation (Part II)	Data Analysis	
4	Thermal Energy Management	Combustion Equipment and Boilers	Furnaces and Kilns	Dryers	Steam Systems; Insulation; Waste Heat Recovery Systems; Thermal Fluid Heaters	
5	Fuel Substitution	Coal Conversion	Wood Burning	Waste Burning	Biomass Gasification	
6	Electricity Management	On-Site Generation and Cogeneration	Electricity Use (Part I)	Electricity Use (Part II)	Introduction to Plant Visit	
7	Plant Visit/ Audit		Plant Visit/Introductory Audit			
8	Analysis of Plant Audit	Data Aggregation and Validation	Energy and Material Balances	Efficiency Computations	Identification and Evaluation of Conservation and Fuel Substitution Measures	Reception
9	Panel Discussion/ Course Wrap-Up	Corporate Energy Management: Program Implementation	Panel Discussion	Course Review and Summary	Concluding Remarks; Presentation of Certificates	

SOURCE: Hagler, Bailly & Company.

7:30 **Reception**

DAY 2 MAJOR ENERGY-USING EQUIPMENT

8:30-10:00 **Energy Performance of Thermal Equipment (Session 4)**

Overview of boilers, furnaces, kilns, dryers, and other thermal equipment.

BREAK

10:30-12:00 **Power Generation and Electric Equipment Performance (Session 5)**

Overview of power generation efficiency and electric motors, transformers, lighting, air conditioning, compressors, etc.

LUNCH

1:00-2:30 **Industrial Energy Management (Session 6)**

Review of all the major energy-intensive industries.

BREAK

3:00-4:30 **Energy Conservation Potential in Major Energy-Consuming Industries (Session 7)**

Continuation of the previous session, with an emphasis on efficiency standards and associated savings potential.

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DAY 3 PLANT AUDITING

8:30–10:00 **Introduction to Energy Auditing in Industrial Plants (Session 8)**

Brief overview of the purpose of an audit, and the different types of audits. Steps in a detailed Energy Audit Program will be presented together with the basic requirements for successful corporate programs.

BREAK

10:30–12:00 **Data Gathering and Instrumentation (Session 9, Part I)**

Review of typical data sources (invoices, internal statistics, meters) and measuring equipment and procedures. The use of portable diagnostic instruments, as well as fixed instrumentation, will be presented. Calibration of instruments will also be discussed. Actual diagnostic instruments will be available for demonstration and use.

LUNCH

1:00–2:30 **Data Gathering and Instrumentation (Session 9, Part II)**

Continuation of the morning session.

BREAK

3:00–4:30 **Data Analysis (Session 10)**

Discussion of what to do with the data collected and how to assess their validity and reliability. Theoretical and practical examples will be used to construct energy balances, compute efficiency, calculate the savings potential, and establish achievable conservation targets. The use of programmable pocket calculators will be demonstrated together with a discussion of microcomputer applications and software packages. Participants are requested to bring their calculators.

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DAY 4 THERMAL ENERGY MANAGEMENT

8:30-10:00 Combustion Equipment and Boilers (Session 11)

Discussion of factors influencing the performance of burners and boilers; "housekeeping" measures; equipment modifications and replacement; state-of-the-art in burners, controls, and boilers. Case presentations of multifuel (e.g., wood/oil) boilers will be presented.

BREAK

10:30-12:00 Furnaces and Kilns (Session 12)

Continuation of the previous session. Focus on furnaces and kilns.

LUNCH

1:00-2:30 Dryers (Session 13)

Continuation of the morning session. Focus on dryers.

BREAK

3:00-4:30 Steam Systems; Insulation; Waste Heat Recovery Systems; and Thermal Fluid Heaters (Session 14)

Continuation of the previous sessions. Focus on steam traps and lines, insulation, heat exchangers, other recovery devices, and thermal fluid heating systems.

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DAY 5 FUEL SUBSTITUTION

8:30-10:00 <u>Coal Conversion (Session 15)</u>

System types, performances, and economics of coal conversion, including a discussion of coal/oil and coal/water mixtures.

BREAK

10:30-12:00 <u>Wood Burning (Session 16)</u>

System types, performances, and economics of wood burning will be presented in detail.

LUNCH

1:00-2:30 <u>Waste Burning (Session 17)</u>

Discussion of nonconventional waste fuel-burning systems, their performance, and economics. Presentation of case studies.

BREAK

3:00-4:30 <u>Biomass Gasification (Session 18)</u>

Discussion of the types of systems, performances, and economics of wood, charcoal, and agricultural residues gasifiers. Their application for the generation of electricity and mechanical power (fixed or mobile), as well as heat, will be reviewed. Safety aspects will also be discussed.

DAY 6 ELECTRICITY MANAGEMENT

8:30-10:00 <u>On-Site Industrial Power Generation (Session 19)</u>

Detailed review of the technical and economic characteristics of industrial electricity generating systems, including diesel engines, boiler/steam turbines, and other topping and bottoming cogeneration systems.

BREAK

10:30-12:00 <u>Electricity Use (Session 20)</u>

Brief discussion of industrial load profiles followed by a review of load management techniques.

LUNCH

1:00-2:30 <u>Electricity Use (Session 21)</u>

Continuation of the morning session. Presentation of practical and economic options to reduce energy costs in large hotels and commercial buildings.

BREAK

3:00-4:30 <u>Introduction to Plant Audit</u>

Preparation to the next day's visit and audit of an industrial plant. Brief description of the plant process and major energy-using operations. Organization of the audit and team assignments.

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DAY 7 PLANT VISIT AND AUDIT

8:30-4:30 **Plant Visit and Audit**

After a general visit of a plant, the participants will be grouped into teams, and each team will be responsible for conducting a part of the audit (e.g., review of energy management organization, invoices, boiler operation, compressors, electric equipment).

DAY 8 ANALYSIS OF PLANT AUDIT

Participants will apply the lessons and tools presented in the previous days. The objective is to organize and analyze the data collected during the field audit and to identify specific cost-effective measures to save energy at the plant. Participants are requested to bring their calculators.

8:30-10:00 **Data Aggregation and Validation**

Participants will review the information gathered by each team, assess the data reliability, and identify information gaps.

BREAK

10:30-12:00 **Energy and Material Balances**

Participants will initiate the construction of a detailed energy and material balance for entire plant visited on Day 7 and for each major unit of operation in that plant.

LUNCH

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1:00-2:30 **Efficiency Computations**

Participants will assess the efficiency of each major unit of operation in the plant visited and assess the potential for energy savings.

BREAK

3:00-4:30 **Identification and Evaluation of Energy Conservation and Fuel Substitution Measures**

Participants will compile a list of measures to capture potential savings in the plant audited on Day 7. To the extent possible, several of the measures will be analyzed in greater detail, and pro forma economic evaluations will be performed.

7:30 **Reception**

DAY 9 PANEL DISCUSSION AND COURSE WRAP-UP

8:30-10:00 **Corporate Energy Management: Program Implementation (Session 22)**

Using the plant audited as an example, the discussion will focus on the management and organizational aspects of implementing an energy conservation program. A presentation will be made to the audited plant's management.

BREAK

10:30-12:00 **Panel Discussion**

Open discussion of the successes and difficulties associated with energy management programs -- the role of management and of the government will be discussed.

LUNCH

1:00–1:30 <u>Course Review and Summary</u>

1:30–2:30 <u>Concluding Remarks</u>

Each participant will be asked to fill out a simple evaluation of the training course. Each participant will be presented with a certificate of attendance of the course. Further activities will be presented.

SESSION 2

ENERGY DEMAND MANAGEMENT AND CONSERVATION

TRAINING COURSE

Engineering Refresher: Thermodynamics, Heat and Mass Transfer

1. Introduction

In these refresher lectures, we lock at the Engineering Science which would be of relevance for the rest of the course. The various topics are not covered in any great depth, but are sufficient for a course of this nature which has a st ong bias towards actual practice.

2. Basic Laws and Equations

Heat is something which appears at the boundary of a system when a system changes its state due to a difference in temperature between itself and its surroundings.

Work is something which similarly appears at a boundary when the change of state takes place under the action of a force.

Work can be

- The rotation of a shaft.
- The compression or expansion of a gas acting upon a piston.
- The action of a gas or liquid upon a turbine wheel, pump impeller etc.
- Electrical work.
- Stirring work.

The "system" always has a fixed boundary, across which work and heat interactions take place see fig. 1.

1st Law

When any closed system is taken through a cycle, the nett work delivered to the surroundings is proportional to the nett heat taken from the surroundings.
(A closed system is one in which no material transfers take place)

$$Q = W \quad - \quad (1)$$

by the 1st law, work and heat are fundamentally equivalent. The first law also enables us to identify the property internal energy, which is possessed by the material within the boundary.

ie. $Q - W = U_2 - U_1$ (non cyclic process) - (2)

Where 1 and 2 are the starting and end states of the process and U is the internal energy.
Note that the sign convention is that heat into the system is positive while work output is negative and vice versa. Since in practical processes we utilise a quantity of heat to produce work, we can also define a process or cycle efficiency as follows:

$$\text{Efficiency} = \frac{W_{out}}{Q_{in}} \quad \text{———(3)}$$

When W_{out} is the nett (or useful) work out in any process and Q is the nett heat input to the process.

2nd Law

This states that it is impossible to construct a system which will operate in a cycle, extract heat from a reservoir and do an equivalent amount of work on the surroundings.

(an alternative statement is that it is impossible to construct a system which will operate in a cycle and transfer heat from a cooler to a hotter body wi ut work being done on the system).

The second law showsthat work is a more valuable form of energy than heat, because while all work can be converted to heat, the converse is impossible by means of a cycle device.

The first law prohibits perpetual motion machines of the 1st kind (PMM 1), see fig. 2. The second law goes further, prohibits (PMM 2) type machines and says that the only allowable cyclic machines are the third type.

When a process (cyclic or non-cyclic) takes place, there are changes in the system and its surroundings e.g. when a heat engine operates, work is produced and energy is taken from a chemical fuel. Hence the final state of the system and its surroundings is different to the initial state.

If the system and its surroundings can subsequently be restored to the original state (without further expenditure of Energy to do so) then the process is called a reversible process. Needless to say, this does not arise in practice generally because of

a) Friction

b) Heat transfer across finite temperature differences (which always leads to irreversibility, as a consequence of the 2nd Law).

It is found that work output is a maximum in any reversible non-cyclic process as compared with a similar irreversible process. A cyclic device with an external work output also has the greatest efficiency when it is reversible. It is found that all reversible heat engines working between the same temperature reservoirs have the same efficiency and because of this, the efficiency is a function only of the temperature of the heat reservoirs.

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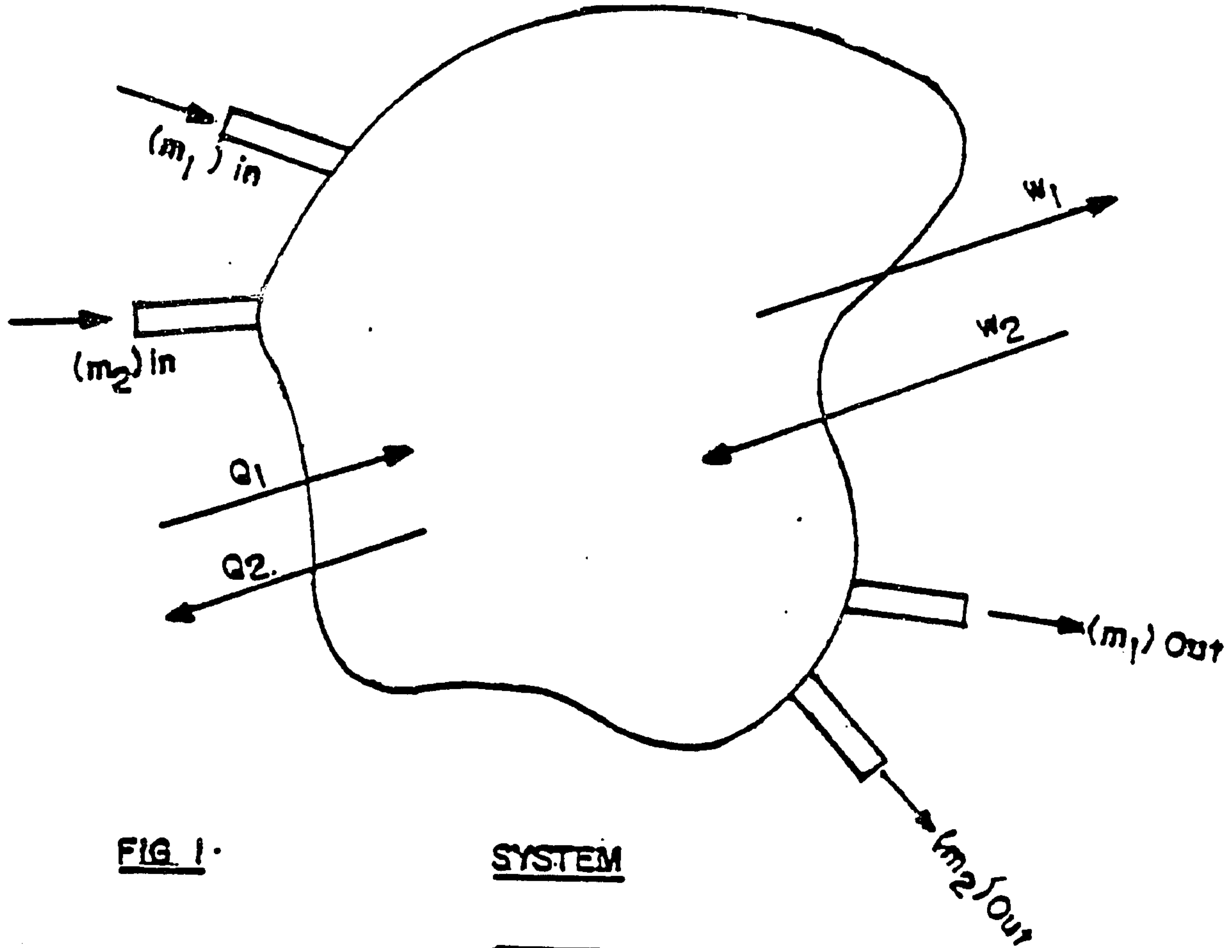
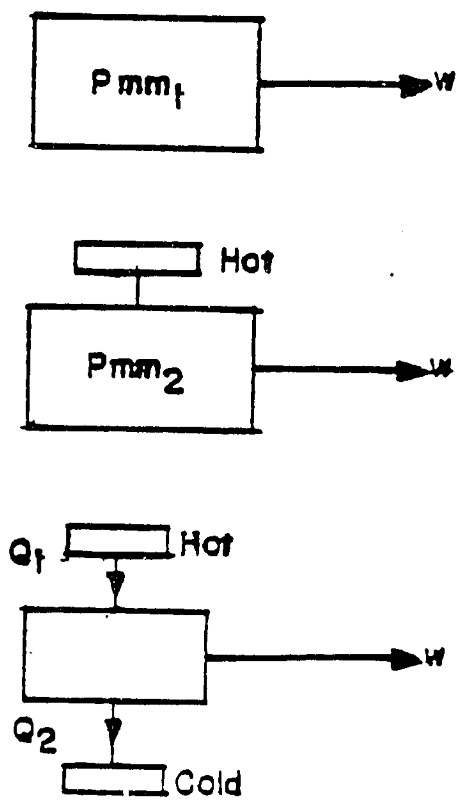


FIG. 1· SYSTEM



Heat Engine

FIG 2· CYCLIC DEVICES

$Q_1 - Q_0 - W = 0$, $W = Q_1 - Q_0$

$$\text{Efficiency} = \frac{W}{Q_1} = 1 - \frac{Q_0}{Q_1}$$

$$= 1 - \frac{T_0}{T_1} \text{ ------ } (4)$$

$$\text{also } \frac{Q_0}{Q_1} = \frac{T_0}{T_1} \quad \text{ie} \quad \frac{Q_0}{T_0} = \frac{Q_1}{T_1} \text{ ------ } (5)$$

The second law also enables us to define a property called Entropy which for a reversible process is found to be such that

$$\int_1^2 \frac{dQ}{T} = \text{change in entropy}$$
$$= S_2 - S1 \text{ ------ } (6)$$

For a reversible cycle,
change is Entropy $= \frac{dQ}{T} = 0$ from (5) above.

From equation (4), with a fixed cold reservoir temperature T_0 and considering a fixed quantity of heat Q in the upper reservoir, work done with two different upper reservoir temperature T_1' and T_1"
would be

$$W' = Q\left\{1 - \frac{T_0}{T_{1'}}\right\}$$
$$W'' = Q\left\{1 - \frac{T_0}{T_{1''}}\right\}$$

if $T_{1''} > T_{1'}$, $W'' > W'$

The greater the temperature of the upper reservoir, the greater the efficiency.

Hence we can see that in a common sense way $\frac{\Delta Q}{T}$ or $\frac{Q}{T}$ is a measure of the quality of the energy that we have at hand, in terms of its capacity to do work. Hence entropy is a measure of quality, just as much as internal energy is a measure of the quantity, of energy which is a present in given circumstances.

Entropy is also a property of a system, in the same way that energy is a property.

Units of heat and work in the universal S I system are Joules/Kg. Units of internal energy are the same. Units of entropy are $\frac{\text{Joules}}{\text{Kg } ^oK}$. In our work, these units will be used throughout.

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3. Processes and Efficiencies

From the 1st law

$$Q - W = \Delta U = (U_2 - U_1) \text{ ---------(2)}$$

Work done by a gas in a piston/cylinder mechanism, is, for a small movement

$$= P.\ dV,\ (\text{Fig. 3}) = \text{--------(7)}$$

(7) in (2).

$$dQ - pdv = du$$

$dQ = du + pdV$ -------(8) The quantity $du + pdv$ or $U + PV$ is called Enthalpy, with the symbol h or H. $U + PV$ occurs so often in many processes, especially flow processes, that it has been found useful to define a new quantity in this way.

Units of enthalpy in the SI system are the same as units of internal energy ie $\frac{J}{Kg}$. Note that pressure is $\frac{N}{m^2}$ and volume is M^3.

$\therefore$ PV ------- Nm -------J.

Considering an open system ie. one in which flow of materials is also present (Fig 1), by the 1st Law,

$$Q - W + \frac{dU}{dt} = \sum_{out} \dot{m}\ (u + pv + \tfrac{1}{2}c^2 + gz) - \sum_{in} \dot{m}\ (u + pv + \tfrac{1}{2}c^2 + gz) \text{---(8)}$$

$\dot{m}$ = mass flow rate (in or out)

u = internal energy of flow per unit mass

p = static pressure in the flow

c = velocity of the flow per unit mass

v = specific volume of the flow per unit mass

z = potential energy flow of the system

U = internal energy of the system

Q = Nett heat inflow to the system

W = " work outflow from the system

The c^2 and gz terms represent kinetic and potential energy. By including these, we acknowledge the interconvertibility of KE and PE with thermal energy, (represented by U and V). The term $\frac{dU}{dt}$ takes into account the fact that there may be storage or depletion of energy within the system.

The pv term is included because external work is done on the system by the fluid at all incoming points and by the system on all outflowing fluid. However, this work transfer is incorporated with the fluid properties because it is an automatic consequence of the flow.

The law of conservation of mass also gives

$$\frac{dM}{dt} = \sum_{in} (\dot{m}) - \sum_{out} (\dot{m})$$

Where M is the total mass contained within the system boundary at any time.

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Since most processes of interest to us would have steady - state - conditions within the boundary, we would use the relationships (8) and (9) in the form

$$\sum_{in} (\dot{m}) = \sum_{out} (\dot{m})$$

$$\dot{Q} - \dot{W} = \dot{m}\left[(h + \tfrac{1}{2}c^2 + gz)_{out} - (h + \tfrac{1}{2}c^2 + gz)_{in}\right] \text{-------}(10)$$

<u>Equations of State</u> relate the material properties of substances to one another. In the case of a simple fluid (one which has only a single chemical constituent), it is an experimental fact that only two properties are necessary to determine the whole state of the fluid (ie all the other properties).

For a (so-called) ideal gas, a simple algabraic relationship links the properties ie

$$PV = mRT \text{ ------- } (12)$$

R is a constant for a particular gas and is known as the gas constant. Because of the rule (Avogadro's rule) that all gases contain the same <u>no</u>. of molecules at the same temperature and pressure, there is also a Universal Gas Constant.

$$R_0 \text{ where } R_0 = 8.314 \frac{KJ}{Mol\ \ ^oK} \text{ -------}(13)$$

$$R = \frac{R_o}{M} \text{ -------}(14)$$

M is the molecular wt. of the particular gas.

Other important relationships are as follows:

2nd Law $\quad ds = \dfrac{dQ}{T} \quad$ from $\quad$ (6)

1st Law $\quad dQ = du + pd$

$$\therefore \quad Tds = du + pdv \text{ and } Tds = dh - vdp \text{ -------}(14)$$

For an ideal gas

$$\left.\begin{aligned} du &= C_v\ dt \\ dh &= C_p dT \end{aligned}\right\} \text{-------}(15)$$

$$(14) \text{ and } (15) \quad ds = \frac{dh}{T} - \frac{vdp}{T} = \frac{QdT}{T} - \frac{R}{} dp$$

$$\therefore \quad S_2 - S_1 = C_p \text{ Ln } \frac{T_2}{T_1} - R\text{Ln } \frac{P_2}{P_1} \text{ -------}(16)$$

Eqn.(16) enables calculation of the entropy change in any process where the medium can be regarded as an ideal gas. This relationship can be used in all calculations dealing with air, CO_2, CO, H_2 etc. and even with H_2O when the process is gaseous.

In general, for real fluids the ideal gas assumption is inaccurate. Also, in the case of water/steam, Ammonia and various refrigerant fluids, much engineering interest is centred on mixtures in which liquid and vapour coexist. The properties of these fluids are either obtained from Tables or charts which relate two properties to one another. As an example, consider the Temperature - entropy and enthalpy - entropy chart for water/steam, as shown in Figs (4) and (5).

The region bounded by the (semi-parabolic) curve is the one in which liquid and vapour coexist. The left hand side of this curve is known as the saturated liquid line and the right hand side, the saturated vapour line. On these two lines, the state (all the properties) of a fluid are completely determined when only one variable is specified. In the wet region (in between), two properties other than P and T together are required. P and T are insufficient because they are interdependent, in this region. In all other areas, any two properties (including P and T together) are quite sufficient to determine the fluid properties.

An important factor in dealing with substances in the wet region is dryness fraction, which is

$$x = \frac{\text{mass of saturated vapour}}{\text{Total mass of vapour}}$$

Since other properties such as enthalpy and entropy are per unit mass

$$h = (1-x)h_f + xh_g$$

$$s = (1-x)s_f + xs_g$$

$$u = (1-x)u_f + xu_g$$

Where f and g denote the respective values on the saturated liquid and vapour lines (see Fig 4).

Note that h-s diagrams are especially useful in analyses of steady flow processes in which enthalpy changes take place.

Processes. In order for heat and work interactions to take place, material within a system boundary must change its state. There are various processes by which changes of state can take place.

Table (1) gives relationships for when the material is an ideal gas and when the process is of the closed or non flow type. However, these relationships can be used for most real gases when the process is wholly dry.

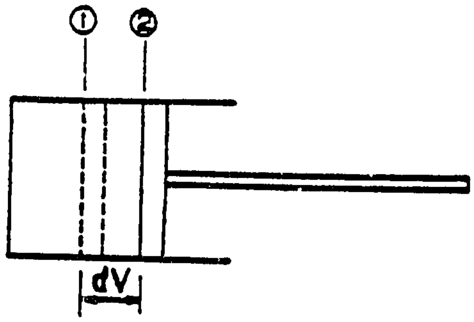

FIG 3· PISTON & CYLINDER

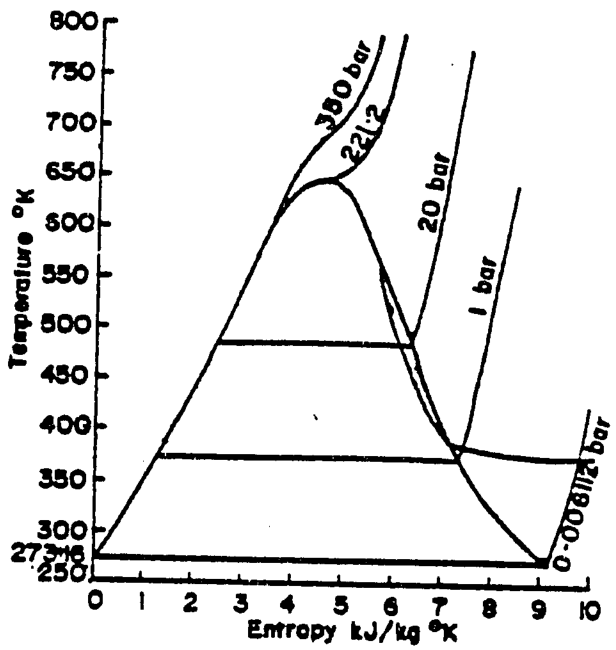

FIG 4· TEMPERATURE-ENTROPY DIAGRAM FOR STEAM

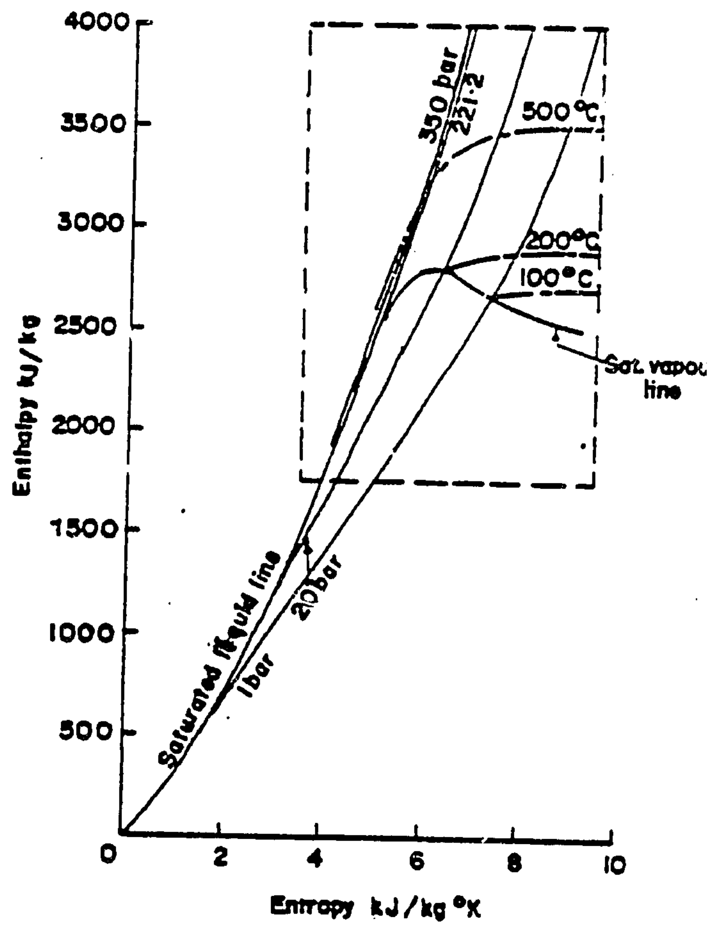

FIG 5· ENTHALPY-ENTROPY DIAGRAM FOR STEAM

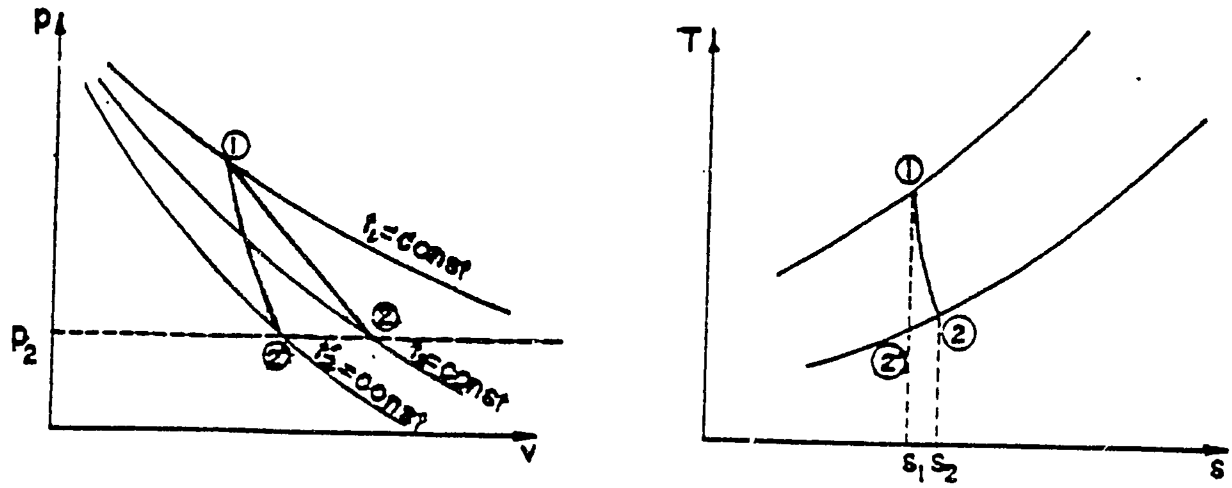

FIG 6· POLYTROPIC & ADIABATIC NON FLOW PROCESSES

TABLE 1

Process Variable	Pressure Constant	Volume Constant	Temperature Constant	Polytropic Reversible	Adiabatic Reversible
PV^n = Const	n=o	n-------	n = 1	n = n	n= —
P,V,T	$\frac{T_2}{T_1} = \frac{V_2}{V_1}$	$\frac{T_2}{T_1} = \frac{P_2}{P_1}$	$P_1V_1 = P_2V_2$	$P_1V_1^n$ = Const	$P_1V_1^\gamma$ = Const
Q (per unit mass)	$C_p(T_2-T_1)$	$C_v(T_2-T_1)$	$RT\ln\left\{\frac{V_2}{V_1}\right\}$	$C_v\ (T_2-T_1)$	0
W (per unit mass)	$P(V_2-V_1)$	0	$RT\ln\left\{\frac{V_2}{V_1}\right\}$	$\frac{P_2V_2 - P_1V_1}{1-n}$	$\frac{P_2V_2 - P_1V_1}{1-\gamma}$
S $(S_2 - S_1)$	$C_p\ln\left\{\frac{T_2}{T_1}\right\}$	$C_v\ln\left\{\frac{T_2}{T_1}\right\}$	$-R\ln\left\{\frac{P_2}{P_1}\right\}$	$\left[C_v + \frac{R}{1-n}\right]\ln\left\{\frac{T_2}{T_1}\right\}$	0

The suffixes (1) and (2) stand for the start and end of the process, respectively. As an example, consider a polytropic process, shown represented on Fig (6). An adiabatic process between the same initial and final pressures has an end point ($2'$) such that the entropy change is zero. For gases, $1 < n < \gamma$ and as a result work done would be less in an adiabatic process than in a polytropic process.

In the case of open systems we can look at actual items of plant and tabulate the various interactions as follows: (see also Fig. 7).

TABLE 2

Process	Boilers and condensers	Turbines	Compressors	Nozzles
Variable				
Q	$(h_2 - h_1) + \frac{1}{2}(c_2^2 - c_1^2)$	0	0	
W	0	$(h_1 - h_2) + \frac{1}{2}(c_1^2 - c_2^2)$	$(h_2 - h_1) + \frac{1}{2}(c_2^2 - c_1^2)$	
η	$\frac{h_2 - h_1}{Q_{in}}$	$\frac{h_1 - h_2}{h_1 - h_{2'}}$	$\frac{h_{2'} - h_1}{h_2 - h_1}$	$\frac{c_2^2}{\{c_2^1\}^2}$

In all these cases, the best or idealised expansion process where maximum external work is done is an adiabatic process. In the real world this is unattainable and all processes are accompanied by a change in entropy. In the case of expansion and compression, irreversibility results in a shortfall in work output and an increase in work input, respectively. Hence we can define an efficiency, called Isentropic efficiency as follows:

where Isentropic Efficiency $= \frac{\text{actual work}}{\text{ideal work}}$ for expansion processes

and Isentropic Efficiency $= \frac{\text{ideal work}}{\text{actual work}}$ for compression processes

Isentropic Efficiency is a measure of the efficiency of a particular component in a cyclic process. It must be distinguished from overall cycle efficiency, which is always ≤ 1 even though individual component isentropic efficiencies may be all equal to 1, in that particular process.

Availability. We are also interested in knowing the maximum possible work available in a given circumstance, even though practical circumstances may prevent us from ever achieving this. By max. available work we might mean expansion to a state o (fig 7) which corresponds to the lowest possible sink temperature To.

Maximum available work can be tabulated as follows:

TABLE 3

Process	Non Flow, reversible adiabatic	General Nonflow	Flow reversible adiabatic	Flow, General
Max. available work $\{W^I\}$	$\{U_1-U_0\}$	$\{U_1-U_0\}$ $-T_0\{S_1-S_0\}$ $-P_0\{V_1-V_0\}$	$\{h_1-h_0\}$	$\{h_1-h_0\}$ $-T_0\{S_1-S_0\}$

Here To is the lowest sink temperature available, P_0 the atmospheric pressure and U, h and v are the internal energy, enthalpy and specific volume respectively. The maximum work is quoted per unit mass of material.

In a general non-flow process, we subtract the work done on the atmosphere in order to obtain nett useful work. This term is not present in flow processes because as much work is done by the atmosphere, as on the atmosphere. It is clearly seen that the second law governs the maximum amount of work available from real processes.

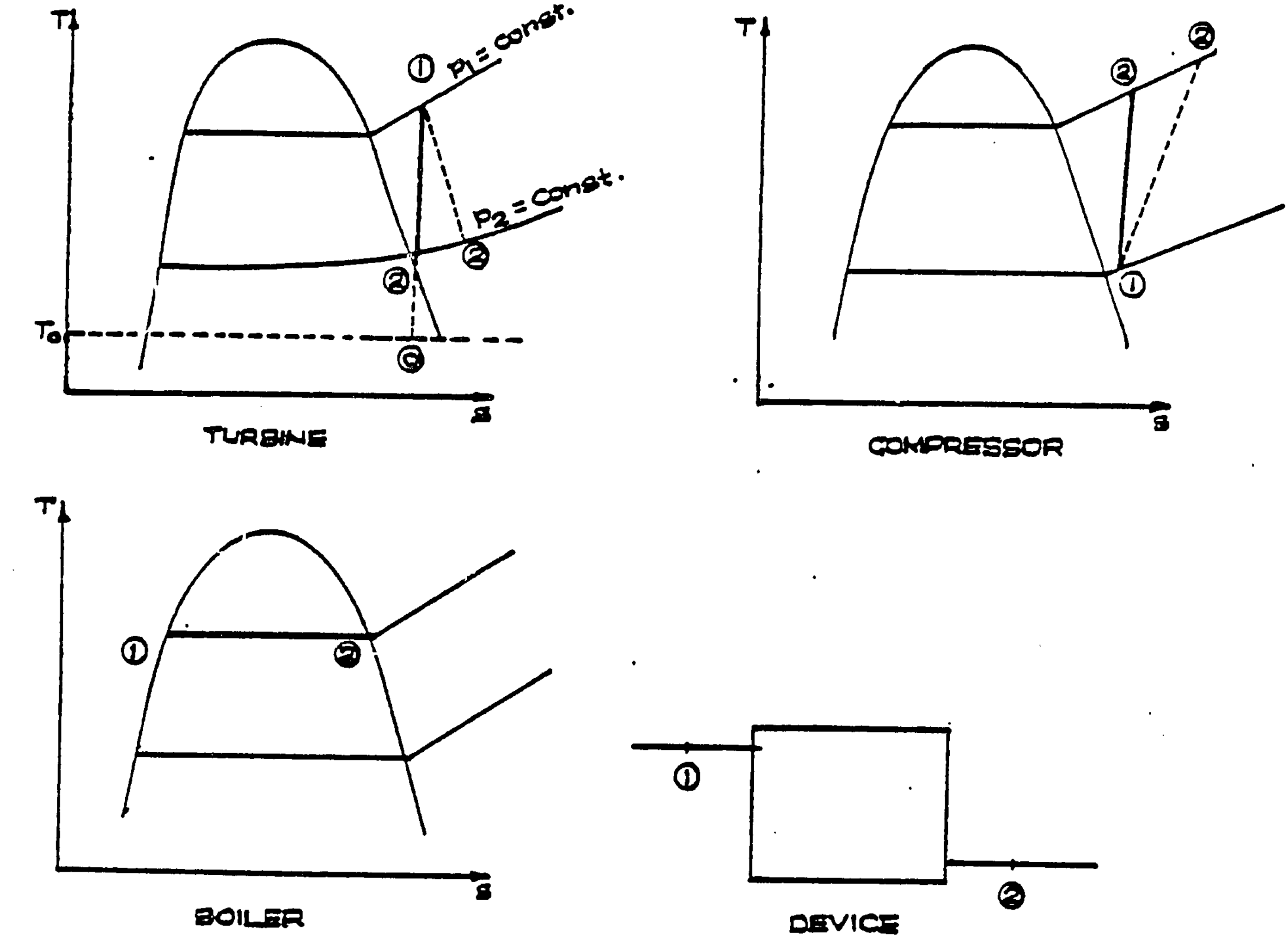

FIG 7 : FLOW PROCESSES

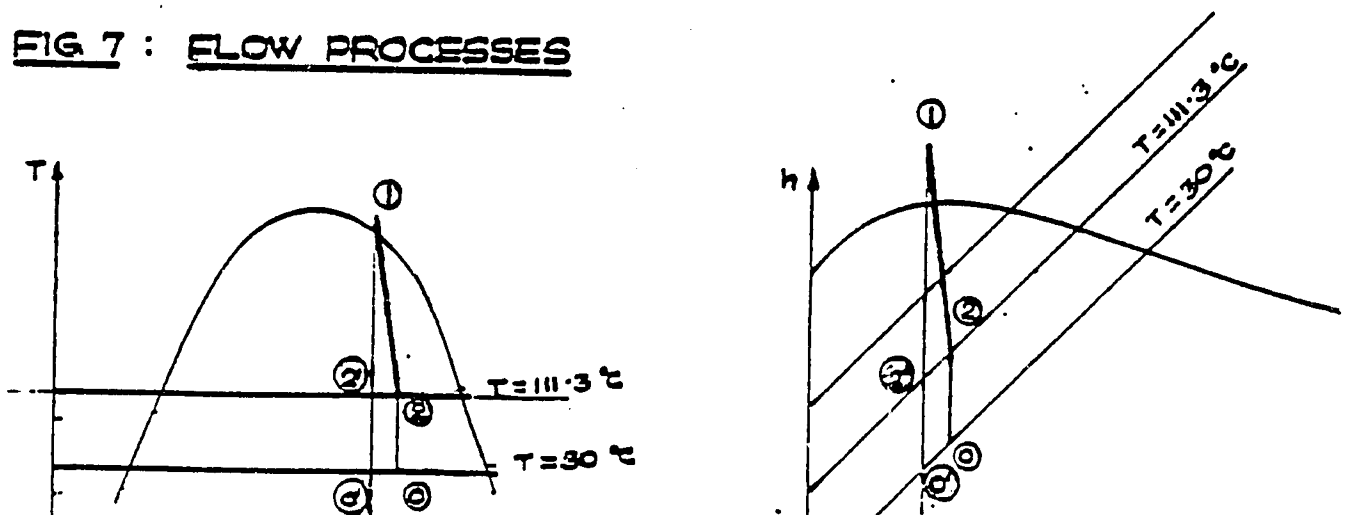

FIG 8 :

A second law efficiency term, more commonly called the effectiveness, can now be defined as

$$E = \frac{W}{W'} \text{ ---------(19)}$$

where W' = max. available work

W = Actual work output from the particular process.

<u>Example</u> : Turbine Work

Turbine inlet conditions	:-	pressure	:-	10 bar
		Temperature	:-	205^0c.
Turbine outlet conditions	:-	pressure	:-	1.5 bar
		Temperature	:-	111.3^0c.

Isentropic efficiency = 95%

Ambient temperature = 30^0c

Find actual work output and maximum available work.

From an ideal adiabatic process, $S_1 = S_2' = 6.7177$.

Process end point is in wet region, Dryness fraction is $0 < x' < 1$

$6.7177 = 1.4336\,(1 - x') + 7.2234\,x'$;

$x'(7.2234 - 1.4336) = 6.7177 - 1.4336$

$x' = 0.912$

$h_2' = 467.1(1 - 0.912) + 2693.4 \cdot 0.922$

$= 2497.48$ KJ/Kg.

Isentropic efficiency $= \dfrac{h_1 - h_2}{h_1 - h_2'} = 0.95$, $h_1 = 2838.9$

$\therefore W = (h_1 - h_2) = 0.95.\ (2838.90 - 2497.48) = 324.35$ KJ/Kg.

Actual dryness will be

$h_2 = 2514.55$

$2514.55 = (1 - x)\ 467.1 + x.2693.4$

$x = 0.9196$

actual entropy is

$S_2 = (1 - x)\ 1.4331 + x.\ 7.2234$

$= 6.7579$

Assume reversible adiabatic expansion to ambient temperature.

$$S_o = S_2 = 6.7578.$$

$$x_o = \frac{6.7579 - 0.4365}{8.4546 - 0.4365}$$

$$= 0.788$$

$$h_o = 125.7\ (1 - 0.788) + 2556.4 \times 0.788$$

$$= 2041.09$$

$$W' = (h_1' - h_0) - T_0\ (S_1 - S_0)$$

$$= (2838.9 - 2041.09) - (273 + 30) \times (6.7177 - 6.7579)$$

$$= 809.99$$

Reversible adiabatic process all the way through,

$$\text{Entropy} = 6.7177$$

$$\therefore\ x = \frac{6.7177 - 0.4365}{8.4541 - 0.4365}$$

$$= 0.7833$$

$$h_0' = (1 - x)\ 125.7 + x\ .2556.4$$

$$= 2029.65$$

$$(h_1 - h_0') = 809.24$$

This proves that whichever way you calculate it, the max. useful work is always the same, and equivalent to that produced by a reversible, adiabatic process between the same initial and final states.

4. Combustion

Analysis of Fuels - A fuel can be analysed in terms of its constituent parts. Analyses are usually quoted in weight of component/unit weight of fuel (or weight of component/Kg mol) in the case of solid and liquid fuels and in terms of volumetric fractions at a particular temperature and pressure, in the case of gaseous fuels.

Example Authracite (coal)

C	H	O	N	H_2O	ash
0.69	0.07	0.04	0.01	0.01	0.13

mass fraction analysis)

Products of combustion - are usually gaseous and generally analysed on a volumetric, dry basis which neglects the water vapour present. The basic (older) instrument of analysis was the Orsat apparatus which progressively absorbs the various chemical constituent gases, enabling measurement of the volume fractions. It is a characteristic of the device that the volume fraction of water vapour is neglected. In the present day, this instrument has been superseded by more sophisticated chemical measuring devices.

The Stoichiometric air fuel ratio is defined as the chemically correct fuel ratio such that all the oxygen present in the air is consumed, together with all the fuel. If a fuel is being burnt under stoichiometric conditions, there will be no unburnt fuel or excess oxygen present in the products of combustion.

$$\text{Stoichiometric A/F ratio} = \frac{\text{mass of air}}{\text{mass of fuel}} \quad \text{----------(20)}$$

Considering chemical reactions, we utilise the law of chemical conservation in equations of the form.

$$C + O_2 \text{ -------} CO_2$$

$$H_2 + \tfrac{1}{2}O_2 \text{ ------} H_2O$$

Considering molecular weights and volumes of substances,

$$\left.\begin{array}{lllllll} 2\ K_g & H_2 & + & 16\ K_g & O_2 & \text{--------}18\ K_g & H_2O \\ 1\ \text{mol} & H_2 & + & \tfrac{1}{2}\ \text{mol} & O_2 & \text{---------}1\ \text{mol} & H_2O \\ 1\ \text{vol} & H_2 & + & \tfrac{1}{2}\ \text{vol} & O_2 & \text{---------}1\ \text{vol} & H_2O\ (\text{vap}) \end{array}\right\} \text{----------(21)}$$

A mass equal to the molecular weight of each substance is defined as a mol. By a chemical rule (Avogadros rule), all gases occupy equal volumes per mol at the same temperature and pressure. Hence volumes can also be equated as shown. If any reactant is in the solid or liquid phase, the volume occupied is neglected ie.

$$C + \tfrac{1}{2}O_2 \text{ -------} CO_2$$

$$0 \text{ vol } C + 1 \text{ vol } O_2 \text{ -------} 1 \text{ vol } CO_2$$

Excess Air - In most practical situations, a certain proportion of excess air is always maintained in combustion, to ensure that all the fuel is consumed. Control of a particular combustion process exactly at stoichiometry is found to be virtually impossible, especially since fuel is wasted if the process slips even a little below stoichiometry (insufficient air condition).

A simple formula for calculating excess air is as follows:-

$$\% \text{ Excess air} = \frac{Z\left\{\frac{N_{pr}}{N_{ra}}\right\}}{0.21 - Z} \quad \text{-----------}(22)$$

where Z = % excess O_2 is the gas or a dry basis.

N_{pr} = Total No. of mols of products/Kg of fuel, in the flue gas, on a dry basis, when the reaction is stoichiometric.

N_{ra} = Total No. of mols of air/Kg of fuel in inlet air stream, when the reaction is stoichiometric.

Or the excess air could be read off from graphs already prepared for the purpose - see Fig. 19.

Example

Analysis of a fuel and products.

Fuel (Hydrocarbon liquid fuel).

C	H	incombustibles
0.857	0.142	0.001

(analysis by weight, per unit weight).

Products

CO_2	N_2	O_2
0.1229	0.8395	0.0376

(analysis by volume, on a dry basis, H_2O in products is neglected).

Find the air fuel ratio under stoichiometric conditions and under the actual conditions given above.

The analysis of inlet air would be as follows:-

O_2	N_2	
21%	79%	(volumetric analysis %)
23.2%	76.7%	(Mass fraction " %)

$\therefore$ The composition of the inlet air stream would be such that for every mol. of O_2 there would be $\frac{79}{21} = 3.76$ mol. of N_2

$$C + (O_2 + 3.76N_2) \text{ ------- } CO_2 + 3.76\,N_2$$

$$H_2 + \tfrac{1}{2}(O_2 + 3.76N_2) \text{ ------- } H_2O + \frac{3.76}{2}N_2$$

$\therefore$ per Kg. of fuel,

$$0.857 + \underset{(\text{Kg } O_2 + N_2)}{\frac{0.857}{12}\left\{32 + 3.76 \times 28\right\}} \text{ ------- } \underset{(\text{Kg } CO_2)}{\frac{44}{12} \times 0.857} + \underset{(\text{Kg } N_2)}{3.76 \times \frac{28}{12} \times 0.857}$$

$$\underset{(\text{Kg H})}{0.142} + \underset{(\text{Kg } O_2 + N_2)}{\frac{1}{4} \times 0.142\,(32 + 3.76 \times 28)}$$

$$\text{-------} \frac{18}{2} \times 0.142 \;(\text{Kg } H_2O)$$

$$+ \frac{3.76}{4} \times 28 \times 0.142 \;(\text{Kg } N_2)$$

$\therefore$ per Kg of fuel, mass of air required $= \frac{0.857}{12}(32+3.76 \times 28)$

$+ \frac{0.142}{4}(32 + 3.76 \times 28)$

$= 14.67$

$\therefore$ stoichiometric A/F ratio $= \frac{14.67}{1} = \underline{\underline{14.67}}$

Actual excess air on a dry basis = 3.74 %

Hence from the chart, % excess air = 20%

ie. there is 20% excess air, by volume, in the inlet air stream. Hence there are 20% mols. of air per Kg of fuel.

$\therefore$ Actual air moles per Kg fuel $= \left\{\frac{0.857}{12} + \frac{0.142}{4}\right\}$

$\times (32 + 3.76 \times 28) \times 1.2$

$= 17.65$

$\therefore$ Actual A/F ratio $= \frac{17.65}{1} = \underline{\underline{17.65}}$

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Chemical Reaction. Consider a set of Reactants which chemically react under constant volume conditions, to give a set of products, as shown in Fig. 9 The initial and final volume and temperature are different, but the actual chemical reaction is considered to take place at a reference temperature and volume given by $\{V_0 \quad T_0\}$.

Applying the 1st law to the system.

$$Q = \{U_{P2} - U_{R1}\}$$

where U_{P2} = internal energy of product/unit mass

U_{R1} " " " reactions/unit mass

$$\therefore Q = \{U_{P2} - U_{PO}\} + \{U_{PO} - U_{RO}\} + \{U_{RO} - U_{R1}\} \quad \text{----------(23)}$$

Then $(U_{pO} - U_{RO}) = U_O$, which is the heat released under conditions of constant volume and constant temperature. This is called the internal energy of combustion.

Similarly, for an open system (or flow process)

$$Q = (H_{P2} - H_{R1})$$

$$= (H_{P2} - H_{PO}) + (H_{PO} - H_{RO}) + (H_{RO} - H_{R1}) \quad \text{-------(24)}$$

$$\text{where } (H_{PO} - H_{PO}) = \sum m_i \; C_{pi} \; (T_2 - T_O) \quad \text{-----------(25)}$$

$$(H_{RO} - H_{R1}) = \sum m_i \; C_{pi} \; (T_O - T_1) \quad \text{-----------(26)}$$

T_O is the reference temperature at which enthalpies of combustion are usually evaluated.

It is to be noted that enthalpies in chemical reaction are usually quoted in tables as enthalpies of formation, which is the heat absorbed or rejected when a compound is formed from its basic elements.

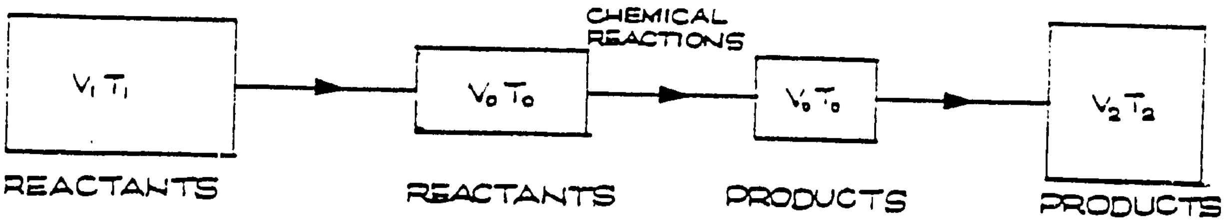
e.g. $C + O_2$ ------- CO_2 , $(\Delta H_g)_{25} = -393513$ KJ/Kg mol.

The enthalpies of element such as H_2, O_2 etc. are taken as 0. Enthalpies of formation are usually found by measuring the heat rejected during a steady flow combustion process, carried out in such a way that

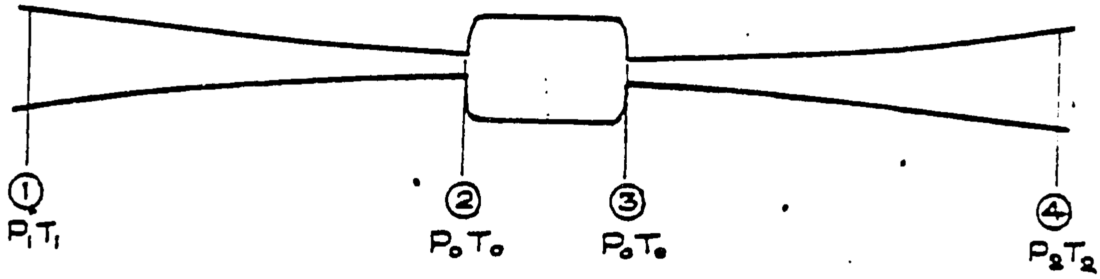
a) Reactions and Products are both at T_O and P_O (usually 25^{oC} and 1 atm. pressure).

b) No external work is done.

c) Change in KE and PE is negligible.

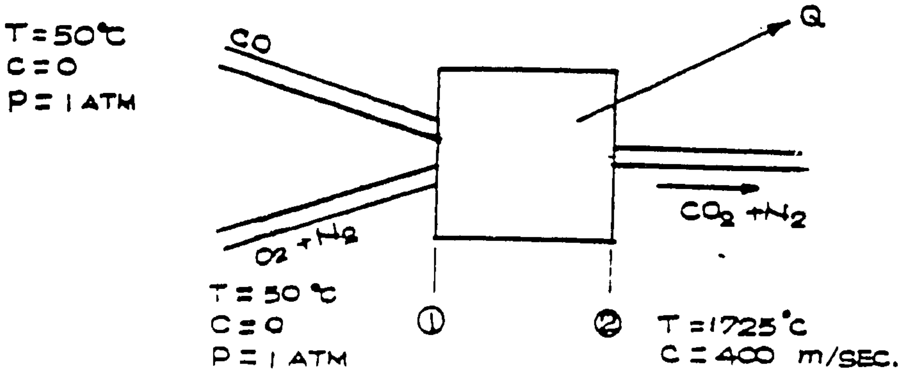


CHEMICAL REACTION, CONSTANT VOLUME



CHEMICAL REACTION, CONSTANT PRESSURE

FIG 9:



FLOW OF CO = 1 mol/minute

FIG 10:

In the actual combustion of a fuel, enthalpies of formation are used as follows:-

$$(sy)\ CH_4 + 2O_2 \text{ ------- } CO_2 + 2H_2O$$

This can be regarded as -

$$CH_4 + 2O_2 \xrightarrow{(1)} C + 2H_2 + 2O_2$$

$$C + 2H_2 + 2O_2 \xrightarrow{(2)} CO_2 + 2H_2O$$

For (1), $Q_1 = (\Delta H)_C + 2(\Delta H)_{O_2} + 2(\Delta H)_{H_2} - (\Delta H)_{CH_4} - 2(\Delta H)_{O_2}$

For (2), $Q_2 = (\Delta H)_{CO_2} + 2(\Delta H)_{H_2O} - \{(\Delta H)_C + 2(\Delta H)_{O_2} + 2(\Delta H)_{H2}\}$

Total heat released

$$Q = Q_1 + Q_2 = (\Delta H)_{CO2} + 2(\Delta H)_{H_2O} - (\Delta H)\ CH_4 \text{ --------(27)}$$

Hence the principle is that heat released in a reaction is given by -

Q = (Enthalpy of formation of products)-(Enthalopy of formation of reactants).

= Enthalpy of combustion for the particular fuel.

Note also that when enthalpies are (-)ve heat is released in the reaction and when (+ ve) heat is absorbed in the reaction.

Examples

A Combustion chamber (see Fig.10)

by the first law

$$Q - W = (H_{P2} - H_{R1}) + \frac{\dot{M}_2 C_2^2}{2} - \frac{\dot{M}_{CO} C_{CO}^2}{2} - \frac{\dot{M}_{O_2} M_{O_2}^2}{2} \text{ ---------(28)}$$

Chemical equation.

$$CO + \tfrac{1}{2}(O_2 + 3.75\ N_2) \text{ -------} CO_2 + \frac{3.76}{2} N_2$$

$$H'P_2 = (\Delta H)_{CO_2} + 1.(1725 - 25)Cp_{CO_2} + \tfrac{1}{2}.\ 3.76.\ Cp_{N_2}.(1725 - 25)$$

$$= -(393513 + 27.12\ (1725 - 25) + \frac{3.76}{2} \times 29.12\ (1725-25)$$

$$= -254341.7 \text{ KJ/minute}$$

$$H'R1 = (\Delta H)_{CO} + Cp_{CO}\ (25 - 50) + \{(\Delta H)_{O_2} + Cp_{O_2}\ (25 - 50)\}\ \tfrac{1}{2}$$

$$+ ((\Delta H N_2) + 3.76\ Cp_{N_2}\ (25.50))\tfrac{1}{2}$$

$$= -110523 + 29.142\ (25 - 50) + \frac{29.359}{2}\ (25-50) + \frac{29.121}{2}\ 3.76\ (25-50)$$

$$= -112987.2 \text{ KJ/minute}$$

$$M_2 = 1\ (44 + \frac{3.76}{2} \times 28) = 96.64 \text{ Kg/minute}$$

$$= \frac{M_2\ C_2^{\ 2}}{2} = 7731.2 \text{ KJ/minute}$$

$$\therefore Q = -237324.5 - (-112987.2) + 7751.2$$

$$= 254341.4 \text{ KJ/minute}$$

$$= \underline{2227 \text{ KW}}$$

Calorific values

Gross calorific value	-	Enthalpy of combustion with H_2O in the products, in a liquid state.
Nett calorific value	-	Enthalpy of combustion with H_2O in the products in a vapour state.

Nett calorific value < gross calorific value. Nett calorific value is preferred in efficiency calculations because (a) Condencation of water vapour in production is not practical because corrosion problem could arise. (b) 2nd Law analyses of combustion chambers also show that the max. useful energy available is closer to the nett value rather than the gross value.

5. Heat and Mass Transfer

In heat transfer, we consider three fundamental phenomena ie. Conduction, Convection and Radiation.

Conduction is heat transfer from one molecule to another in any material, without bulk measurement of the fluid.

The mechanism is governed by Fouriers Law ie. that

Rate of heat transfer temperature gradient

ie. $q \propto \frac{T}{X}$

or $$q = -K\ A\ \frac{dT}{dx} \qquad (29)$$

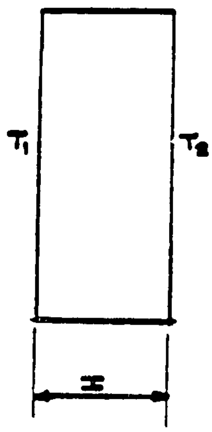
A is the cross sectional area where heat transfer takes place and K is a physical property of the material known as thermal conductivity. Note that the - sign is used because the direction of heat flow is opposite to the direction of increasing temperature gradient.

The units of K in the S.I. system are

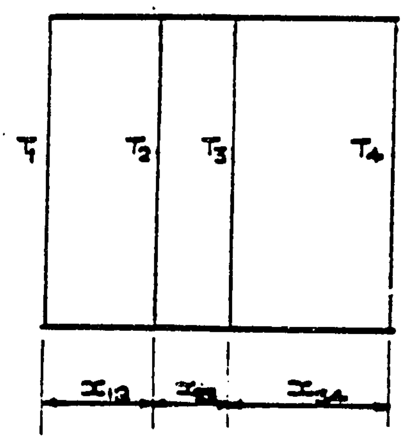
$$\frac{W}{m \quad {}^{o}K/m} = \frac{W}{m\ {}^{o}K}$$

In the imperial (British) system, the units are

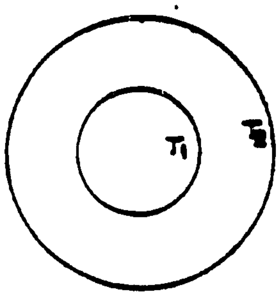
$$\frac{BTU}{\text{hour sq. ft. deg F/perfoot}} = \frac{BTU}{\text{hr. ft. deg F}}$$



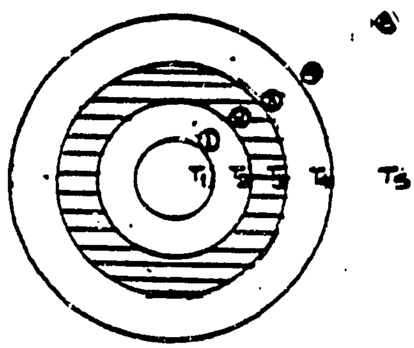
WALL



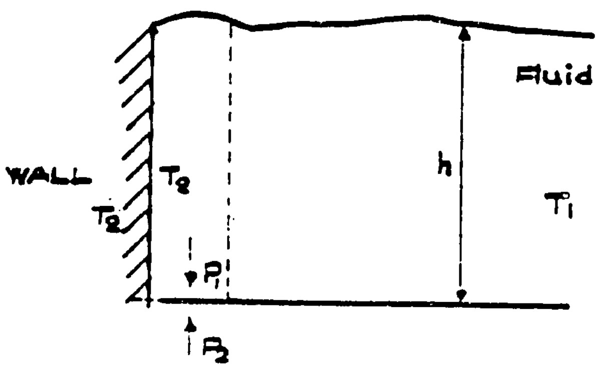
COMPOSITE WALL



TUBE



COMPOSITE TUBE



$T_2 > T_1 \qquad \rho_2 < \rho_1$

$\therefore \rho_2 g H < \rho_1 g H$

$\therefore \quad P_2 < P_1$

FIG 11:

Conversion factors are given in the table attached. For steady heat flow across a wall, (fig. 11)

$$Q = \frac{- KA\ (T_2 - T_1)}{x} \text{ ------- } (30)$$

where x = thickness of the wall.

For a composite wall,

$$Q = A.U.\ (T_4 - T_1) \text{ ------- } (31)$$

where
$$U_1 = \frac{1}{\frac{x_{12}}{K_{12}} + \frac{x_{23}}{K_{23}} + \frac{x_{34}}{K_{34}}} \text{ ------- } (32)$$

U_1 is the overall heat flow coefficient, with units $\frac{W}{m^2\ {}^oK}$

For a tube
$$\frac{- 2\pi K \{T_2 - T_1\} L}{Ln \left\{\frac{r_2}{r_1}\right\}} \text{ ------- } (33)$$

and for a composite tube,

$$Q = - 2\pi L(T_4 - T_1).U_2 \text{ ------- } (34)$$

where U_2
$$\frac{1}{\frac{Ln \left\{\frac{r_2}{r_1}\right\}}{K_{12}} + \frac{Ln \left\{\frac{r_3}{r_2}\right\}}{K_{23}} + \frac{Ln \left\{\frac{r_4}{r_3}\right\}}{K_{34}}} \text{ ------ } (35)$$

When U_2 = heat transfer coefficient per unit length of tube

The units of this coefficient would be $\frac{W}{m\ {}^oK}$, ie. different to U_1

Convection can be broadly defined as heat transfer due to actual physical translation of molecules from point to point.

Natural Convection takes place due to buoyancy differences caused by temperature differences in a liquid or gas.

Forced convection occurs when movement of fluid takes place due to externally applied pressure differences.

In convective heat transfer, as in conduction, we would like to describe the phenomena by a relationship of the form.

$$Q = HA\ (T_1 - T_2)$$

When H is the Heat Transfer Coefficient. However, in convective flow, there are many more variables and simple analytical solutions cannot be found. The Heat transfer coefficient is found to be a function of

Viscosity	μ
Density	ρ
Thermal Conductivity	K
Specific Heat	Cp
Fluid Velocity	C
Characteristic Dimension	D

In the S.I. system, the units of Heat Transfer coefficients are usually $\frac{W}{m^2\ {}^oK}$. By dimensional analysis, it is found that convective heat transfer is best characterised by three non-dimensional parameters.

$$Nu = \left\{\frac{HD}{K}\right\}, \quad Re = \left\{\frac{\rho CD}{\mu}\right\}. \quad Pr = \left\{\frac{C_p\,\mu}{K}\right\}$$

Nusselt No   Reynolds No   Prandtl No

and in most forced convection heat transfer situations, we can say,

$$\therefore \frac{HD}{K} = s.\left\{\frac{CD\rho}{\mu}\right\}^a \bullet \left\{\frac{C_p\,\mu}{K}\right\}^b \text{ ---------- } (36)$$

ie. $Nu = S.\ (Re)^a.\ (Pr)^a$ when S, b and c are empirically determined coefficients.

e.g. Fluid Flow within tubes or pipes, (Reference 4,

$$Nu = 0.023\ (Re)^{0.8}\ (Pr)^{0.4} \text{ ---------- } (37)$$

Heating and cooling outside tubes, in the case of a bank of tubes.

$$Nu = 0.33\ (Re)^{0.6}\ Pr^{0.333} \text{ ---------- } (38)$$

Hence given the material properties of the fluid and the dimensions of a particular piece of equipment, we can obtain the governing heat transfer coefficient H. Values of a, b and s other than the above can be obtained from the literature in different circumstances.

<u>In Natural Convection</u> localised heating of a fluid will cause the density to become smaller. Hence a pressure difference will be set up due to the rest of the fluid being at a lower temperature, and circulation of fluid will take place (see Fig. 11).

As in forced convection, there are a large number of variables in forced convection too. Hence a No. of non-dimensional variables are utilised in the analysis. Reynolds No. is replaced by an analogous term know as Grashof No. (Gr), where

$$Gr = \frac{\beta g \rho^2 x^3 (T - T_b)}{\mu^2} \quad \text{----------} (39)$$

when β = coefficient of cubical expansion

x = height above bottom of heated wall.

$(T - T_b)$ = Temperature difference between heated fluid and bulk fluid. Grashof number comes in because there is no externally imposed bulk velocity C, in natural convective flow. Fluid velocity is itself a function of the heating effects.

Again, heat transfer coefficients are found from a relationship of the form.

$$N_u = S\ (Gr)^a\ (Pr)^b \quad \text{---------} (40)$$

Some simplified formulae for Natural convection in air are as follows: (from Reference 2)

TABLE 3

ℓ, d in m	average h $W/m^2\ {}^oK$	
	laminar or transition	turbulent
Vertical plate, or cylinder of large diameter, or height ℓ	$10^4 < Gr < 20^9$ $1.42(\theta/\ell)^{1/4}$	$10^9 < Gr < 10^{12}$ $1.31\theta^{1/3}$
Horizontal cylinder of diameter d	$10^4 < Gr < 10^9$ $1.32(\theta/d)^{1/4}$	$10^9 < Gr < 10^{12}$ $1.25\theta^{1/3}$
Square plate $\ell \times \ell$: heated plate facing up or cooled plate facing down	$10^5 < Gr < 2 \times 10^7$ $1.32(\theta/\ell)^{1/4}$	$2\times10^7 < Gr < 3\times10^{10}$ $1.52\theta^{1/3}$
Square plate $\ell \times \ell$; cooled plate facing up or heated plate facing down	$3\times10^5 < Gr < 3\times10^{10}$ $0.59(\theta/\ell)^{1/4}$	

Where $\theta = (T - T_b)$, Temp. difference between wall and bulk fluid.

These formulae have been obtained empirically.

Radiation is heat transfer by means of electromagnetic phenomena. The law governing heat flow in relation to temperature is the stefan - Boltzmann Law.

$$\dot{q}_b = \sigma T^4 \quad \text{----------} (41)$$

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Where $\sigma = 56.7 \times 10^{-12} \frac{KW}{m^2\ ^oK}$, the Stefan-Boltzmann constant.

This form of the equation applies strictly only to a so called "Black body", which absorbs all radiation impinging on it. In the case of a real material,

$$\dot{q}_b = \sigma E T^4 \quad \text{-------}(42)$$

where E is the emissivity of the material and $o < E < 1$. Another rule states for radiation of a fixed wave-length, the emissivity is equal to a property called the absorptivity ie. the capacity of the surface to absorb incident radiation.

Every single body and substance radiates heat away from it at a rate determined by its surface temperature and coefficient of emmissivity. Hence a hot body which is radiating energy is also receiving radiant energy from all the surrounding objects. Hence radiation heat transfer is really the nett exchange of energy between the body of interest and its surroundings.

$\therefore$ The nett energy exchange is given by an equation of the form

$$\dot{q} = Fe \ (T_1^4 - T_2^4) \quad \text{-------}(43)$$

Where Fe is an emmissivity and area factor which accounts for differences between bodies and their surroundings. Fe can be tabulated as follows: (Reference 2).

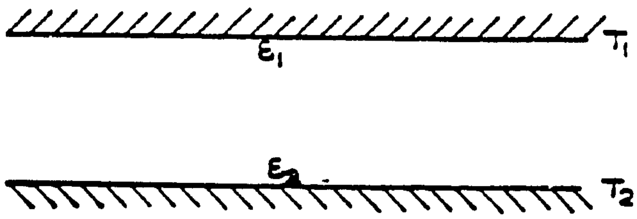
TABLE 4

Body (Fig. 12).	Factor (Fe)
Infinite parallel plate	$\dfrac{1}{\frac{1}{E_1} + \frac{1}{E_2} - 1}$
Completely enclosed small body (small body at higher temperature)	E_1
Completely enclosed large body (large body at higher temperature)	$\dfrac{1}{\frac{1}{E_1} + \frac{1}{E_2} - 1}$
Concentric Cylinder or sphere (outer body at higher temperature)	$\dfrac{A_1/A_2}{\frac{1}{E_1} + \frac{1}{E_2} - 1}$
Concentric cylinder or sphere (inner body at higher temperature)	$\dfrac{1}{\frac{1}{E} + \frac{1}{E_2} - 1}$

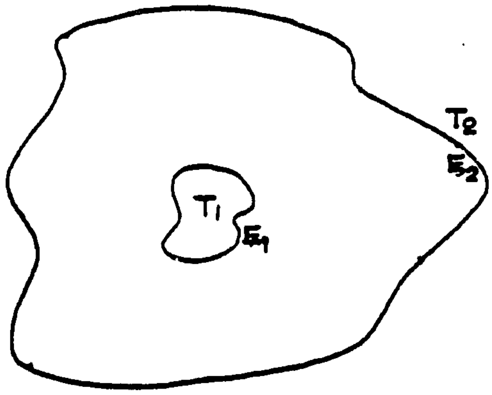
The heat transfer rate from any of the above-mentioned bodies will be given by

$$Q = A \cdot Fe \cdot (T_1^4 - T_2^4) \quad \text{---------} \ (44\ A)$$

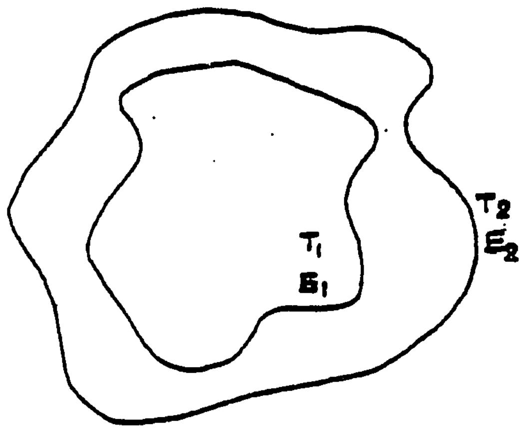
where A is the area of the body whose temperature is T_1



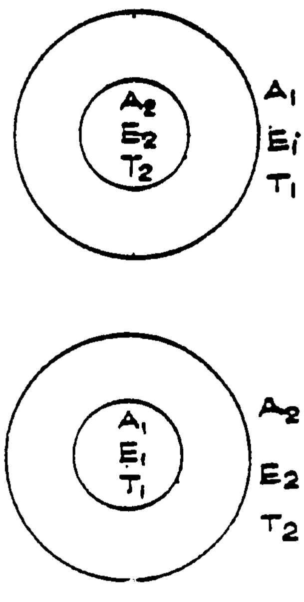
INFINITE PARALLEL PLATE



COMPLETELY ENCLOSED SMALL BODY



COMPLETELY ENCLOSED LARGE BODY



CONCENTRIC CYLINDER OR SPHERE

FIG 12:

NOTE : All temperatures in radiative heat transfer are in $^{\circ}K$ = (273 + $^{\circ}C$)

From (44A)

$$Q = A\ Fe\ (T_1^{\ 2} + T_2^{\ 2})\ (T_1^{\ 2} - T_2^{\ 2})$$

$$= A\ .\ H\ (T_1 - T_2) \text{ ------- } (44B)$$

where $H = Fe(T_1^{\ 2} + T_2^{\ 2})\ (T_1 + T_2)$

and H is a Heat Transfer coefficient analogous to the coefficients defined in the case of conductive and convective heat trsnfer.

Applications

1. **Heat Transfer from a Pipe**

Consider a pipe with a fluid flowing within it and insulated with a suitable material. The cross-sectional configuration would be as shown in Fig. 11.

Then the heat transfer coefficients would be as follows:

H_{1-2} --------- Convection flow

$$\text{---------}\ \frac{K}{d}\ S\ (Re)^a\ (Pr)^b$$

$$\left.\begin{array}{ll} H_{2-3} & \text{--------- Conduction} \\ H_{3-4} & \text{---------}\quad '' \end{array}\right\} - H_{2-4}$$

$$H_{2-4} \text{ ------ } \frac{1}{\dfrac{Ln\left\{\dfrac{r_3}{r_2}\right\}}{K_{23}} + \dfrac{Ln\left\{\dfrac{r_4}{r_3}\right\}}{K_{34}}}$$

H_{4-5} - By combined natural convection and radiation

$$\text{-------}\left\{\frac{K}{d}\right\} C\ (Re)^a\ (Pr)^b + Fe\ (T_4^{\ 2} + T_5^{\ 2})\ (T_4 + T_5)$$

∴ Overall heat transfer coefficient is H_{1-5}

Such that $$\frac{1}{H_{1-5}} = \frac{1}{2\pi r_1\ H_{1-2}} + \frac{1}{H_{2-4}} + \frac{1}{2\pi r_4\ H_{4-5}}$$

(The $2\pi r$ terms are required in the case of H_{1-2} and H_{4-5} because because these are in terms of Heat transfer per unit area, whereas H_{1-5} and H_{2-4} are in terms of heat transfer per unit length of tube)

2. Simple Heat Exchanger

See Fig. 13. It can be shown that

$$Q = HA \frac{\Delta T_o - \Delta T_i}{Ln \left\{ \frac{\Delta T_o}{\Delta T_i} \right\}} \text{---------} \quad (45)$$

$$= HA \, \Delta T_m$$

When T_m = mean temperature difference between the fluids

$$T_m = \frac{\Delta To - \Delta Ti}{Ln \left\{ \frac{\Delta T_o}{\Delta T_i} \right\}} \text{----------} \quad (46)$$

Here H is an overall heat transfer coefficient, again of the form

$$\frac{1}{H} = \frac{1}{H_1} + \frac{1}{H_2} + \frac{1}{H_3}$$

As in case (1) previously governing equations in more complicated cases can be found in the literature (e.g. reference 4).

Mass Transfer

As in the case of heat transfer, mass transfer phenomena can also be represented as follows:

$$N \quad (C_1 - C_2) \text{--------} \quad (47)$$

When N is the mass transfer rate, $(C_1 - C_2)$ is the difference in a property. Unlike heat transfer, there is no fixed property such as temperature which difference uniquely controls mass transfer. Instead, mass transfer rates can be related to three different properties and their differences, ie.

Differences in concentration of substances

" " partial pressures

" " Humidities

Concentration is defined as mols of substance/unit volume of mixtures.

Humidity is defined as $\dfrac{\text{Kg of substance}}{\text{Kg of carrying medium (mass air)}}$

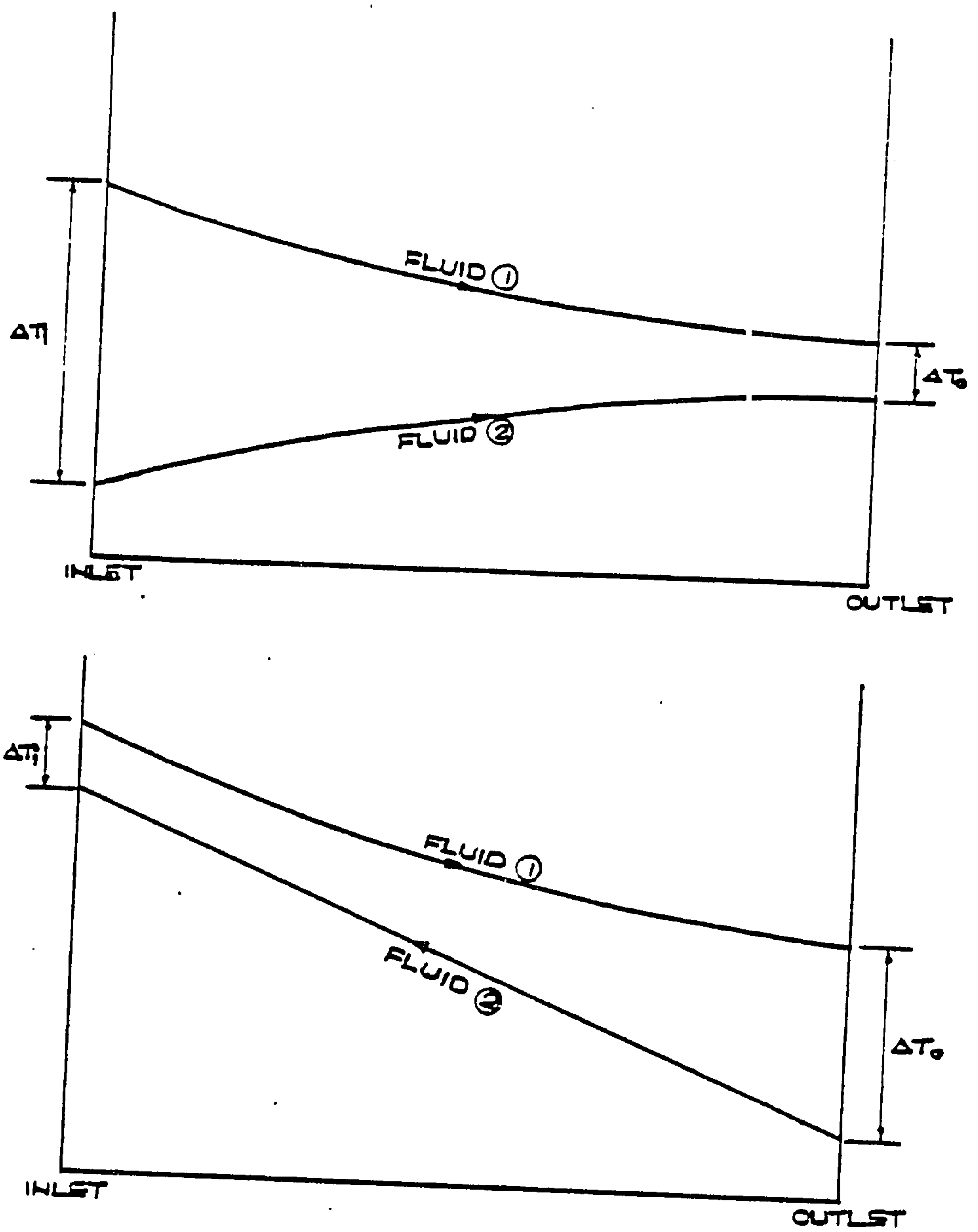


FIG 13A : HEAT EXCHANGER

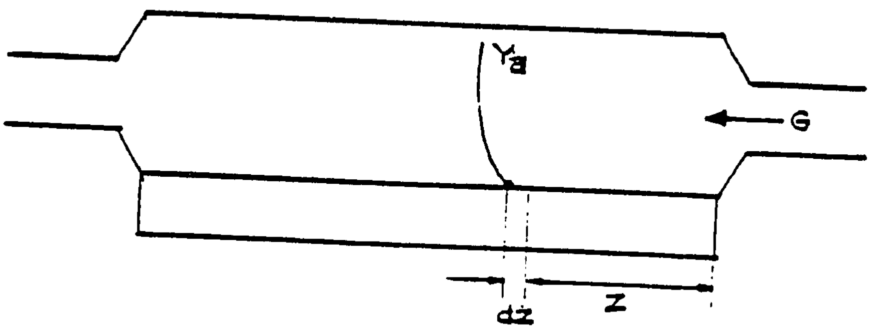


FIG 13B : BATCH DRYER

Applications

Consider a batch type dryer shown represented in Fig. 13B. The rate of humidification of the air is equal to the moisture transfer rate from the material being dried.

$$\text{Hence, } N_a = K'.\ A.\ (C_i - C_2) \text{ --------- } (49)$$

When K' is the mass transfer coefficient, which is exactly analogous to a heat transfer coefficient.

Also for the flow,

$$Gdy = K'\ d\ z.\ a\ (Y_s - Y_a)$$

and solving,

$$Na = Na_o \ \exp - \left\{ \frac{K'aZ}{G} \right\} \text{ -------- } (50)$$

When $Na \propto (Y_s - Y_a)$

$Na_o \propto (Y_s - Y_a)_O$ ie. conditions at inlet to dryer (see reference 2)

Equation shows that the mass transfer rate varies exponentially from inlet to outlet in the dryer. Similar though more complex relationships are available in the literature for continuous drying processes etc. Coefficients such as K are obtained from correlations which are similar to those concerning heat transfer.

$$\frac{K'L}{D} = 0.33 \ \ln \left\{ \frac{1+B}{B} \right\} (Re)^{0.72} \left\{ \frac{Cm\,\mu}{Km} \right\}^{0.33}$$

When

$\frac{K'L}{D}$ ---------- $\left\{ \frac{hl}{K} \right\}$.

Sherwood No — Nusselt No

$\frac{Cm\,\mu}{Km}$ ----- $\frac{C_p\,\mu}{K}$

Schmidt No — Prandtl No

$C_p = \frac{\Delta H}{\Delta T}$ $\quad$ $C_m = \frac{\Delta X}{\Delta W}$

Cm is generally known as the mass capacity of a body and is similar to C_p which is the heat capacity of a body or substance. Cm measures the ability of the body or substance to absorb/retain water or other liquids.

In the S.I. system, the unit of the mass transfer coefficient K' would be as follows:

Concentration difference	-	$\frac{m}{s}$
Partial pressure differences	-	$\frac{Kg}{NS}$
Humidity differences	-	$\frac{Kg}{M^2 s}$

6. Analysis of a Boiler

In this case study, we analyse a set of typical data that would be the result of an experimental study of a boiler. We also investigate the effects of changes in excess oxygen level and flue gas temperature, on boiler efficiency.

Date

Fuel Analysis

C	H	S	
86.1%	11.8%	2.1%	(by weight)

Product Analysis

Excess O_2 in Stack	————	2%
Stack temperature	————	$400^\circ C$
Ambient temperature	————	$30^\circ C$
Mass flow rate of fuel	————	0.095 Kg/second
(Lower) Calorific Value of fuel	————	42,900 KJ/Kg
Specific heat of fuel	————	1.98 KJ/Kg °K
Boiler wall area (Total)	————	2000 Sq.feet
Boiler external temperature	————	80°C
Boiler output at full capacity	————	10,000 lbs/hour at 10 bar, Dry Sat.
Boiler Blowdown	————	1% of mass flow (average).

Governing Chemical Equations for the reaction.

$$C + (O_2 + 3.76\,N_2) \longrightarrow CO_2 + 3.76\,N_2$$

$$H + \tfrac{1}{4}(O_2 + 3.76\,N_2) \longrightarrow H_2O + 3.76\,N_2$$

$$S + (O_2 + 3.76\,N_2) \longrightarrow SO_2 + 3.76\,N_2$$

Then, per Kg of fuel,

$$\underset{(Kg\ C)}{0.868} + \underset{(Kg\ O_2 + N_2)}{\frac{0.868}{12}(32 + 3.76 \times 28)} \text{ ---- } \underset{(Kg\ C)}{\frac{44}{12} \times 0.868} + \underset{(Kg\ N_2)}{\frac{3.76 \times 0.868}{12} \times 28}$$

$$\underset{(kg\ H)}{0.118} + \underset{(Kg\ O_2 + N_2)}{\frac{0.118}{4}(32 + 3.76 \times 28)} \text{ ---- } \underset{(Kg\ H_2O)}{\frac{0.118 \times 18}{4}} + \underset{(Kg\ N_2)}{\frac{3.76 \times 28}{2 \times 2}} \text{ ----- } (51)$$

$$\underset{(Kg\ S)}{0.021} + \underset{(Kg\ O_2 + N_2)}{\frac{0.021}{32}(32 + 3.76 \times 28)} \text{ -- } \underset{(KG\ SO_2)}{\frac{0.021}{32} \times 64} + \underset{(Kg\ N_2)}{\frac{3.76 \times 0.021}{2 \times 32}} \text{ ---- } (52)$$

Let the amount of excess air in inlet air stream be Z in terms of volume fraction. No. of Kg mols. of O_2 in inlet air stream, per Kg. of fuel, at stoichiometry,

$$= \left\{\frac{0.868}{12} + \frac{0.118}{4} + \frac{0.021}{32}\right\}$$

$$= 0.1024$$

$\therefore$ No. of mols. of O_2 in product stream, with Z excess air

$$= 0.1024 \times Z$$

$\therefore$ No. of mols. of N_2 in product stream with Z excess air

$$= 0.1024 \times 3.76 \times (1 + Z)$$

Hence we can tabulate the No. of Kg. mols. of reactants and products per kg. of fuel, and the specific heats as follows:

TABLE 5

Substance	Kg.mols / kg.fuel	Specific Heat
Fuel	----	1.98 KJ/Kg oK
inlet O_2	0.1024 (1+Z)	29.35 KJ/Kg mole oK
inlet N_2	0.385 (1+Z)	29.12 " "
Product CO_2	0.07232	37.12 " "
Product H_2O	0.0295	33.571 " "
Product O_2	0.1024Z	as above
Product O_2	0.385 (1+Z)	as above
Product SO_2	0.00065	

(Since the amount of SO_2 is small, we neglect it in all subsequent calculations.

By the 1st Law, per Kg. of fuel (t = stack temperature, Z = fraction of excess air per volume).

$$Q - W = (H_{prt} - H_{R30}) + \left\{\begin{matrix}\Delta KE \\ terms\end{matrix}\right\} + \left\{\begin{matrix}\Delta PE \\ terms\end{matrix}\right\}$$

$$\{H_{prt} - H_{R30}\} = \{H_{prt} - H_{pr\,25}\} + \{\Delta H_{25}\}\ fuel + \{H_{R25} - H_{R30}\}$$

$$\{H_{R25} - H_{R30}\} = (25-30) \sum m_1\, C_{pi}$$

$$= (-5)\ (0.1024\ (1+Z) \times 29.35 + 0.385\ (1-Z) \times 29.12 + 1 \times 1.9$$

$$= (-5)\ (14.21\ (1+Z) + 1.98)$$

$$\{H_{prt} - H_{pr25}\} = (t-25)\ (0.07233 \times 37.57 - 0.0295 \times 33.75 + 0.385\ (1+Z$$

$$\times 29.12 + 0.1024\,Z \times 29.35)$$

$= (t-25)\ (14.92 \ + 14.21\ Z)$

$(\triangle H_{25})_{fuel} = -42{,}900$ KJ/Kg

$\therefore\ Q \quad = -42{,}900 + (t-25)\quad(14.92 + 14.21\ Z) \quad -5\ (14.21(1+Z) + 1.98)$

$$\underline{Q = -43353.9 + t\ (14.918 + 14.21Z) \ - 426\ Z} \quad \text{-------} \quad (53)$$

Hence for the given conditions of t $= 400^{\circ}C$,

Excess O_2 $= 2\%$

$\therefore$ Z $= (10\%) = 0.1$ from fig. 19.

$\therefore$ Q· = 36860.9 KJ/Kg fuel and for a fuel flow of 0.095 Kg/second,

Q = 3501 KJ/second

= <u>3501</u> Kw of heat

<u>And Indirect (Combustion) efficiency</u> $= \dfrac{3501}{42{,}900 \times 0.095} \times 100$

$= \underline{85.9\%}$

<u>Considering steam flow conditions</u>

10,000 lbs/hour (4545 Kg/hour) at 10 bar.

$\therefore$ From the steam tables, dry saturated temperature at 10 bar is $185^{\circ}C$

Also, change in Enthalpy is given by

$(\triangle H)$ Steam $= 2012.6 + 4.2\ (180-130)$

$= 2643.6$ KJ/Kg steam.

$\therefore$ For the process,

$(\triangle H)$ steam $= 2643.6 \times \dfrac{4545}{3600}$

$= 3337.5$ KW

$\therefore$ Overall Efficiency $= \dfrac{\text{Enthalpy increase of steam}}{\text{Calorific value of fuel}}$

$= \dfrac{3337.5}{42{,}900 \times 0.095} \times 100$

$\therefore$ <u>Overall Efficiency</u> $= \underline{\underline{82\%}}$

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Considering Heat Transfer losses.

Convection heat transfer coefficient from exposed areas of boiler

$$= 1.31\,(80-30)^{\frac{1}{3}}$$

from equation in Table 3 $= 4.82\ w/m^2\ {}^oK$

Radiation Heat Transfer from exposed areas of boiler using equation 44 B, p.21

$$= 56.7 \times 10^{-9}\,\left((273+80)^2 + (273+30)^2\right) \times (273 + 80 + 273 + 30)$$

$$= 8.05\ w/m^2\ {}^oK$$

$\therefore$ overall losses from boiler $= H.A.\left[T(\text{boiler}) - T(\text{ambient})\right]$

$= 12.85 \times (2000 \times 0.30^2) \times (80-30)$

$= 119047.5$

$=$ 119. KW

Boiler Blowdown loss-average measured value

= 1% of steam flow

$\therefore$ In energy term $= 0.01 \times 3337.5$

= 33.4 KW

$\therefore$ Total heat loss + blowdown loss $= 119 + 33.4 =$ 152.4 KW

As a percentage of fuel calorific value $= \dfrac{152.4}{47{,}900 \times 0.095} =$ 3.74%

$\therefore$ From Indirect combustion efficiency, overall efficiency

= Indirect Efficiency - losses

= 85.9% - 3.74%

(Predicted) Overall Efficiency = 82.16%

Compare measured overall Efficiency value, which was equal to 82%

We can now explore the changes that would occur in useful heat release and combustion efficiency, when excess air and stack temperature varies. The figures given below are all derived from equation (5).

(1) Excess O_2 = 2% Excess air = 10% (from the curve)

TABLE 6

T (^{o}c)	Q (KW)	Efficiency (%)
300	3657	89.7
350	3579	87.8
400	3501	85.9
450	3424	84.0
500	3346	82.1

(2) Excess O_2 = 3% ∴ Excess air = 17.5%

T	Q	Efficiency
300	3646	89.4
350	3566	87.5
400	3486	85.6
450	3407	83.6
500	3327	81.6

(3) Excess O_2 = 4% ∴ Excess air = 22%

T	Q	Efficiency
300	3613	88.6
350	3527	86.6
400	3441	84.4
450	3356	82.3
500	3270	80.2

(4) Excess O_2 = 8% ∴ Excess air = 57%

T	Q	Efficiency
300	3485	85.5
350	3376	82.8
400	3267	80.1
450	3157	77.4
500	3048	74.8

Hence we can see that there is a significant variation in combustion efficiency, with Exhaust stack temperature and excess O_2. For example, if conditions are improved from (say) 4% excess O_2 and 500°C temperature, to 2% excess O_2 and 350°C temperature the change in efficiency would be equal to 87.8 - 80.2 = 7.6%.

In terms of fuel, this would be equivalent to

$$= \frac{7.6 \times 100}{100 \times 87.8} \times 0.094$$

$$= 8.2 \times 10^{-3} \text{ Kg/second of fuel}$$

$$= 47{,}760 \text{ gallons/year}$$

= <u>970,000 per year</u> (at the rate of Rs. 20.5 per gallon)

7. Power and Refrigeration Cycles

A heat engine is a device which works cyclically and either produces external work or absorbs external work to produce heating or cooling.

Engine cycles are divided into gas and vapour cycles. Simplified analyses are carried out by making up each cycle in terms of processes of the type given in section (3)

Example : Otto (Petrol engine) Cycle considered to be composed of 4 processes.
(Fig. 14)

1-2 : Reversible, adiabatic compression.

2-3 : Constant volume combustion.

3-4 : Reversible, adiabatic expansion.

4-1 : Constant volume heat rejection.

External work is always represented by the area bounded by the curves in the PV diagram. By applying the 1st law, the efficiency can be calculated.

Work Ratio is another important parameter in power cycles and is defined as :-

$$= \frac{\text{Nett external work done}}{\text{Positive work done}}$$

$$\therefore \quad W.R. = 1 - \frac{\text{Neg. Work}}{\text{Positive Work}} \quad \text{- - - - - (54)}$$

If the negative work is comparatively large (ie. W.R. Low) it means that there is a large internal flow of work, in relation to total external work. Therefore, the machinery would be bulky and capital cost high. Further and more importantly, component inefficiency would cause the overall efficiency to be seriously affected in cases where W.R. is low).

Vapour Cycles

The most important is the familiar Rankine (or steam) cycle, in which the processes can be represented as follows: (Fig. 16).

1-2, 2-3 : Heat addition in Boiler

3-4 : Adiabatic, Reversible Expansion is Turbine.

4-5 : Condensation of spent steam in condenser.

5-1 : Feed pump compression.

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$$\text{The efficiency} \doteq \frac{W}{Q_{in}} \doteq \frac{\{h_3 - h_4\} - \{h_1 - h_5\}}{\{h_3 - h_1\}} \quad \text{----} \; (55)$$

$$\text{and Work Ratio} \quad = 1 - \frac{\{h_1 - h_5\}}{\{h_3 - h_4\}} \quad \text{----} \; (56)$$

There are a number of techniques adopted to improve the efficiency of the basic Rankine Cycle, of which the most important are superheat, reheat and regenerative feed heating. In the case of superheat and reheat, additional heat is added to the steam, as shown (Fig. 16). It is found that the work output increases more than proportionately with the greater heat input, resulting in greater overall efficiency.

In regerative feedheating, the heat required in (1)-(2) is provided by steam bled from the turbine during the expansion. External heat addition in the boiler is now only in the portion (2)-(3) and is less than previously. Hence efficiency increases, at the cost of some reduction in external work output.

A refrigerator or heat pump operates on a reversed heat engine cycle ie. mechanical work input is used to transfer heat from one reservoir to another.

Example: Refrigeration Cycle (Fig.18).

The processes are -

1-2 : Vapour is compressed isentropically from a low pressure and temperature to a high pressure and temperature.

2-3 : Vapour passed through condenser where heat is transferred out to atmosphere and vapour is condensed to a liquid.

3-4 : Liquid is expanded through a throttle valve to original pressure.

4-1 : Liquid/Vapour mixture absorbs heat in evaporator.

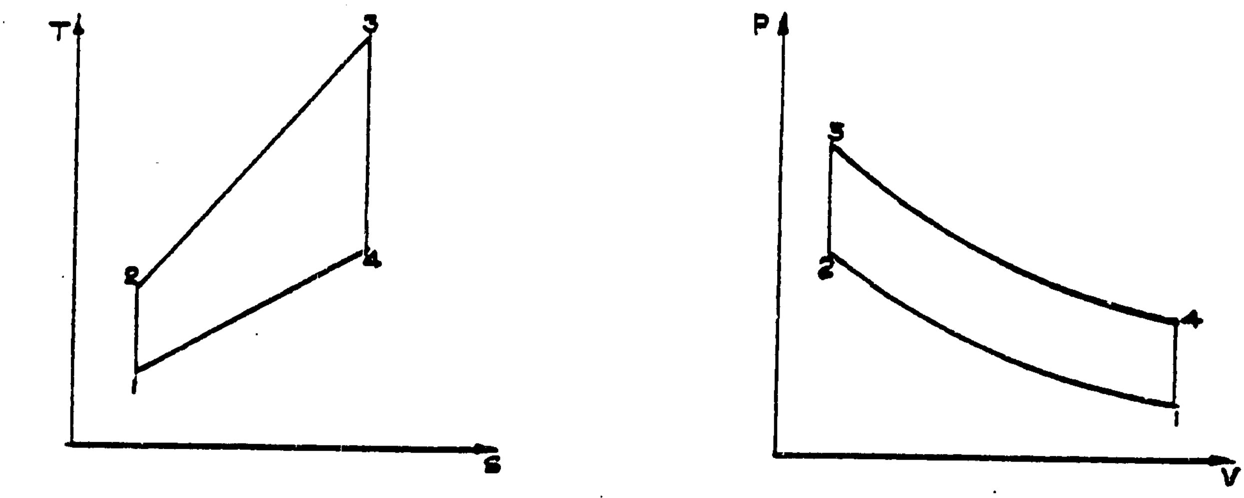
In refrigeration work, a P-h diagram is very useful, since the cycle can be represented on a chart and the heat absorbed, heat rejected and compressor work can be read off directly.

If the device was used as a heatpump, then the useful heat would be the heat rejected in the condenser.

In refrigerators and heatpumps performance is estimated by the coefficiency of performance, which is defined as follows:

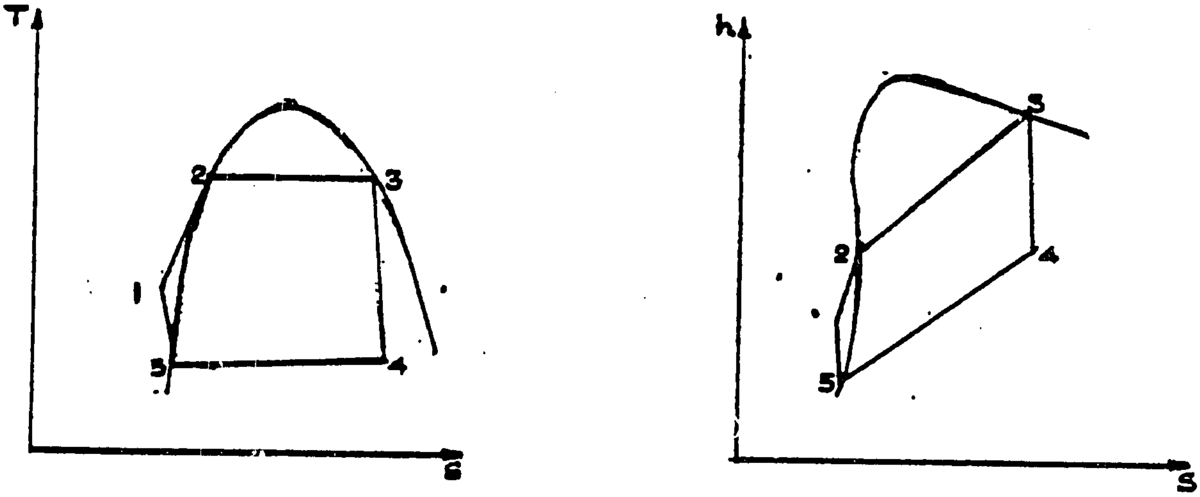
$$C_{pref} = \text{C.O.P. (refrigerator)} = \frac{\text{heat absorbed}}{\text{Work done}} = \frac{Q_{4-1}}{W_{1-2}}$$

$$C_{php} = \text{C.O.P. (Heat pump)} = \frac{\text{heat rejected}}{\text{Work done}} = \frac{Q_{2-3}}{W_{1-2}}$$



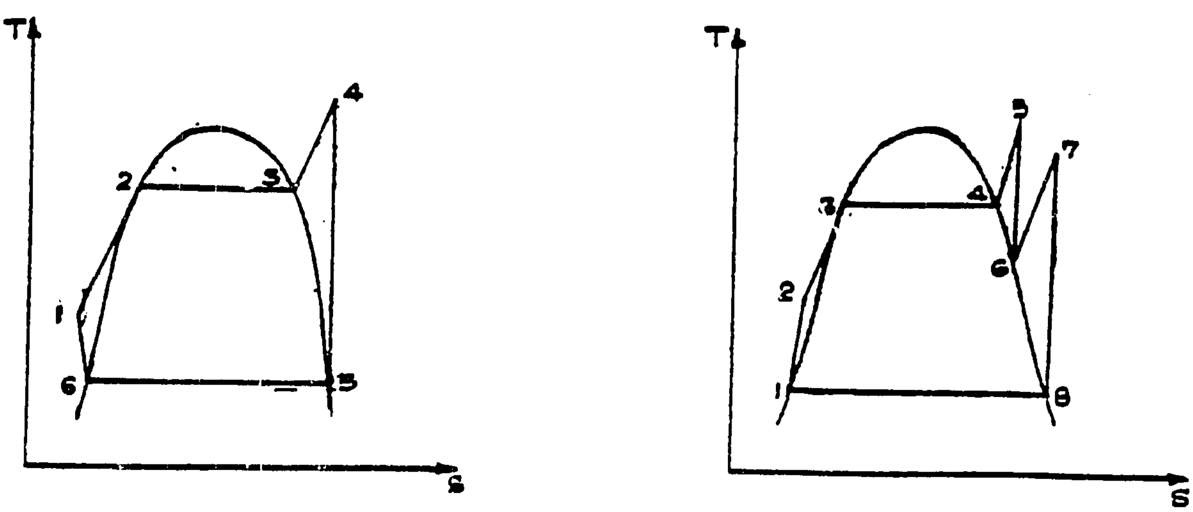
OTTO CYCLE

FIG 14 :



RANKINE CYCLE

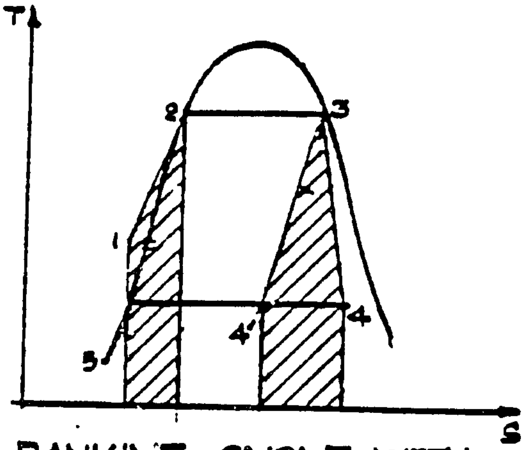
FIG 15 :



RANKINE WITH SUPERHEAT

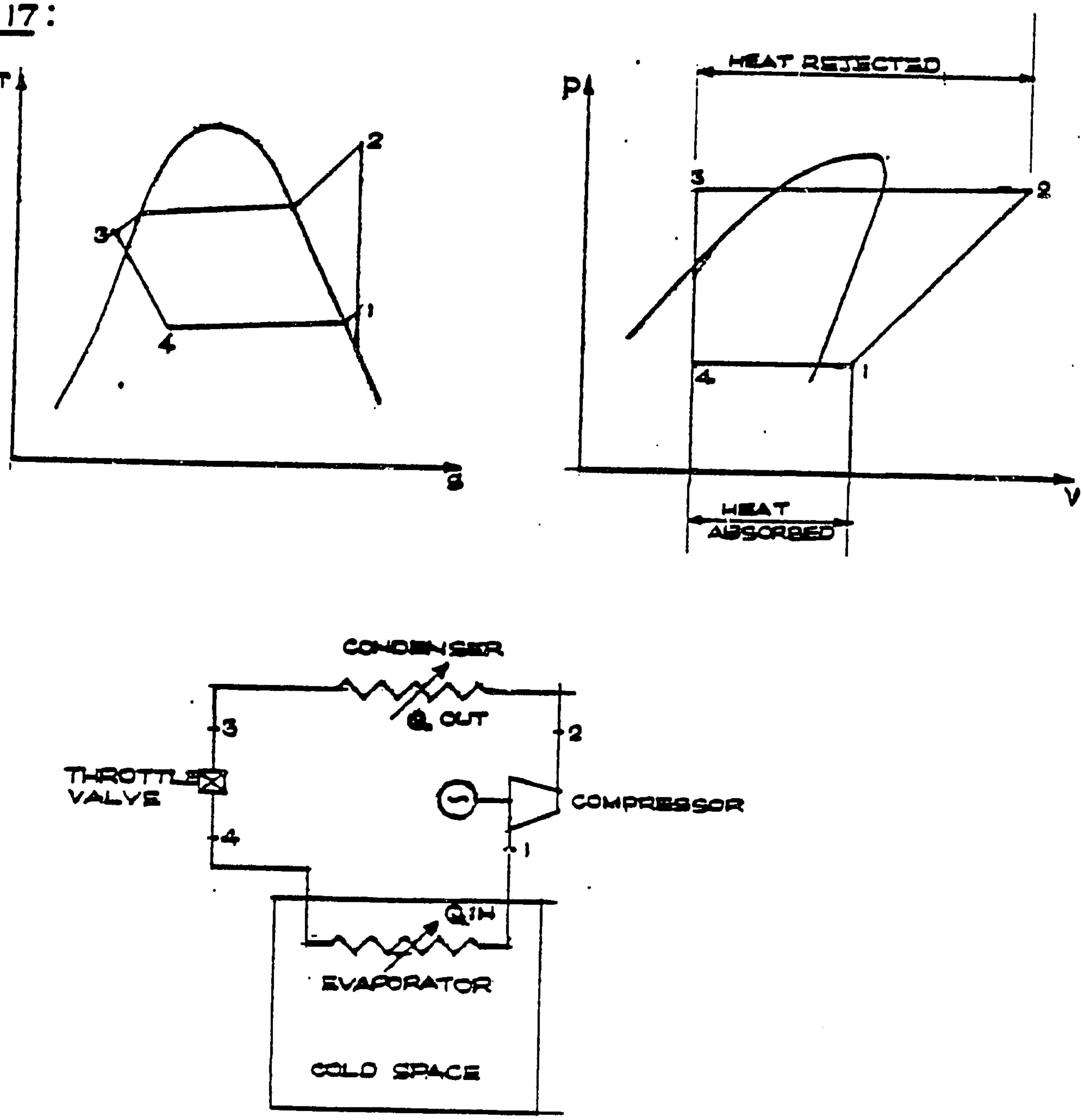
RANKINE WITH SUPERHEAT AND REHEAT

FIG 16 :



RANKINE CYCLE WITH REGENERATION

FIG 17 :



REFRIGERATION OR HEAT PUMP CYCLE

FIG 18 :.

By the 1st Law,

$$- Q_{2-3} + Q_{4-1} + W_{1-2} = 0$$

$$\therefore \quad \boxed{C_{php} = C_{pref} + 1} \quad ---- (٣٧)$$

C_{php} is > 1, ie. heat pumps always give out more heat than the amount of work put in.

8. Air/Water Vapour Mixtures

In air conditioning and drying applications, atmospheric air is cooled or heated before use. Water vapour is always present and can be considered by using the following parameters:

$$\text{Specific Humidity} = \frac{M_s}{M_a} = \omega$$

$$\text{Relative Humidity} = \frac{P_s}{P_g} = \phi \quad ---- (٣٨)$$

Where M_s = Mass of water vapour

M = Mass of air

$_s$ = Partial pressure of water vapour

P_g = Partial pressure of water vapour at ambient temperature if the air had been saturated at that temperature.

Note ϕ = Relative Humidity $= \dfrac{P_{gd}}{P_g}$ ---- (٣٩)

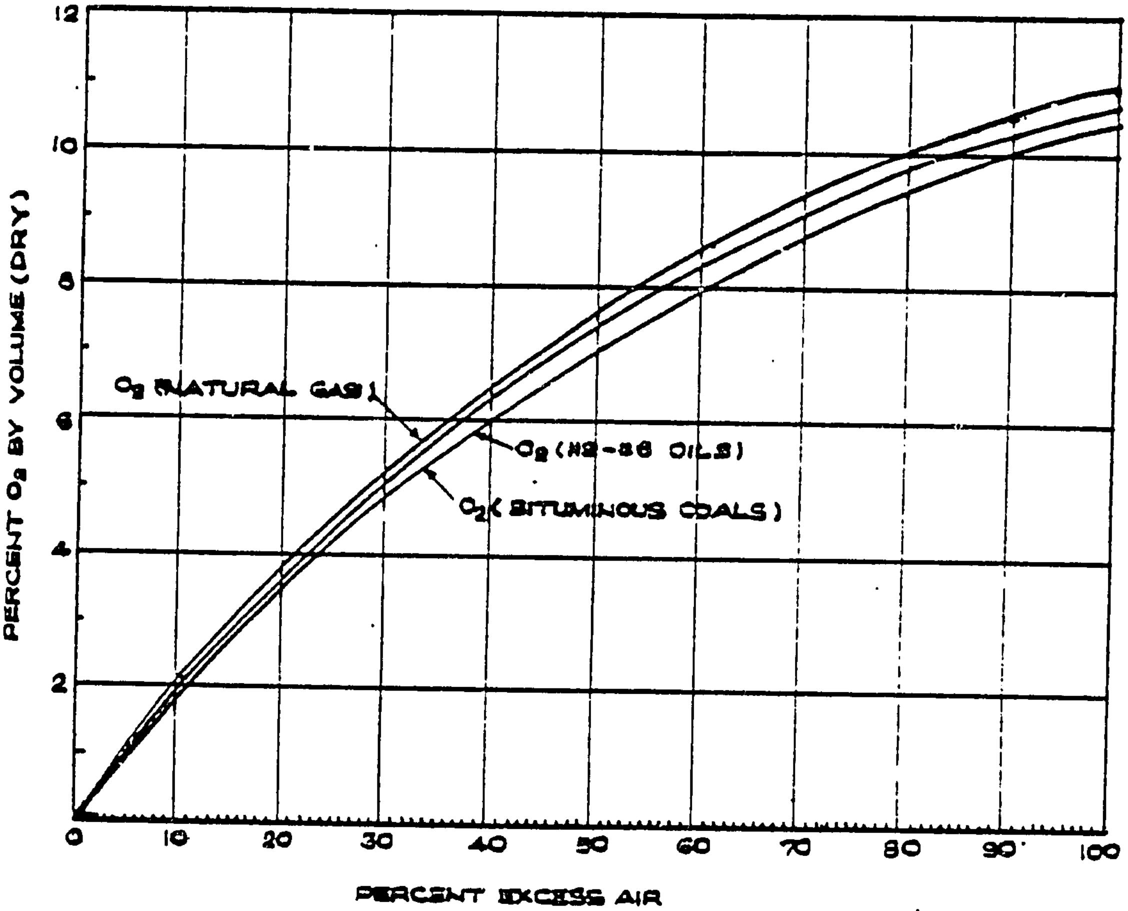
Where P_{gd} = Partial pressure of water vapour at the dew point.

The dew point is defined as the temperature at which the water vapour condensers in a particular mixture. The partial pressure is a function of the specific humidity and remains constant as the mixture is cooled.

$$P_{gd} = P_s \quad ----- (٤٠)$$

Psychrometric Charts

Calculation on air/vapour mixtures are best carried out by means of Psychrometric Charts (Fig. 20). In these charts the temperature of dry air and the specific humidity are given on the X & Y axes respectively and Enthalpy of mixture is given on a diagonal axis. Curves of constant relative humidity and wet bulb temperature are also given. The state of a vapour/air mixture can be determined if any 2 of the above variables are known.



BOILER EXCESS AIR vs STACK GAS CONCENTRATIONS OF EXCESS O_2

FIG 19:

79

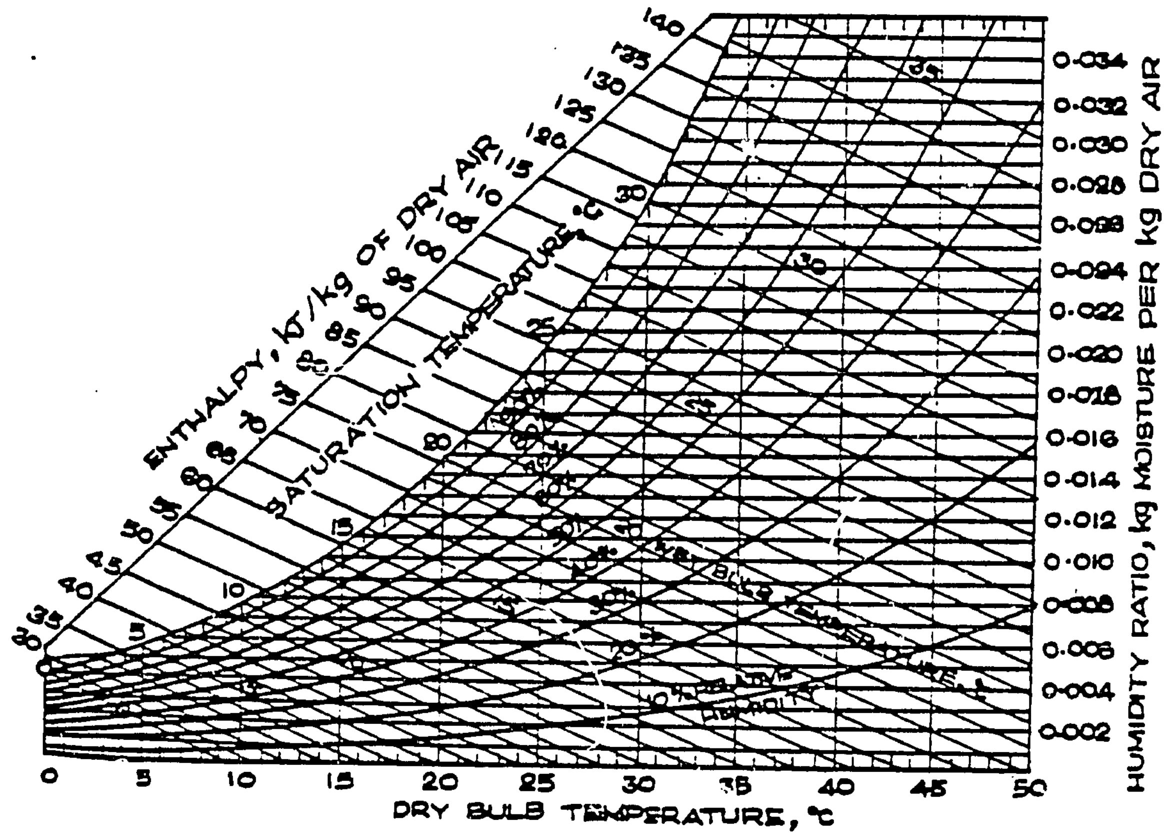


FIG 20 : PSYCHROMETRIC CHART

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3. "Drying Principles and Practice"
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4. "Heat Transmission"
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CONVERSION FACTORS

a. Thermal Conductivity

$\frac{\text{Btu}}{\text{hr-ft}^2\text{-}^\circ\text{F/ft}}$	$\frac{\text{gm-cal}}{\text{sec-cm}^2\text{-}^\circ\text{C/cm}}$	$\frac{\text{watts}}{\text{cm}^2\text{-}^\circ\text{C/cm}}$	$\frac{\text{kg-cal}}{\text{hr-m}^2\text{-}^\circ\text{C/m}}$
1	0.004134	0.01731	1.488
241.9	1	4.187	360
57.79	0.2388	1	86
0.672	C.002778	0.01163	1

b. Coefficient of Heat Transfer

$\frac{\text{Btu}}{\text{hr-ft}^2\text{-}^\circ\text{F}}$	$\frac{\text{gm-cal}}{\text{sec-cm}^2\text{-}^\circ\text{C}}$	$\frac{\text{watts}}{\text{cm}^2\text{-}^\circ\text{C}}$	$\frac{\text{kg-cal}}{\text{hr-m}^2\text{-}^\circ\text{C}}$
1	0.0001355	0.0005678	4.882
7,373	1	4.187	36,000
1,761	0.2388	1	8,600
0.2048	0.00002778	0.0001163	1

c. Heat Flux

$\frac{\text{Btu}}{\text{hr-ft}^2}$	$\frac{\text{gm-cal}}{\text{sec-cm}^2}$	$\frac{\text{watts}}{\text{cm}^2}$	$\frac{\text{kg-cal}}{\text{hr-m}^2}$
1	0.00007535	0.0003154	2,712
13,272	1	4.187	36,000
3,170	0.2388	1	8,600
0.3687	0.00002778	0.0001163	1

d. Viscosity

Centipoises	$\frac{\text{lb}}{\text{sec-ft}}$	$\frac{\text{lb force-sec}}{\text{ft}^2}$	$\frac{\text{lb}}{\text{hr-ft}}$	$\frac{\text{kg}}{\text{hr-m}}$
1	0.000672	0.0000209	2.42	3.60
1,490	1	0.0311	3600	5350
47,800	32.2	1	116,000	172,000
0.413	0.000278	0.00000864	1	1.49
0.278	0.000187	0.00000581	0.672	1

100 Centipoises = 1 poise = .1 gm/(sec. cm.)

1 Centipoise = 0.001 kg/(sec. m.)

TABLE 2 – SATURATION LINE (PRESSURE) – continued

Abs. Press. bar	Temp. °C	Specific Enthalpy kJ/kg			Specific Entropy kJ/kg °C			Specific Volume dm^3/kg		
p_s	t_s	h_f	h_{fg}	h_g	s_f	s_{fg}	s_g	v_f	v_{fg}	v_g
1.0	99.632	417.5	2257.9	2675.4	1.3027	6.0571	7.3598	1.0434	1692.7	1693.7
1.1	102.317	428.8	2250.8	2679.6	1.3330	5.9947	7.3277	1.0455	1548.2	1549.2
1.2	104.808	439.4	2244.1	2683.4	1.3609	5.9375	7.2984	1.0475	1427.1	1428.1
1.3	107.133	449.2	2237.8	2687.0	1.3868	5.8847	7.2715	1.0495	1324.0	1325.1
1.4	109.315	458.4	2231.9	2690.3	1.4109	5.8356	7.2465	1.0513	1235.3	1236.3
1.5	111.372	467.1	2226.2	2693.4	1.4336	5.7898	7.2234	1.0530	1158.0	1159.0
1.6	113.320	475.4	2220.9	2696.2	1.4550	5.7467	7.2017	1.0547	1090.1	1091.1
1.7	115.170	483.2	2215.7	2699.0	1.4752	5.7061	7.1813	1.0563	1029.9	1030.9
1.8	116.933	490.7	2210.8	2701.5	1.4944	5.6678	7.1622	1.0579	976.17	977.23
1.9	118.617	497.8	2206.1	2704.0	1.5127	5.6314	7.1440	1.0594	927.94	929.00
2.0	120.231	504.7	2201.6	2706.3	1.5301	5.5967	7.1268	1.0608	884.38	885.44
2.1	121.780	511.3	2197.2	2708.5	1.5468	5.5637	7.1105	1.0622	844.84	845.90
2.2	123.270	517.6	2193.0	2710.6	1.5627	5.5321	7.0949	1.0636	808.78	809.84
2.3	124.705	523.7	2188.9	2712.6	1.5781	5.5019	7.0800	1.0650	775.75	776.81
2.4	126.091	529.6	2184.9	2714.5	1.5929	5.4728	7.0657	1.0663	745.38	746.45
2.5	127.430	535.3	2181.0	2716.4	1.6071	5.4449	7.0520	1.0675	717.37	718.44
2.6	128.727	540.9	2177.3	2718.2	1.6209	5.4180	7.0389	1.0688	691.44	692.51
2.7	129.984	546.2	2173.6	2719.9	1.6342	5.3920	7.0262	1.0700	667.37	668.44
2.8	131.203	551.4	2170.1	2721.5	1.6471	5.3670	7.0140	1.0712	644.97	646.04
2.9	132.388	556.5	2166.6	2723.1	1.6595	5.3427	7.0023	1.0723	624.05	625.12
3.0	133.540	561.4	2163.2	2724.7	1.6716	5.3193	6.9909	1.0735	604.49	605.56
3.1	134.661	566.2	2159.9	2726.1	1.6834	5.2966	6.9799	1.0746	586.14	587.22
3.2	135.753	570.9	2156.7	2727.6	1.6948	5.2744	6.9692	1.0757	568.91	569.99
3.3	136.819	575.5	2153.5	2729.0	1.7059	5.2530	6.9589	1.0768	552.68	553.76
3.4	137.858	579.9	2150.4	2730.3	1.7168	5.2322	6.9489	1.0778	537.38	538.46
3.5	138.873	584.3	2147.4	2731.6	1.7273	5.2119	6.9392	1.0789	522.92	524.00
3.6	139.865	588.5	2144.4	2732.9	1.7376	5.1921	6.9297	1.0799	509.24	510.32
3.7	140.835	592.7	2141.4	2734.1	1.7476	5.1729	6.9205	1.0809	496.28	497.36
3.8	141.784	596.8	2138.6	2735.3	1.7574	5.1541	6.9116	1.0819	483.97	485.05
3.9	142.713	600.8	2135.7	2736.5	1.7670	5.1358	6.9028	1.0829	472.27	473.36
4.0	143.623	604.7	2133.0	2737.6	1.7764	5.1179	6.8943	1.0839	461.14	462.22
4.2	145.390	612.3	2127.5	2739.8	1.7945	5.0834	6.8779	1.0857	440.41	441.50
4.4	147.090	619.6	2122.3	2741.9	1.8120	5.0503	6.8623	1.0876	421.51	422.50
4.6	148.729	626.7	2117.2	2743.9	1.8287	5.0186	6.8473	1.0894	404.19	405.28
4.8	150.313	633.5	2112.2	2745.7	1.8448	4.9881	6.8329	1.0911	388.27	389.36
5.0	151.844	640.1	2107.4	2747.5	1.8604	4.9588	6.8192	1.0928	373.58	374.68
5.2	153.327	646.5	2102.7	2749.3	1.8754	4.9306	6.8059	1.0945	359.99	361.08
5.4	154.765	652.8	2098.1	2750.9	1.8899	4.9033	6.7932	1.0961	347.38	348.48
5.6	156.161	658.8	2093.7	2752.5	1.9040	4.8769	6.7809	1.0977	335.61	336.71
5.8	157.518	664.7	2089.3	2754.0	1.9176	4.8514	6.7690	1.0993	324.64	325.74
6.0	158.838	670.4	2085.0	2755.5	1.9308	4.8267	6.7575	1.1009	314.37	315.47
6.2	160.123	676.0	2080.9	2756.9	1.9437	4.8027	6.7464	1.1024	304.75	305.85
6.4	161.376	681.5	2076.8	2758.2	1.9562	4.7794	6.7356	1.1039	295.70	296.81
6.6	162.598	686.8	2072.7	2759.5	1.9684	4.7568	6.7252	1.1053	287.19	288.30
6.8	163.791	692.0	2068.9	2760.8	1.9802	4.7348	6.7150	1.1068	279.16	280.27
7.0	164.956	697.1	2064.9	2762.0	1.9918	4.7134	6.7052	1.1082	271.57	272.68
7.2	166.095	702.0	2061.1	2763.2	2.0031	4.6925	6.6956	1.1096	264.39	265.50
7.4	167.209	706.9	2057.4	2764.3	2.0141	4.6721	6.6862	1.1110	257.59	258.70
7.6	168.300	711.7	2053.7	2765.4	2.0249	4.6522	6.6771	1.1123	251.13	252.24
7.8	169.368	716.3	2050.1	2766.4	2.0354	4.6328	6.6683	1.1137	244.99	246.10
8.0	170.415	720.9	2046.5	2767.5	2.0457	4.6139	6.6596	1.1150	239.14	240.26
8.2	171.441	725.4	2043.0	2768.5	2.0558	4.5953	6.6511	1.1163	233.57	234.69
8.4	172.448	729.9	2039.6	2769.4	2.0657	4.5772	6.6429	1.1176	228.26	229.38
8.6	173.436	734.2	2036.2	2770.4	2.0753	4.5594	6.6348	1.1188	223.19	224.30
8.8	174.405	738.5	2032.8	2771.3	2.0848	4.5421	6.6269	1.1201	218.33	219.45
9.0	175.358	742.6	2029.5	2772.1	2.0941	4.5250	6.6192	1.1213	213.69	214.81
9.2	176.294	746.8	2026.2	2773.0	2.1033	4.5083	6.6116	1.1226	209.24	210.36
9.4	177.214	750.8	2023.0	2773.8	2.1122	4.4920	6.6042	1.1238	204.98	206.10
9.6	178.119	754.8	2019.8	2774.6	2.1210	4.4759	6.5969	1.1250	200.88	202.01
9.8	179.009	758.7	2016.7	2775.4	2.1297	4.4601	6.5898	1.1262	196.95	198.07
10.0	179.884	762.6	2013.6	2776.2	2.1382	4.4446	6.5828	1.1274	193.17	194.29

BLE 3 — PROPERTIES OF WATER AND STEAM — continued

(abs.) bar	10.0			10.5			11.0			11.5			12.0			12.5		
°C	179.9			182.0			184.1			186.0			188.0			189.8		
	h	s	v	h	s	v	h	s	v	h	s	v	h	s	v	h	s	v
Liquid	782.6	2.1382	1.1274	772.0	2.1588	1.1303	781.1	2.1786	1.1331	789.9	2.1977	1.1359	798.4	2.2161	1.1386	806.7	2.2338	1.1412
Vapour	2776.2	6.5828	194.29	2778.0	6.5659	186.45	2779.7	6.5497	177.38	2781.3	6.5342	169.99	2782.7	6.5184	163.20	2784.1	6.5050	156.93
°C																		
.01	1.02	0.0001	0.99971	1.07	0.0001	0.99969	1.12	0.0001	0.99966	1.18	0.0001	0.99964	1.23	0.0001	0.99961	1.28	0.0001	0.99959
10	42.97	0.1509	0.99977	43.02	0.1509	0.99975	43.07	0.1509	0.99973	43.12	0.1509	0.99970	43.16	0.1509	0.99968	43.21	0.1509	0.99965
20	84.80	0.2961	1.0013	84.85	0.2961	1.0012	84.89	0.2961	1.0012	84.94	0.2961	1.0012	84.99	0.2960	1.0012	85.03	0.2960	1.0011
30	126.57	0.4362	1.0039	126.62	0.4362	1.0038	126.66	0.4362	1.0038	126.71	0.4362	1.0038	126.75	0.4361	1.0038	126.80	0.4361	1.0037
40	168.33	0.5717	1.0074	168.37	0.5717	1.0073	168.42	0.5717	1.0073	168.46	0.5717	1.0073	168.51	0.5717	1.0073	168.55	0.5716	1.0072
50	210.11	0.7031	1.0117	210.15	0.7030	1.0116	210.19	0.7030	1.0116	210.24	0.7030	1.0116	210.28	0.7030	1.0116	210.32	0.7029	1.0115
60	251.91	0.8305	1.0167	251.95	0.8304	1.0167	252.00	0.8304	1.0166	252.04	0.8304	1.0166	252.08	0.8304	1.0166	252.12	0.8303	1.0166
70	293.76	0.9542	1.0224	293.80	0.9542	1.0224	293.84	0.9542	1.0223	293.89	0.9541	1.0223	293.93	0.9541	1.0223	293.97	0.9541	1.0223
80	335.67	1.0746	1.0287	335.71	1.0746	1.0287	335.75	1.0746	1.0287	335.79	1.0745	1.0286	335.83	1.0745	1.0286	335.87	1.0745	1.0286
90	377.66	1.1919	1.0357	377.70	1.1918	1.0356	377.73	1.1918	1.0356	377.77	1.1917	1.0356	377.81	1.1917	1.0356	377.85	1.1917	1.0355
00	419.74	1.3062	1.0432	419.78	1.3061	1.0432	419.81	1.3061	1.0432	419.85	1.3060	1.0431	419.89	1.3060	1.0431	419.93	1.3060	1.0431
10	461.94	1.4178	1.0514	461.97	1.4177	1.0514	462.01	1.4177	1.0513	462.05	1.4176	1.0513	462.08	1.4176	1.0513	462.12	1.4176	1.0512
20	504.28	1.5269	1.0602	504.32	1.5268	1.0601	504.35	1.5268	1.0601	504.39	1.5267	1.0601	504.42	1.5267	1.0600	504.46	1.5266	1.0600
30	546.80	1.6337	1.0696	546.83	1.6336	1.0695	546.87	1.6336	1.0695	546.90	1.6335	1.0695	546.94	1.6335	1.0694	546.97	1.6334	1.0694
40	589.52	1.7383	1.0796	589.55	1.7383	1.0796	589.58	1.7382	1.0796	589.62	1.7382	1.0795	589.65	1.7381	1.0795	589.68	1.7381	1.0795
50	632.47	1.8411	1.0904	632.50	1.8410	1.0904	632.54	1.8409	1.0903	632.57	1.8409	1.0903	632.60	1.8408	1.0903	632.63	1.8408	1.0902
60	675.70	1.9420	1.1019	675.73	1.9420	1.1019	675.76	1.9419	1.1019	675.79	1.9418	1.1018	675.82	1.9418	1.1018	675.84	1.9417	1.1017
70	719.23	2.0414	1.1143	719.26	2.0413	1.1142	719.29	2.0412	1.1142	719.31	2.0412	1.1142	719.34	2.0411	1.1141	719.37	2.0411	1.1141
80	2776.5	6.5835	194.36	763.14	2.1392	1.1275	763.17	2.1392	1.1274	763.19	2.1391	1.1274	763.22	2.1390	1.1273	763.24	2.1390	1.1273
90	2802.0	6.6392	200.22	2798.6	6.6108	189.95	2795.2	6.5834	180.61	2791.7	6.5569	172.07	2788.2	6.5312	164.24	2784.6	6.5061	157.02
00	2826.8	6.6922	205.92	2823.8	6.6645	195.45	2820.7	6.6379	185.92	2817.6	6.6121	177.22	2814.4	6.5872	169.23	2811.2	6.5630	161.88
05	2838.9	6.7177	208.71	2836.1	6.6904	198.14	2833.1	6.6641	188.52	2830.2	6.6387	179.73	2827.2	6.6141	171.67	2824.2	6.5902	164.25
10	2851.0	6.7427	211.48	2848.2	6.7157	200.80	2845.6	6.6897	191.09	2842.7	6.6646	182.22	2839.8	6.6403	174.08	2837.0	6.6168	166.59
15	2862.8	6.7672	214.22	2860.2	6.7405	203.44	2857.8	6.7147	193.63	2854.9	6.6899	184.67	2852.3	6.6659	176.46	2849.5	6.6427	168.89
20	2874.6	6.7911	216.93	2872.1	6.7647	206.04	2869.6	6.7392	196.14	2867.1	6.7147	187.10	2864.6	6.6909	178.80	2861.9	6.6680	171.17
25	2886.2	6.8146	219.62	2883.9	6.7884	208.63	2881.5	6.7632	198.63	2879.1	6.7389	189.60	2876.7	6.7164	181.12	2874.2	6.6927	173.41
30	2897.8	6.8377	222.28	2895.5	6.8117	211.18	2893.2	6.7867	201.09	2891.0	6.7626	191.87	2888.6	6.7393	183.42	2886.3	6.7169	175.64
35	2909.2	6.8603	224.93	2907.1	6.8345	213.72	2904.9	6.8097	203.53	2902.7	6.7858	194.23	2900.5	6.7628	185.69	2898.3	6.7405	177.84
40	2920.6	6.8825	227.66	2918.6	6.8569	216.24	2916.4	6.8323	205.98	2914.4	6.8086	196.60	2912.2	6.7858	187.95	2910.1	6.7637	180.02
45	[illegible]	6.9044	230.16	2929.9	6.8790	218.74	2927.9	6.8545	208.36	2925.9	6.8310	198.88	2923.9	6.8084	190.18	2921.9	6.7865	182.18
50	2943.0	6.9259	232.76	2941.2	6.9006	221.22	2939.3	6.8764	210.75	2937.4	6.8530	201.18	2935.4	6.8305	192.40	2933.6	6.8088	184.33
55	2954.2	6.9471	235.32	2952.4	6.9220	223.69	2950.6	6.8978	213.12	2948.7	6.8747	203.46	2946.9	6.8523	194.60	2945.0	6.8308	186.45
60	2965.2	6.9679	237.88	2963.6	6.9430	226.15	2961.8	6.9190	215.47	2960.0	6.8959	205.73	2958.2	6.8737	196.79	2956.5	6.8523	188.56
65	2976.3	6.9885	240.43	2974.6	6.9636	228.69	2972.9	6.9398	217.82	2971.2	6.9169	207.98	2969.5	6.8948	198.98	2967.8	6.8735	190.66
70	2987.2	7.0088	242.97	2985.6	6.9840	231.02	2984.0	6.9603	220.15	2982.4	6.9376	210.22	2980.8	6.9156	201.12	2979.1	6.8944	192.74

Enthalpies of formation, h'_f, and molar heats at constant pressure, Cp, of substances at 25°C, 1 atmosphere

Substance		Phase	h'_f Btu/lb mole	h'_f kJ/kg-mole	Cp Btu/lb-mole R	Cp kJ/kg-mole K
Graphite	C	solid	zero by definition	zero by definition	2.066	8.644
Hydrogen	H_2	gas			6.892	28.836
Nitrogen	N_2	gas			6.960	29.121
Oxygen	O_2	gas			7.017	29.359
Carbon monoxide	CO	gas	-47 548	-110 523	6.965	29.142
Carbon dioxide	CO_2	gas	-169 293	-393 513	8.874	37.129
Steam	H_2O	gas	-104 036	-241 825	8.025	33.577
Water	H_2O	liquid	-122 971	-285 839	17.996	75.295
Methane	CH_4	gas	-32 200	-74 848	8.536	35.715
Ethane	C_2H_6	gas	-36 425	-84 667	12.585	52.656
Propane	C_3H_8	gas	-44 676	-103 847	17.57	73.51
n-Butane	C_4H_{10}	gas	-53 662	-124 733	23.61	98.78
		liquid	-62 910	-146 231	-	-
n-Pentane	C_5H_{12}	gas	-63 000	-146 440	29.30	122.59
		liquid	-74 448	-173 050	-	-
n-Hexane	C_6H_{14}	gas	-71 928	-167 193	35.06	146.69
		liquid	-85 536	-198 824	-	-
n-Heptane	C_7H_{16}	gas	-80 802	-187 820	40.82	170.79
		liquid	-96 534	-224 388	53.7	224.7
n-Octane	C_8H_{18}	gas	-89 676	-208 447	46.58	194.89
		liquid	-107 532	-249 952	-	-
Ethylene	C_2H_4	gas	+22 493	+52 283	10.41	43.56
Propylene	C_3H_6	gas	+8 782	+20 414	15.27	63.89
Acetylene	C_2H_2	gas	+97 549	+226 748	10.499	43.928
Benzene	C_6H_6	gas	+35 676	+82 927	19.52	81.67
		liquid	+21 092	+49 028	32.6	136.4
Toluene	C_7H_8	gas	+21 510	+49 999	24.80	103.76
Cyclohexane	C_6H_{12}	gas	-52 974	-123 135	25.40	106.27
		liquid	-67 212	-156 231	-	-
Methyl alcohol	CH_4O	gas	-86 904	-202 004	-	-
		liquid	-102 996	-239 408	19.5	81.59
Ethyl alcohol	C_2H_6O	gas	-101 934	-236 940	-	-
		liquid	-120 150	-279 282	26.64	111.46
Hydrogen peroxide	H_2O_2	gas	-57 294	-133 177	-	-
		liquid	-80 712	-187 611	-	-

References:

Kaye and Laby — "Tables of physical and chemical constants" 12th Edition.

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Energy Demand Management and Conservation Training Course

December 1983

Engineering Refresher : Electrical Engineering

G.T. Fernando
Tilak Siyambalapitiya.

Ceylon Electricity Board.

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Electrical Engineering Refresher

1. Alternating Currents

(a)- Alternating currents as used for commercial purposes is the result of an alternating electro motive force (emf) produced by an alternator. This can be represented as a rotating vector at a specified speed namely the angular frequency (ω) and the resulting output follows a sine waveform.

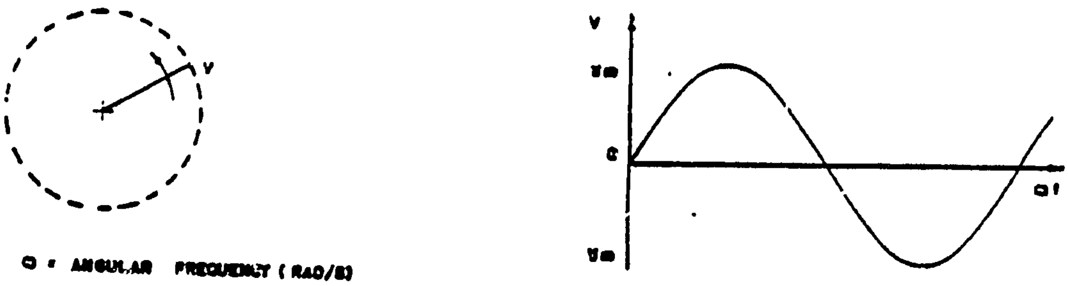

Fig.1 SINGLE PHASE ALTERNATING VOLTAGE

Figure 1 is a graphical representation of this rotating vector and the resulting voltage, which has a peak value of v_M and an instantaneous value of V_i. The relationship between V_i and v_m at any time is given by the expression

$$\boxed{Vi = v_m \sin \omega t}$$

The resulting alternating current rarely atains its maximum and zero values at the same instant as the emf. Figure 2 shows this displacement in graphical form in a typical case where the distance ab on the zero line represents a displacement or the phase difference.

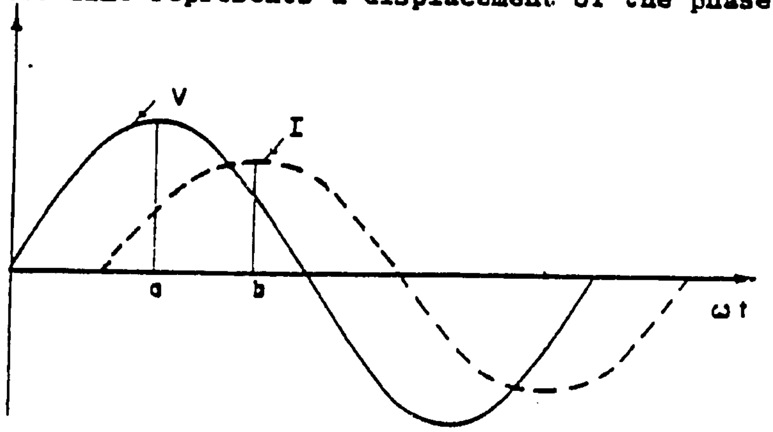

Fig. 2. Alternating voltage and the resulting current .

Root mean square (RMS) values and average values

Root mean square value of an alternating voltage or current is the equivalent direct voltage or current which would deliver the same quantity of power from a given device.

Root mean square (RMS) voltage = Vrms

$$\boxed{V_{rms} = \frac{v_m}{\sqrt{2}} = 0.707\ v_m}$$

All voltages and currents are expressed in their RMS values for practical purposes.

Over a complete cycle, the average value Vav = 0

(b) Three phase systems

Three phase supplies are derived from a source in which are generated three alternating emf's of equal RMS value, but differing in phase by 1/3 cycle or 120 degrees. The line to line RMS voltage is utilized to specify a three phase system.

Figure 3 graphically represents the three rotating vectors mutually displaced at an angle of 120° and the three resulting voltages. The current flowing in the three phase would also be similarly displaced.

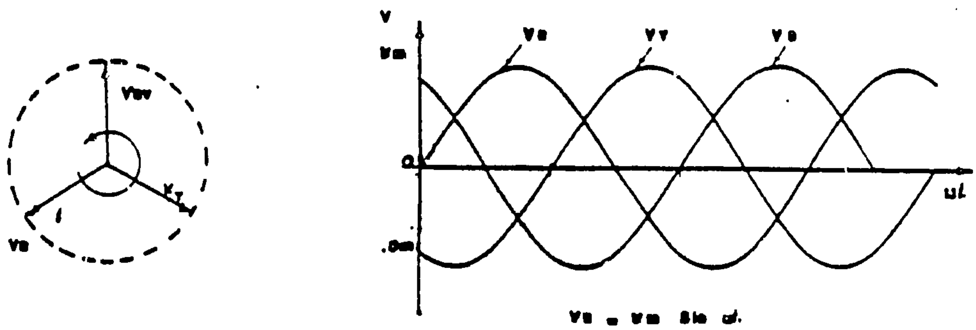

Fig.3 A THREE PHASE SYSTEM

$$\boxed{\begin{aligned} V_R &= v_m \ \mathrm{Sin}\ \omega t \\ V_Y &= v_m \ \mathrm{Sin}\ (\omega t + 120^\circ) \\ V_B &= v_m \ \mathrm{Sin}\ (\omega t - 120^\circ) \end{aligned}}$$

(c) Frequency : - In general terms, the rotational speed of the vector V for either single phase or three phase systems is the frequency (f) of the supply and is expressed in either cycles per second (Hertz)or in radians per second (ω)

$$\boxed{f = \frac{\omega}{2\pi}}$$

Standard supply frequency in Sri Lanka is 50 Hz

(d) Rectified Alternating Voltages

An alternating voltage may be rectified to obtain a uni-directional voltage and a flow of current.

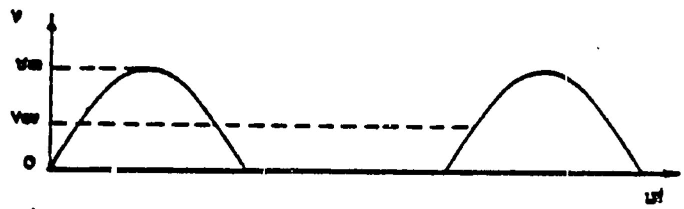

Fig 4 HALF - WAVE RECTIFICATION

Half wave rectified average voltage, Vav $= \frac{1}{\pi} V_m$

RMS voltage, Vrms $= \frac{V_m}{2}$

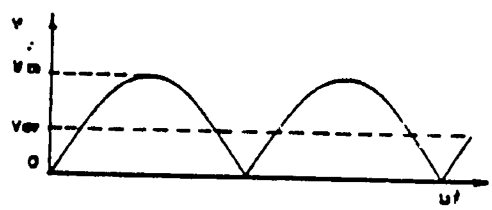

Fig. 5 FULL - WAVE RECTIFICATION

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Full wave rectfied average voltage Vav $= \frac{2}{\pi} V_m$

RMS Voltage Vrms $= \frac{V_m}{\sqrt{2}}$

(e) Basic Electrical Circuit Elements

Figure 6(a) - (c) show basic electrical circuit elements and their characteristics with respect to the voltages and currents.

The impedance (Z) of each circuit is indicated below each circuit diagram.

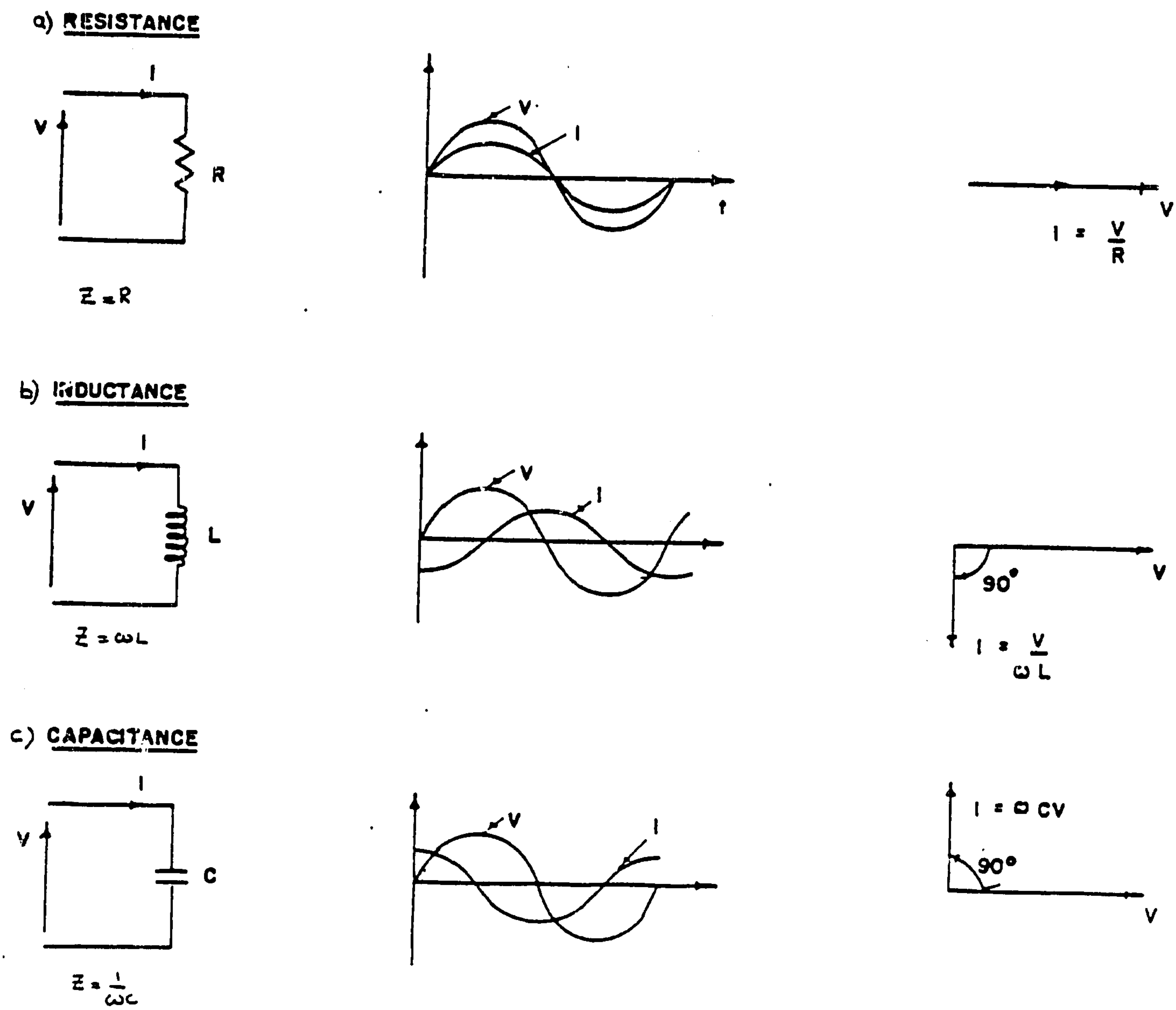


Fig. 6 Basic electrical circuit elements

(f) Three phase star connected and delta connected loads.

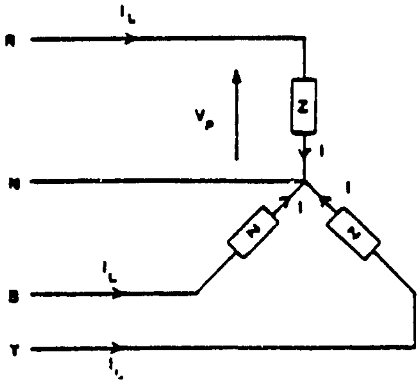


Fig 7a. Star Connected Balanced Load

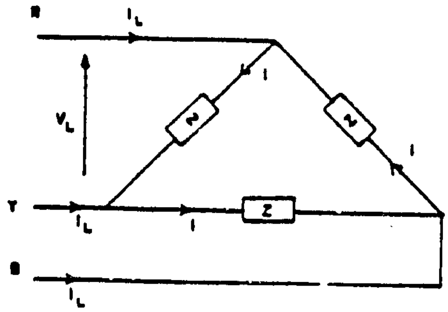


Fig 7b Delta Connected Balanced Load

Line Voltage = V_L

Phase Voltage V_p = $\frac{V_L}{\sqrt{3}}$

Phase current I = Line Current I_L

Power drawn P = $\sqrt{3}\ V_L I_L \cos\phi$

Line Voltage = V_L

Phase voltage V_p = Line Voltage V_L

Phase current I = $\frac{I_L}{\sqrt{3}}$

Power drawn = $\sqrt{3}\ V_L I_L \cos\phi$

(g) <u>Units of Measurement for basic Electrical quantities</u>

Quantity	Name	Symbol
Voltage	Volt	V
Current	ampere	A
Charge	coulomb	C
Resistance	ohm	Ω
Inducrance		H
Capacitance	farad	F
Conductance		S
Magnetic flux	Weber	Wb
Magnetic flux density	tesla	T
Power	watt	W
Work	joule	J

(2) Electrical power and energy

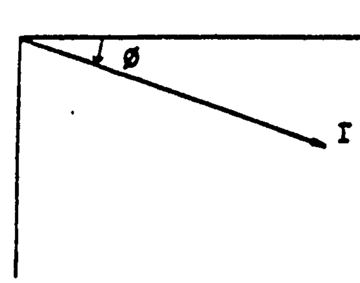


Fig. 8 Power factor angle

(a) Power factor angle (ϕ)

Power factor angle is the angular difference between the voltage and the current through a load and is dependent on the load characteristics.

(b) Power factor

The cosine of the power factor angle ϕ is defined as the power factor of the corresponding load.

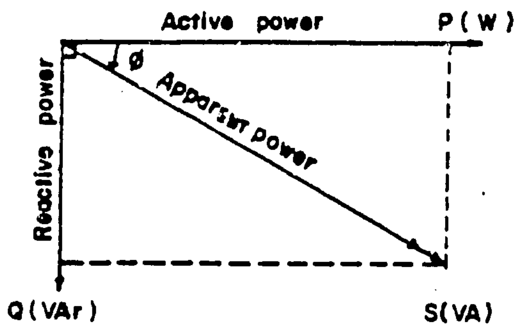


Fig. 9. Apparent, active & reactive power

(c) Apparent Power (S)

Apparent power is defined as follows

Single phase, $\boxed{S = V_p \times I_p}$ (V_p = phase voltage
I_p = phase current)

Three phase, $\boxed{S = V3\ V_L\ I_L}$ (V_L = line to line voltage
I_L = line current)

Apparent power is measured in Volt-Ampere (VA)

(d) Active Power (P)

Active power is the component of the apparent power which may be usefully converted into another form of energy and is measured in watts (W).

Single phase	P	$= V_p\ I_p\ \cos\phi$
Three phase	P	$= \sqrt{3}\ V_L\ I_L\ \cos\phi$

($\cos\phi$ = power factor)

(e) Reactive Power (Q)

All electrical equipment making use of an electro-magnetic field require power to set up and maintain this field, apart from the real or active power consumed by the equipment. This component of the aparent power is known as the reactive power.

The reactive power and the real power are 90° out of phase. Reactive power is measured in Volt Ampere - reactive. (VAr)

Single phase	Q	$= V_p I_p\ \sin\phi$
Three phase	Q	$= \sqrt{3} V_L I_L\ \sin\phi$

The following relationship are also relevant.

$$S^2 = P^2 + Q^2$$

$$\cos\phi = \frac{P}{\sqrt{P^2 + Q^2}}$$

$$\tan\phi = \frac{Q}{P}$$

(f) Energy Consumption

The energy consumption (J) is the product of the real power P (usually in killowatt) and time t (usually in hours)

$$J = P \times t \quad \text{kWh}$$

(g) Electric Heating

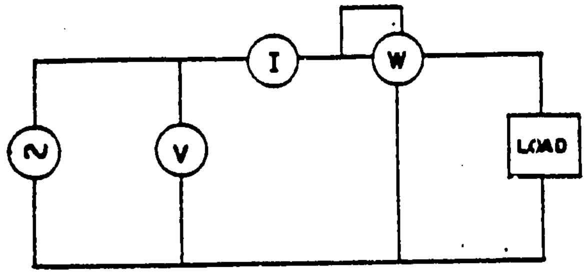
Electric heat is defined as follows

Single phase	H	$= V_p \times I_p$	Watts
Three phase	H	$= \sqrt{3}\ V_L I_L$	Watts

3. Measurement and improvement of power factor

a. Power Factor Measurement

The simplest method is by measuring the real power P using a watt meter and the voltage and the current . A typical circuit is given in figure below.



W - wattmeter reading
V - voltmeter "
I - amneter "

Fig. 9, Measurement of Power factor of a single phase load.

$$\text{Cos } \emptyset = \frac{W}{V \times I}$$

For a three - phase load, individual power factors of each phase is determined and the average is calculated. Meters for reading power factor directly are also available.

b. Effects of a high power factor angle Ø (a low power factor Cos Ø)

(i) Registration of a high maximum demand. (KVA or apparent power)

(ii) Resulting higher current drawn from the supply.

(iii) Increased losses in transformers and distribution system of both the user and the supply authority.

(iv) Under utilization of installation facilities.

(v) Poor voltage regulation.

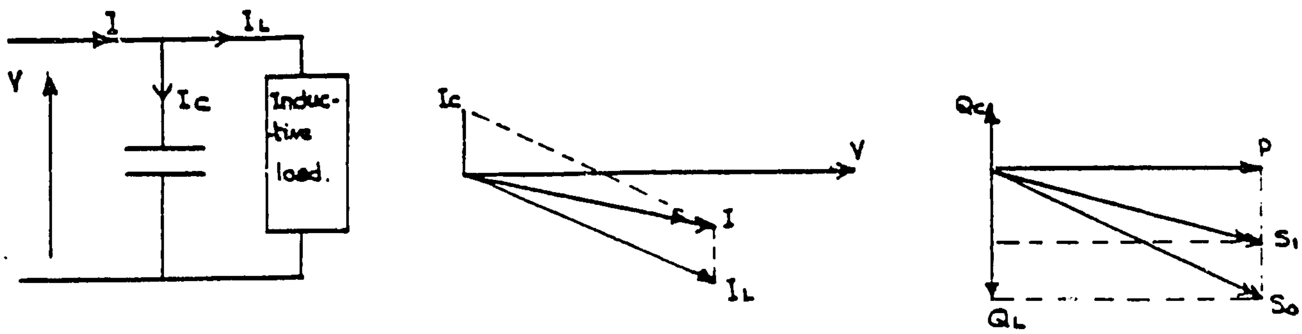


Fig. 10 : Power factor correction.

I_L = Load current

I_c = Capacitor current

I = resultant current

P = Load active power

Qr = Load reactive power (lagging)

Q_c = Leading reactive power taken by capacitor

S_o = Apparent power W/O capacitor

S_1 = Apparent power with capacitor

As seen from above diagrams,

$I < I_L$

$S_1 < So$

Eg. : Consider a case of a plant with a maximum demand of 350 KVA and operating with a power factor of 0.65. The desired improvement is to raise the power factor to 0.95. The supply voltage is 400 V, 3 - phase.

$$\text{Present current} = \frac{350 \times 10^3}{\sqrt{3} \times 400} = 505.18 \text{ A}$$

Real power demand, $P = 350 \times 0.65 = 227.5$ kW

Present reactive power, $Q_1 = 350 \times \sin \phi_1$

$= 265.97$ kVAr

Reactive power demand with improved power factor $Q_2 = P \tan \phi_2$

$= 227.5 \times 0.33$

$= 74.77$ kVAr

$\cos\phi_1 = 0.65$

$\sin\phi_1 = 0.76$

$\cos\phi_2 = 0.95$

$\tan\phi_2 = 0.33$

Reactive power requirement $= Q_1 - Q_2$

$= 191.2$ kVAr

$\therefore$ A 400 V 3 phase capacitor bank of 191.2 kVAr is required.

In practice, the kVAr required to correct the power factor of a given load (in kW) from the existing value to a desired value, can be conveniently worked out using the following nomogram.

Draw a straight line from the existing value of Cos Ø on the left to the desired value of Cos Ø on the right. This line will intersect the middle scale at a point denoting a multiplying factor K. Multiplying the existing load in KW by K gives the required KVA_r capacity.

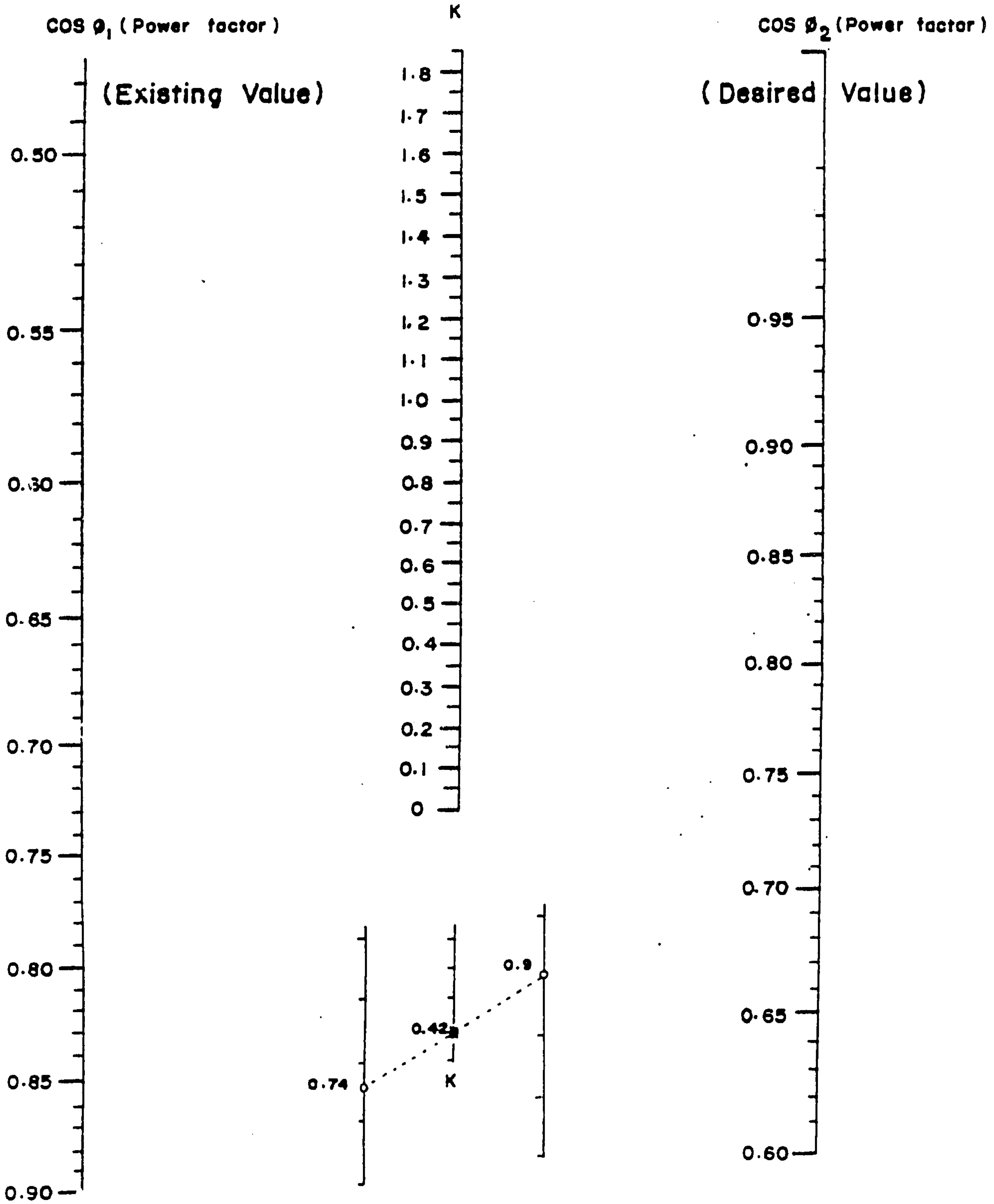


Fig. 11 ; Nomogram to calculate capacitor ratings for power factor correction.

4. Power and Energy Measuring Instruments

(a) Measurement of real power consumption of a 3 phase load

(i) A Balanced load (Two Wattmeter method)

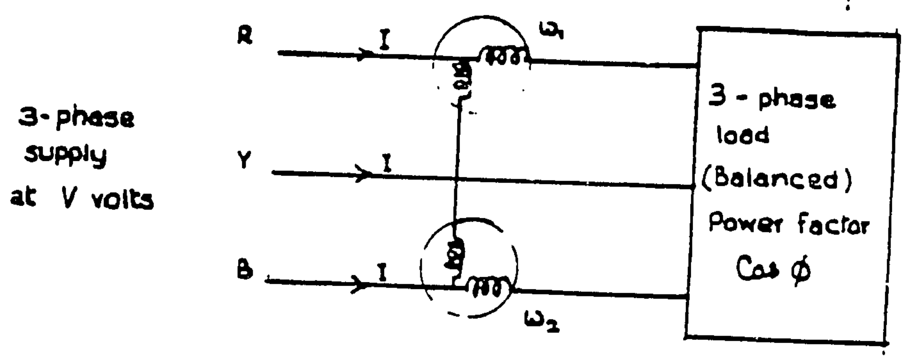
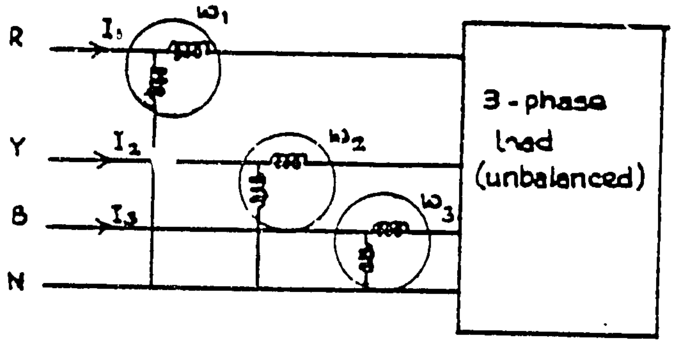


Fig. 12 : Two wattmeter method for measurement of power

Total real power consumption of the load $= W1 + W2$

$= \sqrt{3}VICos\emptyset$

(ii) An unbalanced load (three Wattmeter method)



Total real power consumption of the load $= W1 + W_2 + W_3$

$= V_p I_1 \; Cos\emptyset_1 + V_pI_2 \; Cos\emptyset_2 + V_pI_3Cos\emptyset$

V_p = phase voltage $= \frac{V_L}{\sqrt{3}}$.

Fig. 13 : Three wattmeter method for the measurement of power

(b) Measurement of Energy

Induction disc principle

Nearly all AC energy is measured by meters of the Induction type. The principle components of a single - phase Induction meter are shown in fig. 14

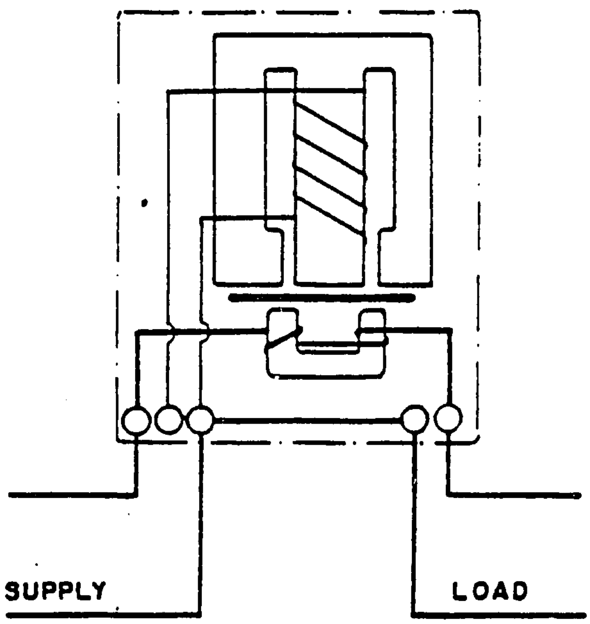


Fig. 14 Single phase induction type watt-hour

The upper electro magnet carries a winding excited by the voltage of the supply and the winding of the lower magnet carries the circuit current.

Torque (T) on the disc is proportional to the real power consumption of the load.

$$T \propto VI\cos\phi$$

The pivoted disc is free to rotate in the gap between these magnets and it is also placed in the field of a permanent magnet (not shown) which provides the eddy current breaking torque. The speed of rotation is proportional to the real power consumption of the connected load. The number of revolution are counted on a register coupled to the disc through a gear mechanism.

The energy consumption (J) in a finite period of T,

$$J = \int_0^T P\,dt$$

is registered on the counter.

<u>Three phase energy meter for unbalanced loads</u>

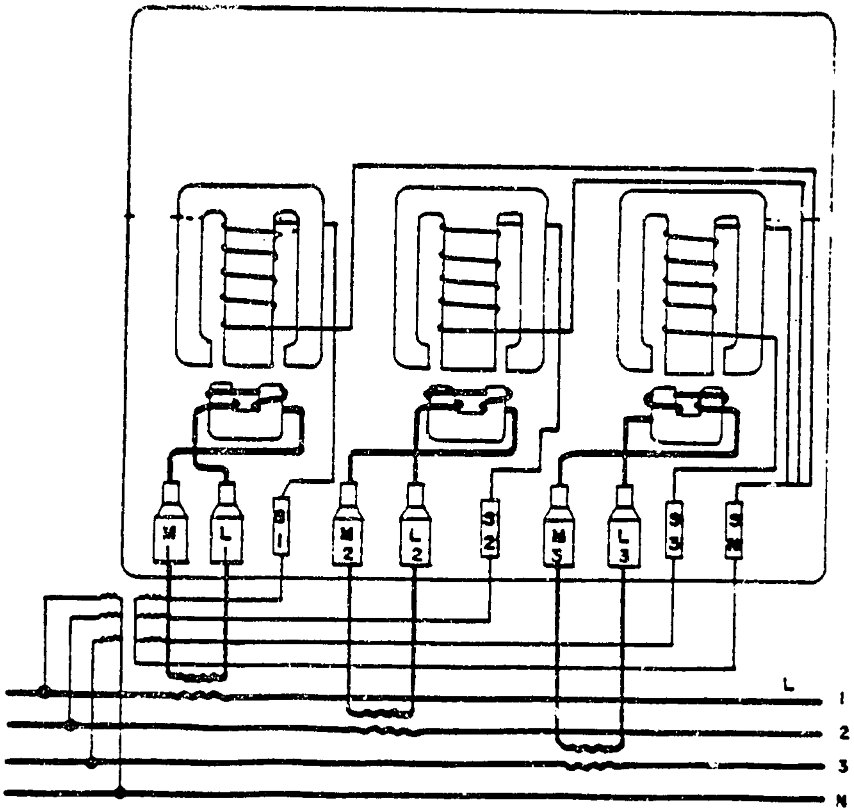


Fig. 15 : Three phase energy meter

The torque contribution from each set of coils is proportional to the real power consumption of each phase.

An induction Watthour meter may be compensated to read Volt-Ampere hours (or KVAh) by suitable adjustment of the flux, and will be indicated on a clock work or a cyclo dial.

(c) Measurement of Demand

Maximum Demand Meters

The kVA demand is integrated for a fixed time and the sustained maximum demand for the integration period is indicated by a pointer.

A typical value for the integration period is 15 minutes and it is timed by a clock work mechanism.

5. Transformers - A single phase transformer

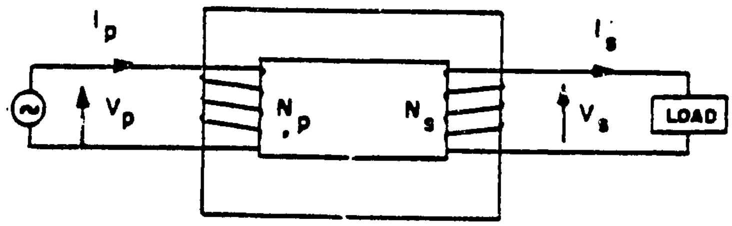


Fig. : 16 (a) Single phase Transformer

V_p = primary voltage

I_p = primary current

V_s = Secondary (load) voltage

I_s = Secondary current

N_p = number of primary turns

N_s = number of secondary turns

N = turns ratio

$$\frac{V_p}{V_s} = \frac{N_p}{N_s}$$

$$\frac{I_p}{I_s} = \frac{N_s}{N_p}$$

$$N = \frac{N_s}{N_p}$$

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Each of the two windings of a transformer has its resistance and inductance which can be considered to be in series as shown.

The basic equivalent circuit of a single phase transformer is shown in figure 16 (b)

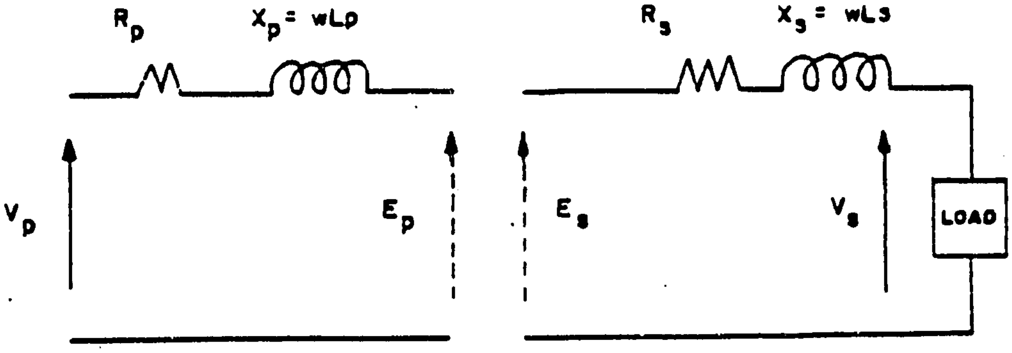


Fig. 16(b) : The basic equivalent circuit of a transformer

The existing or the no load current is a small fraction of load current. The total equivalent circuit may be represented as follows:

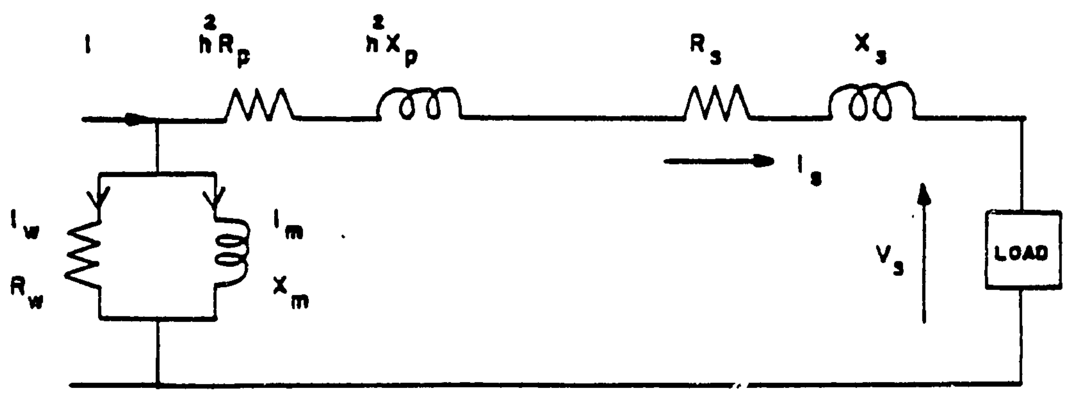


Fig. 16(c) Transformer equivalent circuit referred to the Secondary.

$$n = \frac{N_p}{N_s}$$

The current I comprises three components.

I_s = load current

I_w = component of current representing core loss in the equival resistance R_w

I_m = component of current representing magnetic leakage in the equivalent reactance X_m

(b) Losses in a Transformer

Since the transformer is a static type of machine, friation and windage losses are not present.

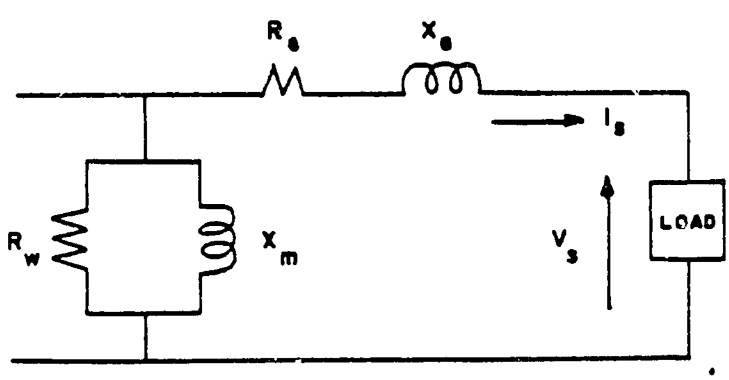
The losses occuring in a loaded transformers may be divided into two components.

(i) Hysteresis and eddy current losses in the core, usually known as the iron losses (W_I). The magnitude of the loss is independent of the load on the transformer

W_I = constant (for operation at rated voltage)

(ii) losses in the winding due to resistance and also to the eddy currents in the conductors, usually known as copper losses (W_{cu}). The copper loss is proportional to the square of the load current.

$$W_{cu} \propto I_s^2$$



$$R_e = h^2 R_p + R_s$$

$$X_e = h^2 X_p + X_s$$

Fig. 16(d). The total equivalent circuit of a single phase transformer.

Total equivalent series impedance referred to the secondary, $Z_e = \sqrt{Re^2 + Xe^2}$

\0\/

The percentage impedance

It has become a common practice to express the equivalent impedance of a transformer as a percentage. The percentage impedance of a transformer is said to be V % if the impedance voltage drop at full load is equal to V % of the no load voltage.

The actual value of the impedance referred to the secondary may be obtained as follows :

$$V\,\% = \frac{I_s Z_s}{V_s} \times 100\,\% \qquad I_s = \text{full load secondary current}$$

$$Z_s = \frac{V.\,V_s}{I_s \times 100} \qquad V_s = \text{no load secondary voltage.}$$

By using values of current and voltage for the primary , the equivalent impedance referred to the primary may be obtained.

Efficiency (η)

With reference to figure 16(d)

$$\eta = \frac{\text{Power output}}{\text{Power output} + \text{Copper loss} + \text{Iron loss}} \times 100$$

$$= \frac{V_s I_s \cos \phi_s}{V_s I_s \cos\phi_s + W_{cu} + W_I} \times 100$$

$$= \frac{V_s \cos \phi_s}{V_s \cos\phi_s + \frac{I_s^2 R_e}{I_s} + \frac{W_I}{I_s}} \times 100 \quad (\cos\phi_s = \text{load power factor})$$

η Is maximum when , $-\frac{W_I}{I_s^2} + R_e = 0$

$$\text{i.e.} \quad W_I = I_s^2 R_e = W_{cu}.$$

Thus the efficiency of a transformer is optimum when the copper loss equals the iron loss.

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6. Electrical Machanes

(A) DC Motors

Direct current machines fall into three major categories according to the field connections with the armature, as indicated on the following diagrams.

V = Supply Voltage

I_a = Armature current

E = back emf

ϕ = flux per pole

τ = torque on shaft

R_a = Armature resistance

R_f = Field resistance

I_f = Field current

N = Rotational speed

$$V = E + I_a(R_a + R_f)$$

$$E \propto N\phi$$

$$\tau \propto I_a^2$$

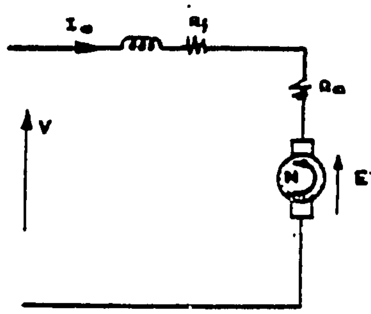


Fig. 17(a) DC Series motor

The following figure gives typical operating characteristice of a 5 HP 220 Volt, 1000 rpm series motor.

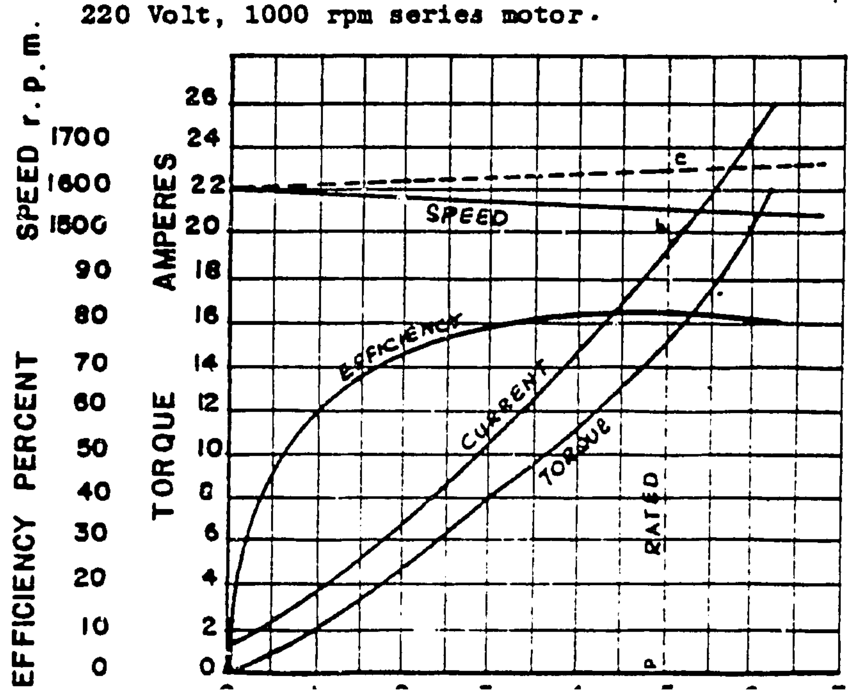


Fig. 17(b) Typical characteristics of a dc series motor

(ii) DC Shunt motor

$$V = E + I_a R_a$$

$$E \propto N\phi$$

$$\tau \propto \phi I_a$$

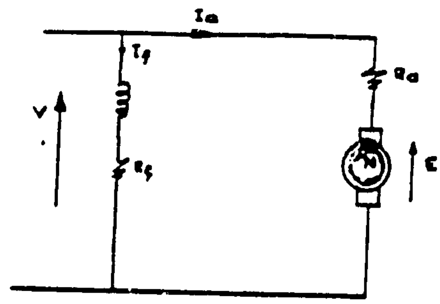


Fig. 18(a) DC Shunt motor

The typical operating characteristics of a 5HP, 230 volt, 19.8 Ampere, 1600 rpm shunt motor is given below.

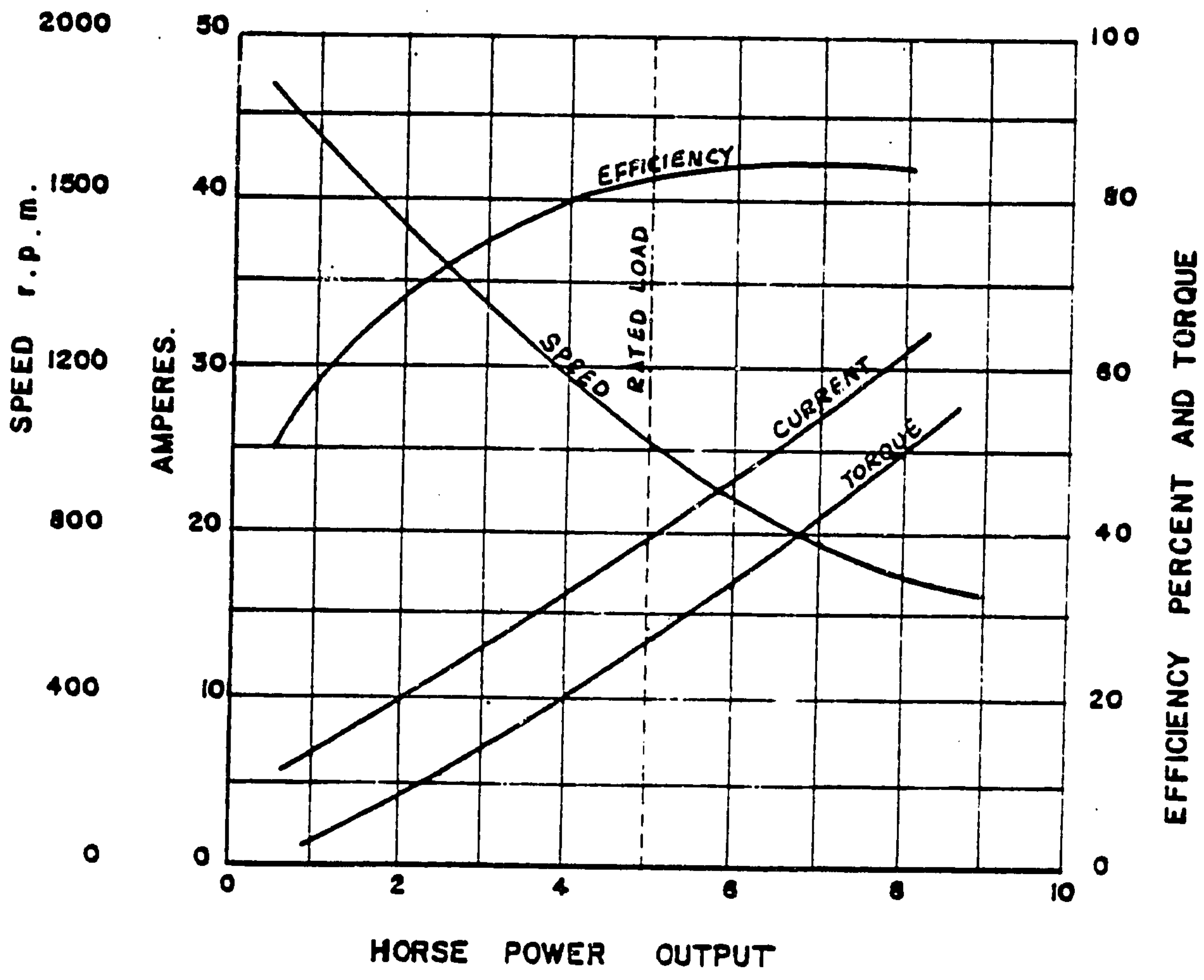


Fig. 18(b) Typical characteristics of a dc shunt motor

(iii) <u>Compound Motor</u>

This has both series and shunt windings which may either be

(i) Cumulative compound (fig. 19(a))
(ii) Differential compound (fig. 19(b))

In the cumulatively compounded motor, the two windings assist each other in producing the flux while in the differentially compounded motor, the fluxes produced oppose each other. The characteristics of compound motors are combinations of series and shunt motors.

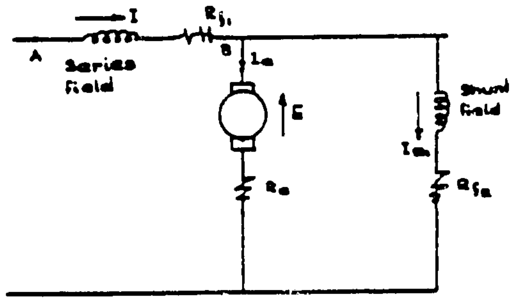


Fig. 19(a) Cumulative compound
DC Motor

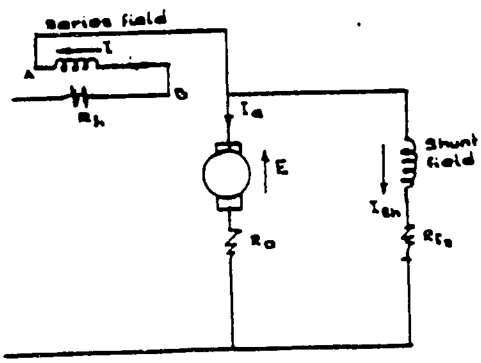


Fig. 19(b) Differential compound
DC Motor

Starting of DC Motors

A series resistance (E_s) is inserted in series with the armature to limit the starting current

Starting resistance $R_s = \frac{V}{I_s} - R_a$ Where V = supply voltage

I_s = armature starting current

R_a = Armature resistance

(B) <u>AC Motors</u>

<u>Induction Motors</u>

The induction motor is the most widely used electro-mechanical energy converting device used in industry. Its ruggedness, efficiency and reliability makes its the work horse of the modern industry.

The two basic designs of induction motors are

(i) Squirrel cage type and

(ii) Wound rotor type for single and three phase operation.

(i) <u>Squirrel cage motors</u>

Typical connection diagrams of the more commonly used single phase squirrel cage type of induction motors are given in figures 20(a) - (d).

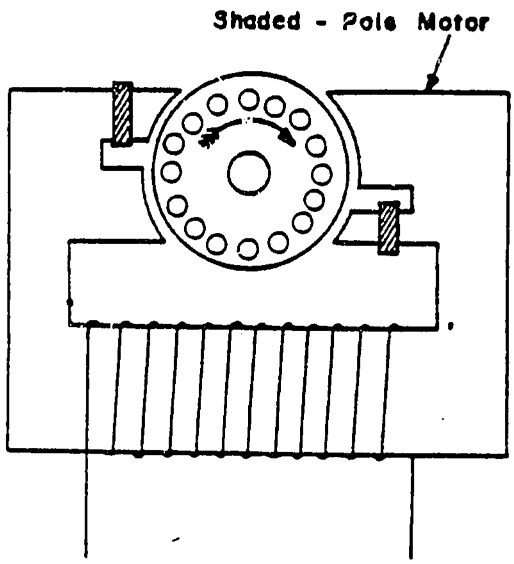


Fig. 20 (a) Shaded pole motor

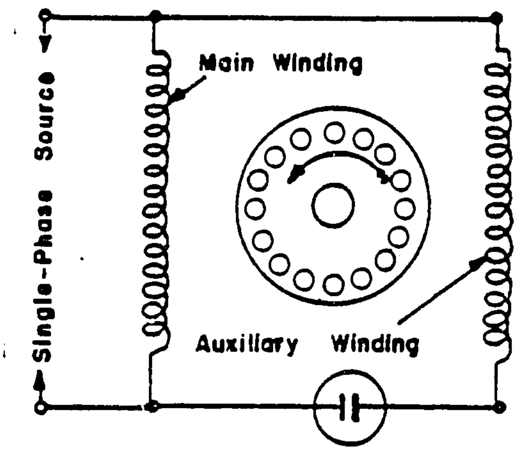
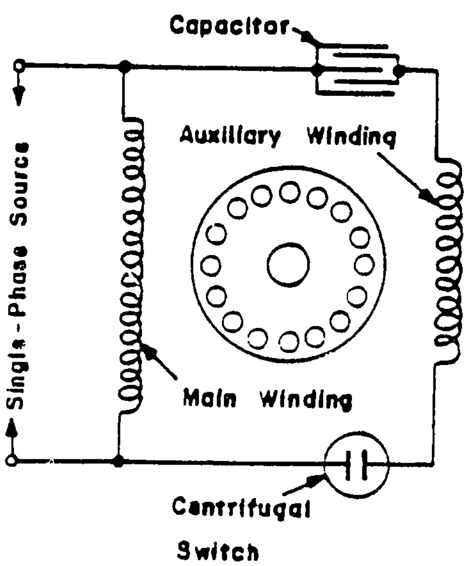


Fig 20 (b) Split phase motor.



. Fig. 20(c) Capacitor Start motor

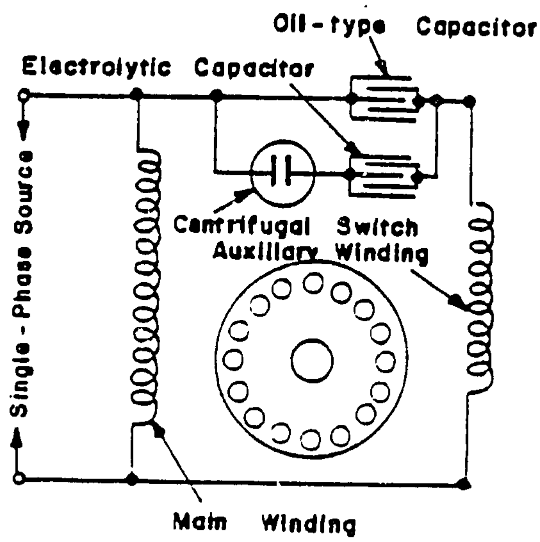


Fig. 20 (d) Capacitor start and run motor.

This classification of single phase squirrel cage type induction motor is based on the method employed to produce the starting torque.

Three phase squirrel cage motors have a distributed three phase winding designed for star or delta connection as required for starting purposes

(ii) <u>Wound rotor motors</u>

Wound rotor types could be broadly divided into two basic groups, namely

(A) Slip ring type

(B) Commutator type

Typical connection diagrams of these two types are given in figures below :

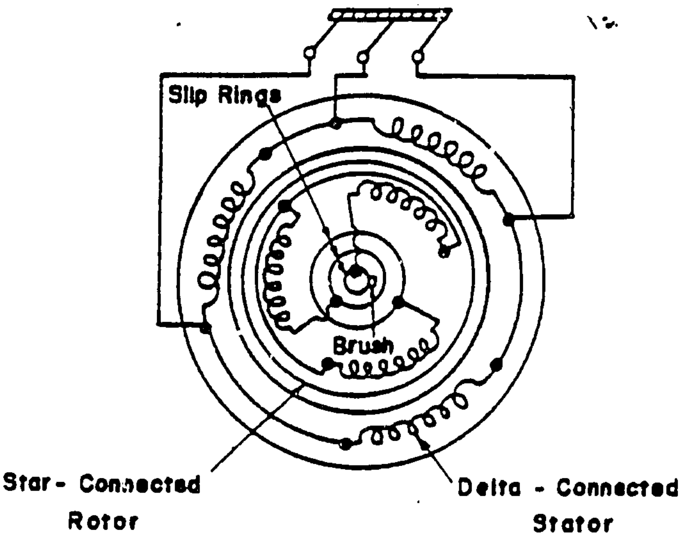


Fig. 21 (a) Slip ring type rotor induction motor

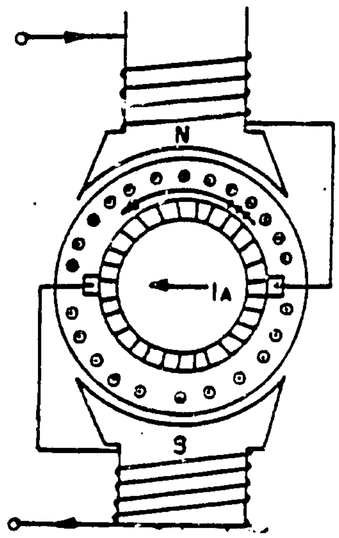


Fig. 21(b) Commutator type single phase AC motor

The equivalent circuit of an induction motor is shown in the following figure.

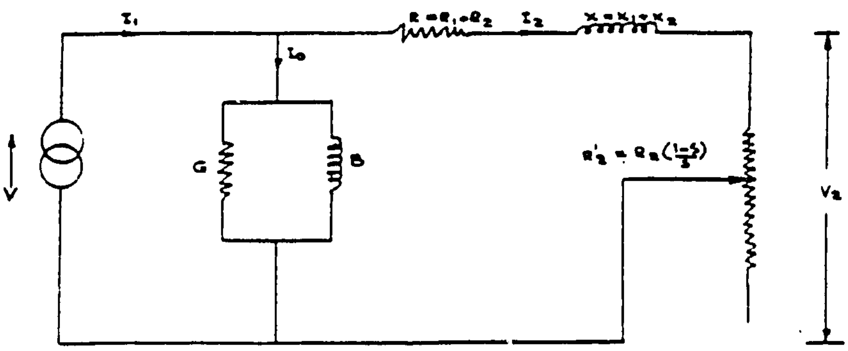


Fig. 22 Equivalent circuit of indution motor

I_1	=	line current
I_o	=	component of current representing the core loss
R	=	total equivalent resistance = $R_1 + R_2$
X	=	total equivalent resistance = $X_1 + X_2$
R_2^1	=	resistance representing the mechanical load on the machine.
S	=	slip of the rotor.
G	=	admittance representing the core loss
B	=	susceptance representing the magnetic leakage.

The synchronous speed (N_s) is defined as

$$N_s = \frac{120f}{p} \text{ rpm where } f = \text{supply frequency}$$

p = number of poles of the motor.

The slip (S) an induction motor is defined as,

$$S = \frac{N_s - N}{N_s}$$ where N is the rotational speed.

Gross power output of the rotor $= \left(\frac{1-S}{S}\right) R_2 \; I_2^2$

The loss in the copper of the rotor $= I_2^2 \; R_2^1$

Total power transferred to the rotor $= \left(\frac{1-S}{S}\right) R_2 I_2^2 + R_2 I_2^2$

$$= \frac{R_2}{S} I_2^2$$

$$\frac{\text{Rotor copper loss}}{\text{gross mechannical output}} = \frac{R_2 I_2^2}{\frac{1-S}{S} R_2 I_2^2} = \frac{S}{S-I}$$

Rotor Efficiency $= \dfrac{\text{gross power output of rotor}}{\text{rotor power input}}$

$$= \frac{1-S}{S} R_2 I_2^2 \; / \; R_2 I_2^2/S$$

$$= 1-S$$

The following graphs depict the typical characteristic of induction motors.

The wound rotor type has a higher starting torque and the torque curve shown in figure will show a higher value at start.

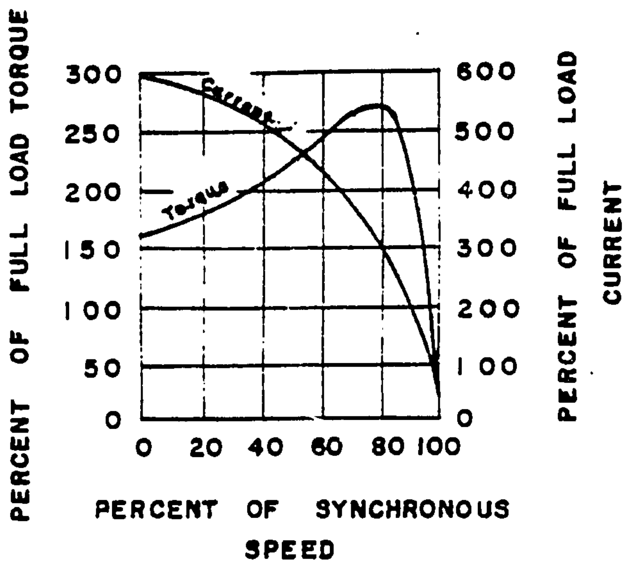


Fig. 23(a) Torque - speed & current-speed characteristics of induction motors

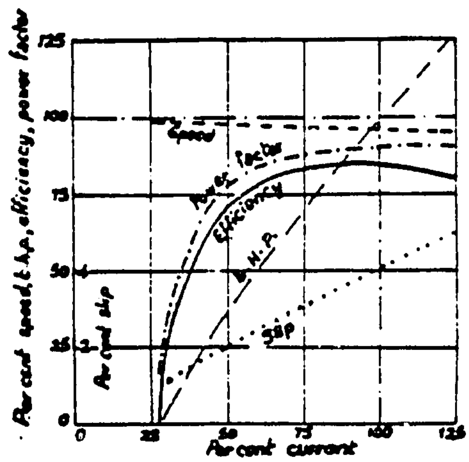


Fig. 23(b) general characteristic of induction motors.

Synchronous Motors

Synchronous motors are constant speed motors used for special applications in industry. The basic arrangement of the field and the startor windings for a revolving field machine are shown in the following figure.

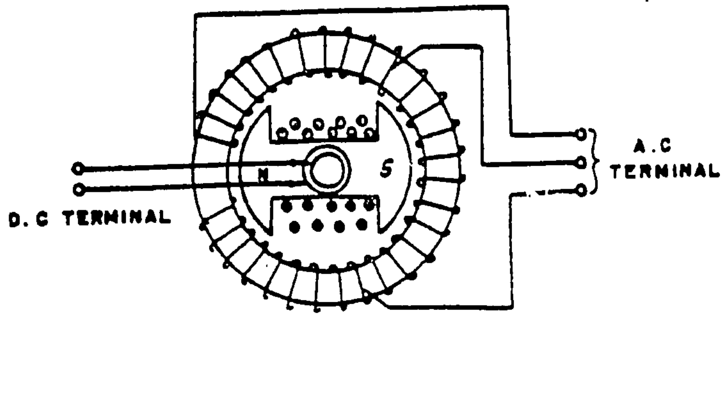


Fig. 24 - Electrical connection diagram of a synchronous motor.

The rotational speed is always the synchronous speed unlike the induction motor which always runs at a speed slightly below the synchronous speed.

Typical performance characteristic, of a synchronous motor are shown in figure 25 . These curves show how the armature current varies when the motor output is kept constant and the field current is increased continuously from very low to very high values. Different curves obtained for different contant loads with varying field current are given in the figure.

V = Phase voltage of supply

I = line current

Ø = power factor

Real power P = 3VICosØ

The current (I) and power factor (CosØ) vary with the field current keeping the product I CosØ constant and thus the real power.

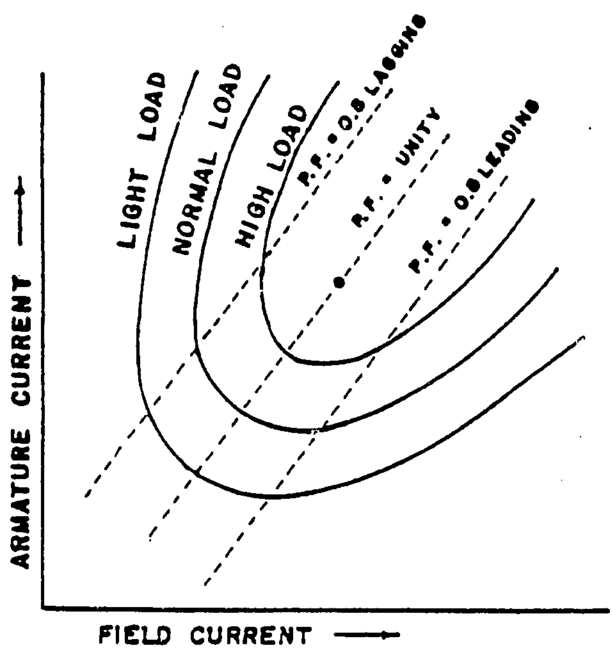


Fig. 25 - Synchronous motor characteristics

A synchronous motor may be called upon to absorb lagging or leading reactive power by adjusting the field current. Thus by over-ex ting a synchronous motor, it may be used as a capacitor (synchronous condenser) absorbing leading reactive power and a certain amount of real power thereby improving the power factor of connected installation.

7. Parameters Related to Industrial Load Management

(a) Diversity Fnctor

The diversity factor is defined as the ratio between the sun of the maximum demands of industrial load centres and the total combined maximum demand of the industrial concern.

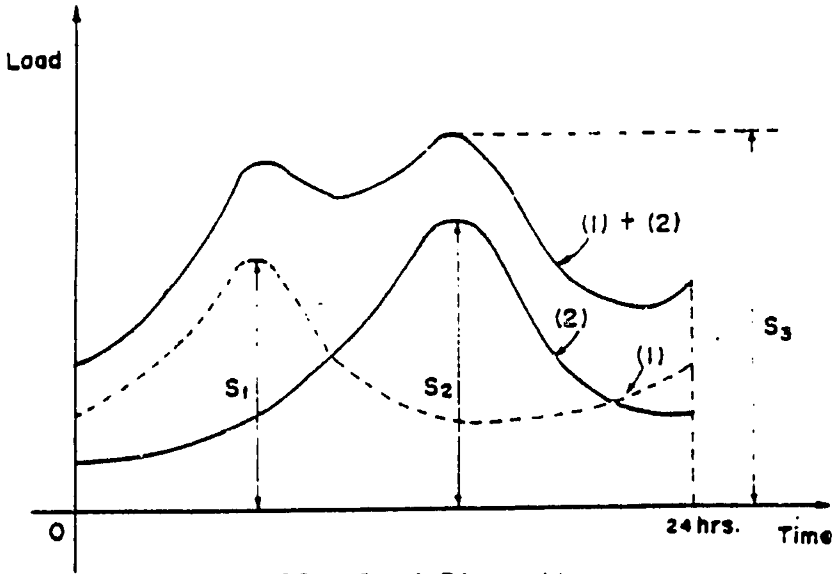


Fig. 26 - Load Diversity

Figure shows the load profiles of two loads and their combined load.

$$\text{Diversity Factor} \qquad D = \frac{S_1 + S_2}{S_3}$$

This factor is always greater than or equal to unity and a high diversity factor is preferred.

(b) Load Factor (L)

The load factor is the ratio between the average load (Lav) and the maximum load (Lmax)

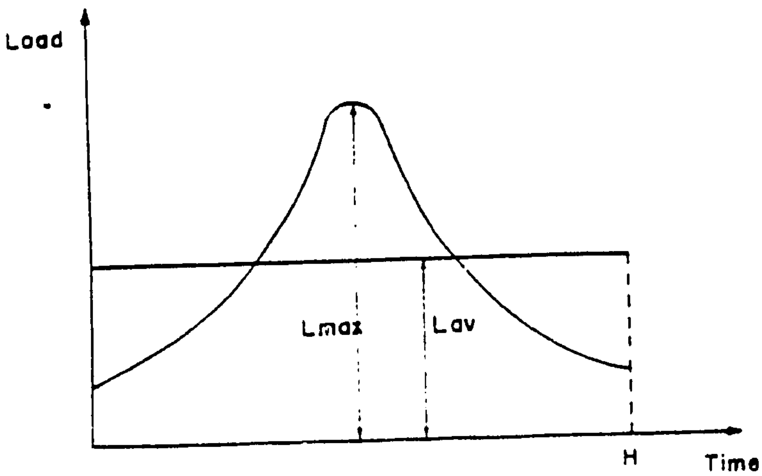


Fig. 27 - Peak and average loads

Refering to the above figure,

L_{max}

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The time H could be selected to be an hour, day, month, year etc. and the load factor be defined with reference to the selected period of time.

A load factor close to unity is preferred.

(c) Utilization Factor (U)

This is defined mainly in relation to generation facilities.

$$\boxed{\text{Utilization Factor, } U = \frac{L_{max}}{L_r}}$$

Lmax	=	maximum demand of the plant
Lr	=	related capacity of the plant

The utilization factor is dependent on the type of plant and its characteristics.

(D) Capacity Factor (C)

This too is defined mainly in relation to generation facilities.

$$\boxed{\text{Capacity factor, } C = \frac{L_{av}}{L_r}}$$

Lav	=	average demand of the plant
Lr	=	rated capacity of the plant

NOTE: Capacity factor = Utilization factor X Load factor

$$\boxed{C = U \times L}$$

SESSION 3: FINANCIAL AND ECONOMIC REFRESHER

This session is designed to give the course participant an introduction to the principles of financial and economic analysis. In this session, the basic tools and methods of financial analysis are provided. Also, a specific procedure is proposed for industrial energy project evaluation, and examples are given. This session concludes with a discussion of social cost/benefit analysis and the importance of national energy planning in the evaluation of specific industrial energy projects. The session is organized in the following manner:

- Concept of Life-Cycle Costing (LCC)
  - cash flow conventions
    - end-of-period flow convention
    - determination of the interest period
  - time value of money concept
    - rates of interest
- Modes of Analysis
  - payback period (simple and discounted)
  - return on investment
  - total life-cycle cost (present value)
  - net life-cycle savings
  - uniform annual cost
  - savings/investment ratio (SIR) or benefit/cost ratio (B/C)
  - net present value
  - internal rate of return
- Sensitivity Analysis of Cost Parameters
- Four-Step Financial Evaluation Procedure
  - selection of inflation rate and time frame
  - evaluation of energy cost savings and indirect benefits

- evaluation of direct project costs and related expenses
- selection of evaluation method

- Major Factors Influencing the Results of the Four-Step Financial Evaluation Approach

  - financing and tax expenses
  - project risk
  - example
  - effect of available financing alternatives

- Appendix 3.A: Glossary of Terms

- Appendix 3.B: Tools of LCC Analysis

  - single compound amount (SCA)
  - single present value (SPV)
  - uniform capital recovery (UCR)
  - uniform present value (UPV)
  - uniform sinking fund (USF)
  - uniform compound amount (UCA)

- Appendix 3.C: Interest Tables.

CONCEPT OF LIFE-CYCLE COSTING (LCC)

When a consumer decides that a certain item in a store is very desirable, the factor that is usually primary in the purchase decision is price, or "first cost." Subsequent costs can be expected to play a minor role. Whether the item is a piece of clothing, a television set, or even a house, anticipated maintenance costs rarely are a significant consideration in the decision-making process. Yet, maintenance costs are a price of ownership just as much as initial costs. A consumer making a capital investment can take on a number of forms, such as an individual, a corporation, or a government agency. Once the capital investment is made, its consequences are often irrevocable.

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Because of this permanence, the analysis of a capital investment decision must be sound and rigorous, leaving little doubt that the information presented is as reasonable and as accurate as the facts allow.

Not only is the permanence of the decision important, but the trend in costs -- **especially energy costs** -- requires that careful thought be given to all aspects of capital investment decisions. This is particularly true for those decisions involving buildings and industrial equipment. For these investments, five components stand out as requiring careful consideration:

1. Initial capital investment costs
2. Annual operating and routine maintenance costs
3. Major repairs and component replacements
4. Complete item or system replacement
5. Residual values.

A sixth consideration is time. The timing factor is used to judge when costs or benefits occur and when replacements are needed. Combining the five elements together results in a "life cycle" for an investment decision.

Life-cycle costing (LCC) is a method of expenditure evaluation that recognizes the sum total of all costs associated with the expenditure during the time that it is used. Initial costs and all subsequent expected costs of significance are included in the calculations, as well as disposal value and any other quantifiable benefits to be derived. The LCC technique is justified whenever a decision must be made on the acquisition of an asset that will require substantial operating and maintenance costs relative to its first cost over its life span.

The LCC method relies on forming a basis of comparison or equivalence among the cash flows of a project. The concept of equivalence is so basic to engineering economics studies that it must be thoroughly understood before making such studies. The concept that payments that differ in total magnitude and are made at different dates may be equivalent to one another is an important one in engineering economics. The meaning of equivalence may be explained by using an analogy from algebra: If a number of things are equal to one thing, then they are equal to each other. Given an interest rate, we may say that any payment or series of payments that will repay a present sum of money with interest at that rate is equal to that present sum. To clarify the concept of equivalence cash flow conventions, interest period conventions, time value of money concepts, and concept of interest should be reviewed.

Cash Flow Conventions

Since engineering economics is largely concerned with the evaluation of different cash flow series, it follows that one must be very specific about when cash flows occur.

End-of-Period Flow Convention

Unless stated otherwise, it will be assumed that all cash flows occur at the ends of interest periods (an interest period is usually a month or a year). One method of employing this convention is to assume that all cash flows during an interest period come at the end of that interest period.

Elapsed time (interest periods)	Cash flow (dollars)
0.2	+60
0.4	-40
0.8	+40
1.2	-48
1.6	+88
1.8	+40
2.1	+40
2.4	+70
2.8	-40

For each of the above interest periods, the end of period cash flows assumed are the sums of the actual cash flows occurring during the respective interest periods.

This procedure for using the convention introduces less error, especially for high interest rates and/or long interest periods. Whichever method you choose, it must be followed consistently throughout the analysis. We suggest using end of period cash flows in all analyses.

Determination of the Interest Period

In many business transactions, interest is computed and charged (or credited) more often than annually. An example of a loan handled this way is one that is stated as 0.9 percent per month on the unpaid balance. This 0.9 percent per month rate equates to a nominal rate of interest per annum of (12 months) x (0.9 percent/month) = 10.8 percent, which equates to an effective annual interest rate of $(1 + .009)^{12} - 1 = .11351$, or 11.351 percent.

Interest rates used in engineering evaluations will be the effective annual rate unless otherwise stated. However, it is sometimes necessary to derive an effective monthly interest rate for very short-term studies.

Time Value of Money Concept

The purpose of analyzing investment opportunities is to measure the productivity of current expenditures against future benefits derived from project implementation. The decision-maker cannot be indifferent to otherwise exactly comparable alternatives in which the timing of benefits varies widely. More immediate benefits are preferable to benefits obtained later in time, even if risk and uncertainty are comparable. If a consumer must wait to obtain a sum of money in benefits derived from an investment, the consumer is losing the opportunity to invest the funds elsewhere during the interim period. Stated another way, money has value distinctly related to the timing of its receipt and disbursement, and this value is determined by the **opportunity to earn** from normal investment activity. This concept is referred to as the opportunity cost, the interest rate, the discount rate, or the hurdle rate. These terms are often used interchangeably.

Studies in engineering economics are concerned with the most economical alternatives in the long run. Since the alternatives to be considered are expressed in terms of money flowing at different times, the time value of money and the changing value of monetary units must be recognized.

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Why are cash flows received in the future considered to have less value than cash flows received now? Four factors come to mind:

1. **Inflation.** A hundred dollars will not buy as much in 10 years. The dollars will likely be worth less then; they will have less purchasing power.
2. **Utility (or time preference).** Even if as much could be bought in 10 years with the dollars to be received, why should the consumption be postponed?
3. **Contingency.** The corporation or individual may not exist 10 years hence.
4. **Opportunity.** A real return can be earned on the money over the 10-year period.

Money, then, has a time value. If $1.00 can be invested today at an 8-percent annual nominal rate, it will be worth $1.08 one year from now. In other words, the present worth of the $1.08 to be received next year is $1.00. The present worth of any amount of money due in the future is calculated by a process known as discounting. In the above illustration, the discounting is performed by dividing the $1.08 by 1.08 (i.e., 1 + rate).

The discounting process is important in LCC analysis because it facilitates the translation of future values to present values. If the total cost of owning an asset is its initial cost and all subsequent costs, the latter must first be discounted to the present value before they are combined with the initial cost to obtain the life-cycle cost. It would be erroneous to ignore the timing of the future costs and merely add them to initial cost.

Rates of Interest

The time value of money and changing value of money are reflected in an **interest** rate. This interest rate exists primarily because there are other things to do with the money, there is a risk of investing it, and it is not worth the same when it is returned. Because of this thing called **interest,** a dollar now is worth **more** than the prospect of a dollar next year. There are two basic ways of thinking of interest:

1. Interest is money paid for the use of money. (This amount is paid by a borrower and received by a lender.)
2. Interest is the return obtainable because of the productive use of capital assets. ("Return" is a short form of "return on investment.")

The **rate of interest** is the ratio between the interest payable or chargeable (or earned) at the end of an interest period and the money owed (or invested) at the beginning of that time period. For example, if $1,000 is borrowed at the beginning of the year and paid back at the end of the year plus $60 interest, the interest rate per annum is:

$$\frac{\$60}{\$1{,}000} = .06, \text{ or 6 percent interest.}$$

Even though interest is frequently payable more often than once a year, the interest rate per annum will be implied in this manual unless stated otherwise.

There are various ways of stating interest rates. For instance, 1/2 percent payable monthly, 1-1/2 percent payable quarterly, and 3 percent payable semiannually are all 6 percent **nominal** annual interest rates. However, each of these rates results in a different **effective** annual interest rate because of the effects of compounding interest. In this manual, we will imply effective annual interest rates unless stated otherwise. "Compounded" means that interest not paid when calculated will itself be charged interest, or that interest received prior to a due date will earn additional interest on itself for the lender.

At this time, it is necessary to discuss the differences between **real** and **nominal** interest rates. Real interest rates do not include the rate of inflation. Nominal interest rates include the effect of inflation. As an approximation, the nominal interest rate equals the real interest rate plus the inflation rate. In the case of very high real or inflation rates, however, it is best to be rigorous. In the case of an 8-percent real rate and a 12-percent inflation rate, the nominal rate is 21 percent, and not 20 percent, as calculated from the equation below:

$$\left(1 + \frac{\text{nominal rate, \%}}{100}\right) = \left(1 + \frac{\text{real rate, \%}}{100}\right) \times \left(1 + \frac{\text{inflation rate, \%}}{100}\right)$$

The difference between real and nominal rates is very important when conducting project evaluations. When projecting the annual operating costs or potential energy savings to be derived from the installation of energy-efficient equipment, it is important to realize if those projections are in real or nominal terms. **Real** cash flows are discounted at **real** interest rates; **nominal** cash flows are discounted at **nominal** interest rates.

When there is difficulty in projecting inflation rates, it is usually best to use **real** cash flows discounted with **real** interest rates.

MODES OF ANALYSIS

There are several different ways of combining the data on cost and savings from a project to evaluate its economic performance. The different measures of economic performance are referred to in the life-cycle cost rules as "modes of analysis."

Analysis

Payback period and return on investment are two modes of analysis frequently used by firms that are not fully consistent with the LCC approach in that they do not take into account all relevant values over the entire study period and discount them to a common time basis. Despite their shortcomings, they can provide a first-level measure of profitability that is -- relatively speaking -- quick, simple, and inexpensive to calculate. Therefore, they may be useful as initial screening devices for eliminating the more obvious uneconomical investments.

The additional six modes of analysis that follow are fully consistent with the LCC approach:

- Total life-cycle cost (present value method)
- Net life-cycle savings

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- Uniform annual cost method
- Savings/investment ratio (benefit/cost ratio method)
- Net present value (NPV)
- Internal rate of return.

Each one of the eight modes of analysis is presented in detail below.

Payback Period

The payback (also known as the payout or the payoff) method determines the number of years required for the invested capital to be offset by resulting benefits. The required number of years is termed the payback, recovery, or break-even period.

The measure is popularly calculated on a before-tax basis and without discounting (i.e., neglecting the opportunity cost of capital). Investment costs are usually defined as first costs, often neglecting salvage value. Benefits are usually defined as the resulting net change in incoming cash flow, or -- in the case of a cost-reducing investment like waste heat recovery -- as the reduction in net outgoing cash flow.

The simple payback period is usually calculated as follows:

$$\text{Simple payback period (SPP)} = \frac{\text{First cost}}{\text{Yearly benefits - yearly costs}}$$

For example, the simple payback period for a furnace recuperator that costs $10,000 to purchase and install, $300 per year on average to operate and maintain, and that is expected to save by preheating combustion air an average of $1,400/year in oil expenses, may be calculated as follows:

$$\text{SPP} = \frac{\$10{,}000}{\$1{,}400 - \$300} = 9.1 \text{ yr.}$$

The disadvantages of the simple payback method that recommend against its use as a sole criterion for investment decisions may be summarized as follows:

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- The method does not give consideration to cash flows beyond the payback period, and thus does not measure the efficiency of an investment over its entire life.
- The neglect of the opportunity cost of capital -- that is, failing to discount costs occurring at different times to a common base for comparison -- results in the use of inaccurate measures of benefits and costs to calculate the payback period, and hence determination of an incorrect payback period.

In short, the simple payback method gives attention to only one attribute of an investment (i.e., the number of years to recover costs) and, as often calculated, does not even provide an accurate measure of this investment recovery time. It is a measure that many firms appear to overemphasize, tending toward shorter and shorter payback requirements. Firms' preference for very short payback to enable them to reinvest in other investment opportunities may in fact lead to a succession of less efficient, short-lived projects.

Despite its limitations, the simple payback period has advantages in that it may provide useful information for evaluating an investment. There are several situations in which the payback method might be particularly appropriate:

- A rapid payback may be a prime criterion for judging an investment when financial resources are available to the investor for only a short period of time.
- The speculative investor who has a very limited time horizon will usually desire rapid recovery of the initial investment.
- Where the expected life of the assets is highly uncertain, determination of the break-even life (i.e., payback period) is helpful in assessing the likelihood of achieving a successful investment.

Discounted payback is a variation of the simple payback period. The discounted payback (DPP) differs from the simple payback (SPP) in that the returns are discounted. Consequently, the criticism of the simple payback that it ignores the time value of money is circumvented.

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Example: Find the discounted payback for an outlay of $10,000 for energy-efficient equipment having a life of 8 years. This equipment will produce constant net annual savings of $3,000. The discount rate is 10 percent per year.

Solution:

Year	Discounted savings	Cumulative discounted savings
1	$3{,}000/1.10 = 2{,}727.27$	2,727.27
2	$3{,}000/1.10^2 = 2{,}479.34$	5,206.61
3	$3{,}000/1.10^3 = 2{,}253.94$	7,460.56
4	$3{,}000/1.10^4 = 2{,}049.04$	9,509.60
5	$3{,}000/1.10^5 = 1{,}862.76$	= 1,862.76

$10,000 - 9,509.60 = $490.40 (remaining capital outlay not yet recovered at the end of year 4)

DPP = 4 + (490.40/1,862.76) = 4.26 years.

Return on Investment

The return on investment (ROI) or return on assets method calculates average annual benefits, net of yearly costs such as **depreciation,** as a percentage of the original book value of the investment.

The calculation is as follows:

Return on Investment (ROI) = (Average Annual Net Benefits/Original Book Value) x 100.

As an example, the calculation of the ROI for an investment in a waste heat economizer is as follows:

Original book value = $15,000
Expected life = 10 years
Annual depreciation, using a straight-line method = $15,000/10 =$1,500

Yearly operation, maintenance, and repair cost = \$250

Expected annual fuel oil savings -- \$5,000

$$\text{ROI} = \frac{\$5{,}000 - (\$1{,}500 + \$250)}{\$15{,}000} \times 100$$

$$= 0.22 \times 100 = 22 \text{ percent.}$$

The return on investment method is subject to the following principal disadvantages and therefore is not recommended as a sole criterion for investment decisions:

- Like the payback method, this method does not take into consideration the timing of cash flows, and thereby may incorrectly state the economic efficiency of projects.
- The calculation is based on an accounting concept, original book value, which is subject to the peculiarities of the firm's accounting practices, and which generally does not include all costs. The method, therefore, results in only a rough approximation of an investment's value.

The advantages of the return on investment method are that it is simple to compute and is a familiar concept in the business community.

Total Life-Cycle Cost (Present Value)

When the total life-cycle cost (present value) method is used, all expenditures -- regardless of when they are incurred -- are compared during a common year (i.e., base year). Future expenditures are properly discounted to reflect their time value. The six basic formulae presented in Appendix 3.B (i.e., single compound amount, or SCA; single present value, or SPV; uniform capital recovery, or UCR; uniform present value, or UPV; uniform sinking fund, or USF; and uniform compound amount, or UCA) must be used to properly discount these future expenditures to their present worth. Once these future expenditures are discounted, they may properly be compared to expenditures incurred "today" or during the "base year." Once this discounting is accomplished, all expenditures are weighted on a common basis and can be added together to obtain a total present worth value.

Example: An HVAC system is expected to cost \$50,000. A one-time replacement is expected after 15 years at a cost of \$20,000. Annual operating costs are to be \$5,000 per year. The system is expected to have a salvage value of \$10,000 after 30 years. Using a 10-percent discount rate, what is the total present value of the system over 30 years?

Solution: (present value = PV)

(Note that cash outflows (expenditures) are expressed in parentheses and that cash inflows (e.g., salvage value) are not.)

PV initial cost	= (\$ 50,000.00)
PV of one-time replacement	
= 20,000 x (PV/F, 15 years, 10%)* = 20,000 x .23939	= (4,787,80)
PV of operating costs = 5,000 x (PV/A, 30 years, 10%)**	
= 5,000 x 9.42691	= (47,134.55)
PV of salvage value = 10,000 x (PV/F, 30 years, 10%)*	
= 10,000 x .05731	= 573.10
Total PV of system	(\$101,349.25)

PV/F = present value of a future current value F (SPW)

PV/A = present value of a series of future uniform annual payments (UPW)

*From SPV formula and tables, Appendix 3.B.

**From UCR formula and tables, Appendix 3.B.

The total life-cycle costs, or present value, can be used to rank projects by showing which one has the least total life-cycle cost. This method can be used only if the benefits of the projects being compared are identical.

Example: Alternative A has an initial cost of \$20,000, an estimated life of 20 years, an annual operating cost of \$2,000, and a salvage value of \$2,000.

Alternative B has an initial cost of \$21,000, an estimated life of 20 years, annual operating cost of \$1,800, and a salvage value of \$2,500. The appropriate interest rate for comparing these alternatives is 9 percent per year. The benefits from Alternative A and Alternative B are identical.

Solution (present value = PV)

Alternative A

PV initial cost	= ($20,000.00)
PV operating costs = 2,000 x (PV/A, 20 years, 9%)*	
= 2,000 x 9.12852	= (18,257.04)
PV salvage = 2,000 x (PV/F, 20 years, 9%)**	
= 2,000 x .17843	= 356.88
Total PV	($37,900.16)

Alternative B

PV initial cost	= ($21,000.00)
PV operating costs = 1,800 x (PV/A, 20 years, 9%)*	
= 1,800 x 9.12852	= (16,431.32)
PV salvage = 2,500 x (PV/F, 20 years, 9%)**	
= 2,500 x .17843	= 446.08
Total PV	($36,985.24)

Differential in favor of B = $914.92 (= $37,900.16 - $36,985.24).

*From UCR formula and tables, Appendix 3.B.
**From SPV formula and tables, Appendix 3.B.

Net Life-Cycle Savings (NS)

The net life-cycle savings is the decrease in the total life-cycle cost (TLCC) of an operation that is attributable to an energy conservation opportunity (ECO). It is found by subtracting the TLCC of the operation with the ECO ($TLCC_W$) from the TLCC without ECO ($TLCC_{WO}$). A positive value can generally be held to mean that the ECO is cost-effective.

General Formulas:

$NS = TLCC_{WO} - TLCC_{W}$

$TLCC_{WO}$ = TLCC without ECO

$TLCC_{W}$ = TLCC with ECO

$NS = \Delta E - (\Delta I - \Delta S + \Delta M + \Delta R)$

ΔE = Reduction in energy costs

ΔI = Differential investment costs

ΔS = Differential salvage values

ΔM = Differential nonfuel operation and maintenance costs

ΔR = Differential replacement costs.

NOTE: All amounts are expressed in present values.

Uniform Annual Cost

This method of calculating LCC reduces each alternative cost to the equivalent base of a unifoım annual cost. By using this method, both "present dollars" are converted to a uniform annual cost while taking into account the "time value" of money at a particular interest rate. The six basic formulae must be used to properly establish these annual costs.

All "present costs" are broken down into equivalent yearly payments throughout the life cycle. All "future costs" spent at any time during the life cycle are also broken down into equivalent yearly payments throughout the life cycle. All the equivalent yearly costs are then added together to establish the total uniform annual cost.

When comparing alternatives, the same choice will be made regardless of whether the present value method or uniform annual cost method is used. The same relative cost advantage will result from either method of calculation.

Example: Consider the HVAC system example used to illustrate the present value method.

Solution:

Annual owning cost = A_1 = \$50,000 x (UCR, 30 years, 10%)*
= \$50,000 x .10608
= (\$5,304)

Annual fuel costs = A_2 = (\$5,000)

Annual replacement cost = A_3

PV replacement cost = \$20,000 x (SPW, 15 years, 10%)*
= \$20,000 x .2394
= \$4,788

A_3 = \$4,788 x (UCR, 30 years, 10%) = \$4,788 x .10608
= (\$507.92)

Annual salvage value = A_4 = \$10,000 x (SPW, 30 years, 10%) x (UCR, 30 years, 10%)*
= \$10,000 x .05731 x .10608
= \$60.80

Annualized cost = $A_1 + A_2 + A_3 + A_4$
= (5,304) + (5,000) + (507.92) + 60.80
= (\$10,751.12).

*See Appendix 3.B, UCR, SPW, and tables.

Savings/Investment Ratio (SIR) or Benefit/Cost Ratio (B/C)

The savings/investment ratio or benefit/cost ratio expresses savings as a proportion of investment or benefits as a proportion of cost where all figures are discounted to either a present value or an annual value equivalent. A savings/investment ratio that is greater than 1.0 indicates that the proposed investment is cost-effective. The savings/investment ratio greater than 1.0 indicates that the project in question will return all capital funds at a rate greater than the discount rate. Accordingly, the greater the value of the SIR or B/C, the more cost-effective the investment opportunity.

Example: What is the B/C ratio of an ECO to install an energy-efficient heat pump at a cost of \$7,000? The estimated energy savings is \$2,000 per year. The useful life of the heat pump is 12 years, and the discount rate is 14 percent.

Solution:

Present value (PV) cost = \$7,000

PV benefits = 2,000 (PV/A, 15 years, 14%)

= 2,000 (5.66028)

= \$11,320.56

$$\text{B/C ratio} = \frac{\text{PV benefits}}{\text{PV costs}} = \frac{11{,}320.56}{7{,}000.00}$$

$$= 1.62.$$

Net Present Value (NPV)

The net present value method discounts all of the cash flows of a project to a base year. These cash flows include, but are not restricted to, equipment costs, maintenance expenses, energy savings, and salvage values. The cash flows are discounted to reflect their time value. Once all of the cash flows are discounted to a base year, the cash flows are weighted on a common basis and may be added together to obtain a total **net present value.** Since the cash flows are both positive (salvage values, energy savings) and negative (equipment and maintenance costs), a net present value indicates an acceptable project if it is positive. A negative NPV indicates that a project should not be considered.

Example: An engineer in the food industry is considering a heat recovery device -- an economizer -- in the flue of one of his company's many ovens. The economizer costs \$20,000, and installation costs are expected to reach \$10,000. Annual operating and maintenance costs are estimated at \$1,000. The system has an expected operating life of 20 years, with a salvage value of \$2,000. Energy savings resulting from the installation of the economizer are projected at \$5,000 per year. Using a discount rate of 10 percent, calculate the NPV of the proposed project.

Solution (present value = PV):

PV initial equipment cost	= ($20,000)
PV installation cost	= (10,000)
PV annual O&M expenses = 1,000 x (PV/A, 20 years, 10%)	= (8,514)
PV salvage value = 2,000 x (PV/F, 20 years, 10%)	= 297
PV energy savings = 5,000 x (PV/A, 20 years, 10%)	= 42,568
Net present value (NPV)	= $ 4,351

The positive net present value indicates that the project should proceed. Note that because there are many ovens in this company that presumably could also benefit from use of an economizer to capture waste heat, the positive NPV for one project can become multiplicative when other similar projects are considered. The NPV method is similar to the total life-cycle cost method presented earlier, but includes the ability to compare projects with varying benefits.

Internal Rate of Return

This method (not to be confused with the ROI method evaluated earlier) calculates the rate of return that an investment is expected to yield. The internal rate of return method expresses each investment alternative in terms of a rate of return (a compound interest rate). 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 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.

Example: Calculate the internal rate of return for a heat exchanger that will cost $10,000, will last 10 years, and will result in fuel savings of $3,000 each year.

Solution:

Find the i that will equate the following: \$10,000 = 3,000 x (PV/A, 10 years, i =?).

To do this, calculate the net present value (NPV) for various i values, selected by visual inspection;

NPV 25%	= (\$3,000) x (3.571) - \$10,000
	= \$10,713 - \$10,000
	= \$713
NPV 30%	= (\$3,000) x (3.092) - \$10,000
	= \$9,276 - \$10,000
	= (\$724).

For i = 25 percent, net present value is positive; for i = 30 percent, net present value is negative. Thus, for some discount rate between 25 and 30 percent, present value benefits are equated to present value costs. To find the rate more exactly, without the benefit of a complete set of discount tables or an adequate calculator, you can interpolate between the two rates as follows:

$$i = 0.25 + (713/713 + 247)\ .05 = 0.275, \text{ or } 27.5 \text{ percent.}$$

To decide whether or not to undertake this investment, it would be necessary for the firm to compare the expected rate of return of 27.5 percent with its minimum required rate of return.

SENSITIVITY ANALYSIS OF COST PARAMETERS

Sensitivity analysis is a technique for evaluating a project when there is considerable uncertainty about the appropriate values to use in performing the evaluation. For example, uncertainty about the life of a project, the quantity of energy it will save, energy costs, and/or its future replacement costs may raise doubts about its cost-effectiveness. To assess the likely range of possible outcomes, several evaluations of the project can be made, based on alternative values of the parameters in question. By evaluating the outcome for upper and lower estimated values of the parameters, such as the minimum and maximum estimated life and the minimum and maximum estimated energy savings, sensitivity analysis can be used to bracket the range of likely outcomes and give a clearer estimate of a project's potential cost-effectiveness.

Thus far, we have discussed the basic tools and methods to perform a financial analysis in the energy management sector. Unfortunately, there are numerous project financial evaluation methods that can give conflicting results and can lead to a certain degree of confusion. Because of this possible confusion, we feel that it is necessary to propose a financial evaluation procedure to be used with all projects. The results of financial evaluation methods depend heavily on price projections, time frame, and financing. A four-step procedure can be followed to integrate these factors and avoid the common pitfalls of industrial energy project evaluation (see Exhibit 3.1).

FOUR-STEP FINANCIAL EVALUATION PROCEDURE

Step 1: Select Inflation Rate and Time Frame

- Use the same method to project inflation rates for all projects

  - use of constant dollars

    advantage: makes projections simpler

    disadvantage: does not reflect "real life"

  - use of current dollars

    advantage: does reflect real life

    disadvantage: results in unreliable inflation projections

- Use a sufficiently long time frame to take into account major maintenance expenditures until full replacement of equipment occurs.

Current Practices

- Use of current dollars based on company's own inflation forecast
- Use of a 5-year time frame
- Replacement cycle time frame, usually 15 or 20 years.

Exhibit 3.1

Basic Steps in Project Evaluation

Step 1: Select Inflation Rate and Time Frame

Step 2: Evaluate Energy Cost Savings and Indirect Benefits

Step 3: Evaluate Direct Project Costs and Related Expenses

Step 4: Select Evaluation Method

Sources of Information

- Inflation: no reliable source available.
- Time frame: data from equipment manufacturer.

Step 2: Evaluate Energy Cost Savings and Indirect Benefits

The major elements of cost savings resulting from project implementation are:

a. The energy cost savings
b. The other benefits.

a. The energy cost savings

- Energy cost savings are expressed as amount multiplied by price, for each type of energy saved.

  The type of energy saved must be identified carefully, since multiple heat sources using various types of energy may be involved.

  The energy savings to be considered are **net energy savings,** since energy conservation equipment frequently uses energy.

  The amount of energy saved per year will depend on many factors, including the expected utilization of the new equipment.

  The price of energy saved depends on:

  - the year in which the energy is saved.
  - the price projection can be based on:
    - company's own projections
    - external projections (e.g., government or industry associations)

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b. The other benefits

- Other benefits can come from multiple origins (see Exhibit 3.2).

- Benefit evaluation is plant-specific.

  Examples:

  - In a glass company, the use of a waste heat recovery system resulted in a significant reduction of the size of required pollution equipment costs, the benefit of which was of roughly the same magnitude as the energy cost savings.
  - In a pulp and paper plant, the use of a high-pressure press significantly reduced the steam requirement for paper drying. In addition, this new system allowed a 5- to 10-percent increase in throughput, which translated into incremental sales that were greater than the energy cost savings.
    - It must be remembered at all times that **the objective of a successful energy management program is not to reduce energy consumption but to increase energy efficiency**; that is, to reduce energy cost **per unit of output**, given a set of economic, environmental, and social cost/benefit constraints.

Step 3: Evaluate Direct Project Costs and Related Expenses

The major components of the additional costs resulting from the project implementation are:

a. The direct project costs
b. The related expenses.

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Exhibit 3.2

Potential Benefits Other Than Energy Savings

- Smaller equipment size

  Example: boiler for a given steam requirement.

- Higher throughput for existing equipment

  Example: high-pressure press in the pulp and paper industry.

- Improved product

  Example: heat recovery can produce more stable temperatures for grain drying.

- Reduced cost of labor

  Example: heat recovery on a metal furnace can lower charge over time.

- Reduced maintenance cost for existing equipment

  Example: the installation of a heat recovery system on an oven improved maintenance practices.

- Pollution abatement

  Example: heat recovery on a glass kiln.

- Revenues from sales of recovered heat

  Example: sales of excess hot water generated from heat recovery on a paper dryer.

a. **Direct project costs**

- Project costs must include:

  - cost of preliminary studies
  - cost of planning
  - cost of engineering and design
  - cost of equipment
  - cost of additional materials
  - cost of installation
  - cost of start-up
  - cost of replacement.

b. **Related expenses**

- A myriad of possible additional expenses must be reviewed (see Exhibit 3.3).
- In some cases, an expense may be so large that the whole project becomes uneconomical. For instance, the shutdown of a major piece of equipment to install a heat recovery system may result in lost sales that exceed in value the expected benefits of the operation (e.g., a press in a paper mill).

Finally, all costs can be integrated in a format that, although it is project-specific, is always basically the same: the costs and benefits in rows, with the net cash flow as bottom line, and the years in columns (see Exhibit 3.4).

In computing the cash flows, well-defined practices regarding financing and tax issues should be followed.

Exhibit 3.3

Types of Examples of Project Expenses

Types of costs	Examples of costs
1. Pre-engineering and planning costs	Engineering consultant's fee; in-house manpower and materials to determine type, size, and location of heat exchanger.
2. Acquisition costs of heat recovery equipment	Purchase and installation costs of recuperator.
3. Acquisition costs of necessary additions to existing equipment	Purchase and installation costs of new controls, burners, stack dampers, and fans to protect the furnace and recuperator from higher temperatures entering the furnace due to preheating of combustion air.
4. Replacement costs	Cost of replacing the inner shell of the recuperator in n years, net of the salvage value of the existing shell.
5. Costs of modification and repair of existing equipment	Cost of repairing furnace doors to overcome greater heat loss resulting from increased pressure due to preheating of combustion air.
6. Space costs	Cost of useful floor space occupied by waste heat steam generator; cost of useful overhead space occupied by evaporator.
7. Costs of production downtime during installation	Loss of output for a week, net of the associated savings in operating costs.
8. Costs of adjustments (debugging)	Lower production; labor costs of debugging.
9. Maintenance costs of new equipment	Costs of servicing the heat exchanger.
10. Property and/or equipment taxes of heat recovery equipment	Additional property tax incurred on capitalized value of recuperator.
11. Change in insurance or hazard costs	Higher insurance rates due to greater fire risks; increased cost of accidents due to more hot spots within a tighter space.

Exhibit 3.4

FINANCIAL ANALYSIS BY TIME PERIOD
BOILER PLANT REHABILITATION #1
All Monetary Values In: Rs(000)

TIME PERIOD	3q/1984	4q/1984	1q/1985	2q/1985	3q/1985	4q/1985	1q/1986	2q/1986	3q/1986	4q/1986
PROJECT REVENUES										
ENERGY SAVED (TONNES OF OIL)	0	0	0	0	0	433	433	433	433	433
PRICE ENERGY SAVED	0.00	0.00	0.00	0.00	0.00	5.51	5.67	5.83	6.00	6.17
VALUE ENERGY SAVED	0	0	0	0	0	2387	2456	2526	2599	2673
ENERGY SOLD ()	0	0	0	0	0	0	0	0	0	0
PRICE ENERGY SOLD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VALUE ENERGY SOLD	0	0	0	0	0	0	0	0	0	0
TOTAL REVENUE	0	0	0	0	0	2387	2456	2526	2599	2673
BEFORE TAX COSTS										
ENERGY USED ()	0	0	0	0	0	0	0	0	0	0
PRICE ENERGY USED	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VALUE ENERGY USED	0	0	0	0	0	0	0	0	0	0
DVL PRD EXPENSE	137	274	562	144	111	0	0	0	0	0
DVL PRD INTEREST	0	99	147	252	277	289	0	0	0	0
INDIRECT DVL COST	0	0	0	0	0	0	0	0	0	0
OPER & MAINT EXPENSE	0	0	0	0	0	76	78	80	82	84
OTHER OPER PRD COST	0	0	0	0	0	0	0	0	0	0
OPER PRD INTEREST	0	0	0	0	0	0	289	289	289	289
DEPRECIATION	0	0	0	0	0	552	552	552	552	552
TOTAL COST	137	373	709	395	387	918	919	921	923	925
TAXABLE INCOME	-137	-373	-709	-395	-387	1469	1536	1605	1676	1748
INCOME TAX	-69	-187	-355	-198	-194	735	768	802	838	874
AFTER TAX OUTLAYS										
DEBT PRINCIPAL	0	0	0	0	0	0	0	0	0	144
EQUITY CONTRIBUTED	1880	919	1995	478	240	0	0	0	0	0
TOTAL AFTER TAX OUTLAYS	1880	919	1995	478	240	0	0	0	0	144
AFTER-TAX CASH FLOW	-1811	-733	-1641	-281	-46	1287	1320	1355	1390	1282
CUMULATIVE CASH FLOW	-1311	-2544	-4185	-4466	-4512	-3225	-1904	-550	340	2122

Step 4: Select Evaluation Method

There are many methods for evaluating the financial attractiveness of a project. All the methods characterize the financial performance of a project by a single number. Ultimately, the method chosen must enable the investor to answer such questions as:

- Is this project financially attractive for my company?
- Is this project better than other projects competing for the same funds?

Using only one method can lead to inaccurate results, because no one method takes into account all dimensions of an investment decision. On the other hand, the use of several methods may lead to conflicting results. For instance, two competing projects may have the same simple payback period but significantly different net present values (see Exhibit 3.5).

A five-step approach using several of the above methods can be employed to select the best project from a broad spectrum of candidates (see Exhibit 3.6). By including all key factors of the investment evaluation, this procedure makes such a selection possible.

MAJOR FACTORS INFLUENCING RESULTS OF FOUR-STEP FINANCIAL EVALUATION APPROACH

In evaluating a project, it is important to remember (1) that the results depend heavily on the way financing and taxes are treated, and (2) that risk must be considered.

Financing and Tax Expenses

In addition to direct project costs and related expenses, financing and tax expenses are of major importance to the project's financial attractiveness.

Exhibit 3.5

Illustrations of Contradicting Results
Using Different Methods

Because payback analysis does not take into account annual cash flows beyond the payback period, SPP and NPV would support the different decisions.

	First cost	Yearly benefits					Simple payback period (years)	Total present value of benefits
		Year 1	Year 2	Year 3	Year 4	Year 5		
Project A	$1,200	720	400	240	0	0	2.33	$1,086.36
Project B	$1,200	320	400	480	320	240	3	$1,198.36

Projects A and B have the same first cost. Project A has a shorter payback period than B, but B generates more benefits over time (discount rate = 15%).

The following illustration shows how different decisions could be supported.

	First cost	Yearly benefits					Simple payback period (years)	Total present value of benefits
		Year 1	Year 2	Year 3	Year 4	Year 5		
Project A	$1,200	320	400	480	320	240	3	$1,198.36
Project B	$800	200	280	320	400	480	3	$1,063.40

Projects A and B have the same payback period. Project B is cheaper to implement than A, but A generates more benefits over time (discount rate = 15%).

Exhibit 3.6

A Suggested Approach to
Select Among Competing Projects

Step 1: Use simple payback to limit number of projects for further evaluation. For example: all projects for which SPP is greater than 5 years are rejected.

Step 2: Compute IRR for projects retained after Step 1. For example: eliminate all projects for which IRR is less than 10%.

Step 3: Compute NPV for projects selected in Step 2. Reject all negative-NPV projects.

Step 4: Evaluate effect of available financing alternatives on most attractive projects identified in Step 3.

Step 5: Determine impact of risks on most attractive projects.

- The financial attractiveness of a project depends on how the project will be financed. Equity financing makes a project more attractive than debt financing.
- The financial attractiveness of the project will also depend on how the company treats depreciation. Accelerated depreciation techniques will produce greater tax savings in early years than straight-line depreciation.
- Fiscal incentives such as tax credits can also affect the project's financial attractiveness.
- Before- and after-tax practices may lead to contradictory results.

Project Risk

The need for risk analysis in project evaluation arises from uncertainty in project technical, economic, and financial performance. For instance:

- The actual cost of equipment installation and maintenance can be significantly different from expectations (e.g., space problems, duct work).
- The amount of usable energy recovered can be lower than total recovered energy (e.g., hot water in a paper mill).
- The price of fuels may escalate differently from the projected escalation.

There are three major approaches to deal with uncertainty:

- The break-even analysis (maximum acceptable value of one factor, such as fuel price)
- The probability analysis (expected value)
- The sensitivity analysis (variation of one factor).

Example

A new heating system for an electronic manufacturing plant is being designed with consideration being given to its future energy use. The design engineer has been asked by the owner of the plant to investigate the economics of adding an energy recovery wheel (heat wheel) to the system in an effort to reduce future energy costs.

The engineer calculates that if the wheel were installed, it would reclaim enough energy from the plant's exhaust air that the conventional heating equipment could be reduced in size. With a reduction in size, the initial cost of the conventional heating equipment will be reduced from \$126,000 to \$120,000. The installed cost of the energy wheel is \$16,000. The energy wheel reduces the energy costs from \$30,000 to \$27,000 per year but costs an additional \$500 per year to maintain. The engineer spent \$1,000 in performing the preliminary studies and designing the heat wheel.

Step 1: Select Inflation Rate and Time Frame

The energy savings and maintenance costs of the wheel are given in dollars of the base year. Rather than assume an inflation rate, it may be best to assume that in <u>**real**</u> terms, the energy and maintenance costs do not change. Consequently, the discount rate used should be a real rate and not a nominal rate. The real discount rate will be assumed to be 12 percent per year, and the life of the equipment is expected to be 20 years.

Step 2: Evaluate Energy Cost Savings and Indirect Benefits

The energy cost savings were stated in the problem to be \$30,000 - \$27,000 = \$3,000 per year, not including the additional \$500 annual maintenance cost. The indirect benefit of installing the heat wheel is the ability to downsize the heating unit from an installed cost of \$126,000 to \$120,000.

Step 3: Evaluate Direct Project Costs and Related Expenses

The cost of the engineering studies has already been incurred, and hence are <u>**sunk costs not to be considered in the project evaluation.**</u> These costs will not change whether or not the project is accepted.

The heating equipment has an installed cost of $126,000 without the wheel and $136,000 ($120,000 + $16,000) with the wheel. We assume that the heat wheel can be installed without disrupting operations, thus avoiding a "hidden" cost.

Step 4: Select Evaluation Method

Our suggested approach to project evaluation in itself uses five evaluation methods. These methods begin with the most simple method -- payback -- and become more complex as the clearly undesirable projects are excluded.

a. Payback period (PP)

	Without wheel	With wheel
Initial cost		
Conventional heating system	$126,000	$120,000
Heat wheel	0	160,000
Total installed cost	$126,000	$136,000
Annual O&M costs		
Energy costs	$30,000	$27,000
Maintenance expenses	0	500
Total O&M costs	$30,000	$27,500

$$\text{Simple payback period (SPP)} = \frac{\text{First Cost}}{\text{Yearly Benefits - Yearly Cost}}$$

$$\text{SPP} = \frac{\$136{,}000 - \$126{,}000}{\$30{,}000 - \$27{,}500}$$

$$\text{SPP} = 4.0 \text{ years.}$$

This first stage in the project evaluation screening process has resulted in a payback period that we will assume is sufficiently short as to warrant further investigation of the project.

b. Internal rate of return (IRR)

The internal rate of return (IRR) of a project is that discount rate that, when applied to the project's cash flows, results in a net present value equal to zero.

($136,000 - $126,000) = ($30,000 - $27,000 + $500) x
(PV/A, IRR, 20 years)

4.0 = (PV/A, IRR, 20 years).

The Compound Interest tables show that the present value factor of a yearly stream of cash flows lasting 20 years is equal to 3.95388 at an interest rate of 25 percent and 4.86958 at an interest rate of 20 percent. By linear interpolation, the internal rate of return of this project is equal to approximately 24.7 percent, which we will assume meets company standards (it is greater than the company's 12-percent discount rate). Remember that these discount rates are real rates, net of inflation.

c. Net present value (NPV)

Using the company's 12-percent discount rate, the cash flows are discounted to the base year, and the sum of the present values is calculated.

Initial cost ($136,000 - $126,000)	= ($10,000)
Energy savings ($3,000 x (PV/A, 12%, 20 years))	= 22,408
Maintenance costs ($500 x (PV/A, 12%, 20 years))	= (3,735)
Net present value (NPV)	$ 8,673

The positive NPV indicates that the project passes the financial criteria of the firm embodied in its discount rate.

Impact of Risks

Even for a relatively simple project such as this one, there is much room for error in the projections. For instance, consider the situation if the installed cost of the heat wheel actually turns out to be $18,000 instead of the projected $16,000, and if the projected annual energy savings of $3,000 are in actuality reduced to $2,000 annually. The financial characteristics of the project change in the following manner:

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- Payback period = 8 years
- IRR = 10.9 percent
- NPV = ($796).

Thus, seemingly slight changes in the cash flows can cause a profitable project to become an unprofitable one. Whenever assumptions concerning energy savings or installation costs are encountered, it is best to consider a range of reasonable values and perform sensitivity analyses.

Perhaps the greatest area of potential risk in project evaluation comes in predicting **the future trend of energy prices.** Since the expected lifetime of much of the equipment involved in energy conservation efforts is often around 20 years, there is need for long-term accuracy in the prediction of the project cash flows. For operating and maintenance costs, such predictions can be made with reasonable accuracy. Energy costs, however, are very difficult to project. Twenty years ago, the world oil price of crude was roughly 10 percent of what it is today. The uncertainty involved in energy prices requires that energy price scenarios be an integral part of each project evaluation.

APPENDIX 3.A: GLOSSARY OF TERMS

Annually Recurring Costs — Those costs that are incurred each year in an equal, constant-dollar amount throughout the Study Period.

Annual Value (Annual Worth) — Project costs or benefits amortized over the Study Period; that is, expressed as an equivalent uniform amount, taking into account the Time Value of Money.

Annual Value (Annual Worth) Factor — The number by which a dollar amount may be multiplied to find its equivalent Annual Value, based on a given Discount Rate and a given period of time.

Base Year — The year in which the life-cycle cost analysis is conducted.

Base-Year Energy Costs — The quantity of energy delivered to the boundary of a facility in the Base Year, multiplied by the base-year price of fuel.

Base-Year Energy Savings — For a given facility, the positive difference between the existing facility's Base-Year Energy Costs before the Energy Conservation Opportunity (ECO) implementation and its estimated Base-Year Energy Costs <u>after</u> the ECO implementation, taking into account all types of energy affected.

Cash Flow — The stream of occurrence of a project's costs and benefits -- expressed for the purpose of this requirement in Constant Dollars.

Constant Dollars — Values expressed in terms of the purchasing power of the dollar at the time the life-cycle cost analysis is conducted; Constant Dollars do not reflect future price Inflation.

Cost-Effective — The condition whereby estimated life-cycle cost reductions (benefits) from an energy conservation project exceed the life-cycle costs of that project, where all Cash Flows are assessed in Constant Dollars over the relevant Study Period and discounted to reflect the Time Value of Money.

Current Dollars — Values expressed in terms of the actual prices of each year, including future price Inflation.

Demand Charge — That portion of the charge for electric service based on the plant and equipment costs associated with supplying the electricity consumed.

Differential Cost — The difference in the cost of two alternatives.

Differential Energy Price Escalation Rate — The expected difference between a general rate of Inflation and the rate of price increase assumed for energy.

Discount Factors — Multiplicative numbers for converting Cash Flows occurring at different times to correspondence at a common time. Discount Factors are obtained by solving Discount Formulas based on one dollar of value and an assumed Discount Rate and time.

Discount Formula — An expression of a mathematical relationship that enables the conversion of dollars at a given point in time to an equivalent amount at some other point in time.

Discount Rate — The rate of interest, reflecting the Time Value of Money, that is used in Discount Formulas, or to select Discount Factors that in turn are used to convert Cash Flows to a common time.

Discounted Payback Period — The time required for the cumulative savings, net of future costs, from an investment to pay back the investment costs, taking into account the Time Value of Money.

Discounting — A technique for converting Cash Flows occurring over time to time-equivalent values, adjusting for the Time Value of Money.

Economic Life — That period of time over which an investment is considered to be the lowest-cost alternative for satisfying a particular need.

Energy Conservation Opportunity — An installation or modification of an installation in a facility that is primarily intended to reduce energy consumption or energy cost.

Inflation — A rise in the general price level, or -- put another way -- a decline in the general purchasing power of the dollar.

Internal Rate of Return — The compound rate of interest that, when used to discount the life-cycle costs and savings of a project, will cause the two to be equal.

Investment Costs — The initial costs of design, engineering, purchase, and installation, exclusive of Sunk Costs, all of which are assumed to occur as a lump sum at the beginning of the Base Year for purposes of making the life-cycle cost analysis.

Life-Cycle Costing (LCC) — A general method of economic evaluation that takes into account all relevant costs of a piece of equipment, system, component, material, or practice over a given period of time, adjusting for differences in the timing of those costs. The LCC method encompasses several different economic evaluation techniques, or Modes of Analysis, including Total Life-Cycle Cost Analysis, Net Benefits or Net Savings Analysis, Savings-to-Investment Ratio Analysis, and Internal-Rate-of-Return Analysis.

Modes of Analysis — The various ways in which cost data of a project can be combined and presented to describe a measure of project cost effectiveness. Some LCC Modes of Analysis used to evaluate projects are Total Life-Cycle Costs (LCC), Net Savings (NS), and Savings-to-Investment Ratio (SIR). An additional mode of analysis (which is not fully consistent with the LCC method) used for evaluation is Simple Payback Period (SPP).

Nonrecurring Costs — Costs that are not uniformly incurred annually over the Study Period.

Nonfuel Operation and Maintenance Costs — Labor and material costs required for routine upkeep, repair, and operation, exclusive of energy cost.

Present Value (Present Worth) — The time-equivalent value of past, present, or future costs as of the beginning of the Base Year.

Present Value (Present Worth) Factor — The number by which a dollar amount may be multiplied to find its equivalent Present Value as of the beginning of the Base Year.

Replacement Costs — Future costs to replace a system or component thereof.

Salvage Value — The residual value, net of any disposal costs, of any systems removed or replaced during the Study Period, or remaining at the end of the Study Period, or recovered through resale at the end of the Study Period.

Savings-to-Investment Ratio (SIR) — The present value of future savings, as a ratio to Investment plus Replacement Costs, net of Salvage Value.

Sensitivity Analysis — Testing the outcome of an evaluation by altering the values of one or more system parameters from the initially assumed values.

Simple Payback Period (SPB) — A measure of the length of time required for the cumulative savings, net of cumulative future costs, from an investment to pay back the Investment Cost, without taking into account the Time Value of Money or the Differential Energy Price Escalation Rate.

Study Period — The time period covered by a life-cycle cost analysis.

Sunk Costs — Costs that have been incurred prior to the life-cycle cost analysis and that therefore should not be considered in making a current investment decision.

Time Value of Money — The time-dependent value of money that may stem both from price inflation and from the real earning potential of investments over time.

Total Life-Cycle Cost (TLCC) — The total cost of owning, operating, and maintaining a system over the Study Period.

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Useful Life — The time over which an investment continues to generate benefits or savings.

APPENDIX 3.B: TOOLS OF LCC ANALYSIS

Money has a time value. If \$1.00 can be invested today at an 8-percent nominal annual rate, it will be worth \$1.08 one year from now. In other words, the present worth of the \$1.00 to be received next year is \$0.92. The present worth of any amount of money due in the future is calculated by a process known as **discounting.** In the above illustration, the discounting is performed by dividing the \$1.00 by 1.08 (i.e., 1 + rate).

The discounting process is important in LCC analysis because it facilitates the translation of future values to present values, which makes investment decisions simpler. If the total cost of owning an asset is its initial cost and all subsequent costs, the latter must first be discounted to the present value before they are combined with the initial cost to obtain the life-cycle cost. It would be erroneous to ignore the timing of the future costs and merely add them to initial cost.

All LCC analysis must be performed in terms of compatible dollars (i.e., dollars dated as of a point in time or a period of time). The tools of LCC analysis by which dollar values are shifted in time are six basic interest formulae. These formulae are explained below, and the symbols used are:

- i = an interest or discount rate for the period being considered
- n = number of interest or discount periods
- PV = a present sum of money, or the present value of a sum of money occurring at some other time
- FV = a future sum of money, or the future value of a sum of money occurring at some other time
- A = an end-of-period payment (or savings or receipt) in a uniform series over n periods, or the uniform time-equivalent of a sum of money occurring at some other time.

The various symbols are chosen so that each is an initial letter of a key word associated with the most common meaning of the symbol. Thus, **i** applies to **interest,** **n** applies to **number** of periods, **PV** applies to **present value,** **FV** applies to **future value,** and **A** applies to **annual** payment or **annuity.**

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Formulae The interest factors single compound amount (<u>SCA</u>), single present worth (<u>SPW</u>), uniform capital recovery (<u>UCR</u>), uniform sinking fund (<u>USF</u>), uniform present value (<u>UPV</u>), and uniform compound amount (<u>UCA</u>) can be found in Series A Compound Interest tables (attached).

<u>Single Compound Amount (SCA)</u>

$$SCA = (1 + i)^n.$$

This factor is used to determine the future amount FV that a present sum PV will accumulate at i percent interest, in n years. If you know PV (present value) and want to find FV (future value), then:

$$PV \times SCA = FV.$$

Example: Suppose you deposited \$800 in a savings account that paid interest at the rate of 8 percent per annum, compounded annually. How much money would you have in the account at the end of 3 years, if you made no further deposits or withdrawals? The answer to this question is found by compounding the interest on the principal amount each year for 3 years. The result is called the "future value of a single sum." By carrying out the arithmetic, we find that the future value in 3 years of \$800 deposited today at 8 percent per annum, compounded annually, is 1,007.77.

$$\begin{aligned} FV &= PV \times SCA \\ &= \$800 \times 1.25971 \\ &= \$1{,}007.77. \end{aligned}$$

<u>Single Present Value (SPV)</u>

$$SPV = 1/(1 + i)^n = 1/SCA.$$

This factor is used to determine the present value PV that a future amount FV will be at interest of i-percent, in n years. If you know FV (future value) and want to find PV (present value), then:

$$PV = SPV \times FV.$$

Example: How much money would have to be deposited in a savings account today to receive \$1,007.77 at the end of 3 years, if the account paid interest of 8 percent per annum, compounded annually? The solution is to find the "present value of a single sum." The present value of \$1,007.77 in 3 years at interest of 8 percent per annum, compounded annually, is \$800.

$$\begin{aligned} PV &= SPV \times FV \\ &= 0.79383 \times \$1,007.77 \\ &= \$800. \end{aligned}$$

Uniform Capital Recovery (UCR)

$$UCR = i(1 + i)^n/((1 + i)^{n-1} - 1).$$

This factor is used to determine an annual payment A required to pay off a present amount PV at i-percent interest, for n years. If you know a present sum of money, PV spent today, and want to know the uniform payment A needed to pay back PV over a stated period of time, then:

$$PV \times UCR = A.$$

Example: Suppose you take out a \$800, 3-year loan on your business, paying 8 percent interest, compounded annually. The UCR factor will tell you how much your annual loan payment would be. In this case, the annual loan payment would be \$310.43 (and not \$1,007.77/3 = \$335.92).

$$A = PV \times UCR$$
$$= \$800 \times 0.38803$$
$$= \$310.43.$$

<u>**Uniform Present Value (UPV)**</u>

$$UPV = ((1 + i)^{n-1} - 1)/i(1 + i)^n = 1/UCR.$$

This factor is used to determine the present amount P that can be paid by equal payments of A (uniform annual payment) at i-percent interest, for n years. If you know A (uniform annual payment) and want to find PV (present value of all these payments), then:

$$PV = UPV \times A.$$

<u>**Example:**</u> What single sum, deposited today at 8 percent interest compounded annually, would enable you to withdraw $310.43 at the end of each of the next 3 years? In other words, we are looking for the "present value of a future annuity." The present value of a 3-year annuity of $310.43 at interest of 8 percent compounded annually is $800.

$$PV = UPV \times A$$
$$= 2.57709 \times \$310.43$$
$$= \$800.$$

<u>**Uniform Sinking Fund (USF)**</u>

$$USF = i/(1 + i)^{n-1}.$$

This factor is used to determine the equal annual amount A that must be invested for n years at i percent interest to accumulate a specified future amount FV. If you know FV (the future value of a series of annual payments) and want to find A (value of those annual payments), then:

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$$A = FV \times USF.$$

Example: The future value of a 3-year annuity of \$310.43 earning interest at 8 percent compounded annually is \$1,007.77. That is, to have \$1,007.77 at the end of 3 years, you will have to deposit \$310.43 on December 31 of each of the next 3 years in a sinking fund earning 8 percent interest, compounded annually.

$$\begin{aligned} A &= FV \times USF \\ &= \$1{,}007.77 \times 0.30803 \\ &= \$310.43. \end{aligned}$$

Uniform Compound Amount (UCA)

$$UCA = (1 + i)^{n-1}/i.$$

This factor is used to determine the amount FV that an equal annual payment A will accumulate to in n years at i-percent interest. If you know A (uniform annual payment) and want to find FV (the future value of these payments), then:

$$A \times UCA = FV.$$

Example: If you were to deposit \$310.43 on the last day of each of 3 years in a savings account earning interest at 8 percent per annum compounded annually, how much would you have at the end of the 3 years, or what would be the "future value of the annuity"? The future value of a 3-year annuity of \$310.43 per year at interest of 8 percent per annum compounded annually is \$1,007.77. The word "annuity" is used to describe a series of equal payments, made at regular intervals of time.

$$\begin{aligned} FV &= A \times UCA \\ &= \$310.43 \times 3.2464 \\ &= \$1{,}007.77. \end{aligned}$$

APPENDIX 3.C: INTEREST TABLES

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2.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITAL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.02000	0.98039	1.02002	0.98037	1.00002	0.9999
2	1.04040	0.96117	0.51507	1.94150	0.49507	2.0199
3	1.06121	0.94232	0.34677	2.88379	0.32677	3.0602
4	1.08243	0.92385	0.26263	3.80763	0.24263	4.1214
5	1.10408	0.90573	0.21216	4.71332	0.19216	5.2038
6	1.12616	0.88797	0.17853	5.60129	0.15853	6.3079
7	1.14868	0.87056	0.15452	6.47184	0.13452	7.4340
8	1.17165	0.85349	0.13651	7.32531	0.11651	8.5827
9	1.19509	0.83676	0.12252	8.16203	0.10252	9.7543
10	1.21899	0.82035	0.11133	8.98238	0.09133	10.9494
11	1.24337	0.80427	0.10218	9.78662	0.08218	12.1683
12	1.26823	0.78850	0.09456	10.57511	0.07456	13.4117
13	1.29360	0.77304	0.08812	11.34812	0.06812	14.6799
14	1.31947	0.75788	0.08260	12.10599	0.06260	15.9734
15	1.34586	0.74302	0.07783	12.84898	0.05783	17.2928
16	1.37277	0.72845	0.07365	13.57741	0.05365	18.6387
17	1.40023	0.71417	0.06997	14.29157	0.04997	20.0114
18	1.42823	0.70017	0.06670	14.99172	0.04670	21.4116
19	1.45680	0.68644	0.06378	15.67815	0.04378	22.8398
20	1.48593	0.67298	0.06116	16.35109	0.04116	24.2966
21	1.51565	0.65978	0.05879	17.01086	0.03879	25.7825
22	1.54596	0.64685	0.05663	17.65768	0.03663	27.2981
23	1.57688	0.63416	0.05467	18.29184	0.03467	28.8440
24	1.60842	0.62173	0.05287	18.91356	0.03287	30.4209
25	1.64059	0.60954	0.05122	19.52307	0.03122	32.0293
26	1.67340	0.59759	0.04970	20.12064	0.02970	33.6698
27	1.70686	0.58587	0.04829	20.70650	0.02829	35.3431
28	1.74100	0.57438	0.04699	21.28087	0.02699	37.0500
29	1.77582	0.56312	0.04578	21.84396	0.02578	38.7909
30	1.81133	0.55208	0.04465	22.39604	0.02465	40.5667
31	1.84756	0.54125	0.04360	22.93729	0.02360	42.3780
32	1.88451	0.53064	0.04261	23.46791	0.02261	44.2255
33	1.92220	0.52024	0.04169	23.98813	0.02169	46.1100
34	1.96064	0.51004	0.04082	24.49815	0.02082	48.0321
35	1.99986	0.50004	0.04000	24.99818	0.02000	49.9927
36	2.03985	0.49023	0.03923	25.48840	0.01923	51.9925
37	2.08065	0.48062	0.03851	25.96901	0.01851	54.0323
38	2.12226	0.47120	0.03782	26.44020	0.01782	56.1129
39	2.16470	0.46196	0.03717	26.90215	0.01717	58.2351
40	2.20800	0.45290	0.03656	27.35503	0.01656	60.3998

3.00% COMPOUND INTEREST FACTORS

	SINGLE PAYMENT		UNIFORM SERIES			
PERIODS	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.03000	0.97087	1.03001	0.97087	1.00001	0.9999
2	1.06090	0.94260	0.52262	1.91343	0.49262	2.0299
3	1.09273	0.91514	0.35353	2.82858	0.32353	3.0908
4	1.12551	0.88849	0.26903	3.71706	0.23903	4.1835
5	1.15927	0.86261	0.21836	4.57966	0.18836	5.3090
6	1.19405	0.83749	0.18460	5.41714	0.15460	6.4683
7	1.22987	0.81309	0.16051	6.23022	0.13051	7.6623
8	1.26677	0.78941	0.14246	7.01962	0.11246	8.8922
9	1.30477	0.76642	0.12844	7.78604	0.09844	10.1589
10	1.34391	0.74410	0.11723	8.53013	0.08723	11.4637
11	1.38423	0.72242	0.10808	9.25255	0.07808	12.8076
12	1.42576	0.70138	0.10046	9.95392	0.07046	14.1918
13	1.46853	0.68095	0.09403	10.63488	0.06403	15.6176
14	1.51258	0.66112	0.08853	11.29599	0.05853	17.0861
15	1.55796	0.64186	0.08377	11.93784	0.05377	18.5986
16	1.60470	0.62317	0.07961	12.56101	0.04961	20.1566
17	1.65284	0.60502	0.07595	13.16603	0.04595	21.7613
18	1.70243	0.58740	0.07271	13.75343	0.04271	23.4141
19	1.75350	0.57029	0.06981	14.32371	0.03981	25.1165
20	1.80610	0.55368	0.06722	14.87739	0.03722	26.8700
21	1.86028	0.53755	0.06487	15.41492	0.03487	28.6761
22	1.91609	0.52190	0.06275	15.93682	0.03275	30.5363
23	1.97357	0.50669	0.06081	16.44350	0.03081	32.4524
24	2.03278	0.49194	0.05905	16.93542	0.02905	34.4260
25	2.09376	0.47761	0.05743	17.41304	0.02743	36.4588
26	2.15658	0.46370	0.05594	17.87674	0.02594	38.5525
27	2.22127	0.45019	0.05456	18.32692	0.02456	40.7091
28	2.28791	0.43708	0.05329	18.76399	0.02329	42.9303
29	2.35655	0.42435	0.05211	19.18834	0.02211	45.2182
30	2.42724	0.41199	0.05102	19.60033	0.02102	47.5747
31	2.50006	0.39999	0.05000	20.00032	0.02000	50.0020
32	2.57506	0.38834	0.04905	20.38866	0.01905	52.5020
33	2.65231	0.37703	0.04816	20.76569	0.01816	55.0770
34	2.73188	0.36605	0.04732	21.13173	0.01732	57.7293
35	2.81384	0.35539	0.04654	21.48711	0.01654	60.4612
36	2.89825	0.34504	0.04580	21.83214	0.01580	63.2750
37	2.98520	0.33499	0.04511	22.16713	0.01511	66.1732
38	3.07475	0.32523	0.04446	22.49236	0.01446	69.1584
39	3.16699	0.31576	0.04384	22.80811	0.01384	72.2331
40	3.26200	0.30656	0.04326	23.11467	0.01326	75.4001

4.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.04000	0.96154	1.04000	0.96154	1.00000	1.0000
2	1.08160	0.92456	0.53020	1.88608	0.49020	2.0399
3	1.12486	0.88900	0.36035	2.77508	0.32035	3.1215
4	1.16986	0.85480	0.27549	3.62988	0.23549	4.2464
5	1.21665	0.82193	0.22463	4.45181	0.18463	5.4163
6	1.26532	0.79032	0.19076	5.24212	0.15076	6.6329
7	1.31593	0.75992	0.16661	6.00205	0.12661	7.8982
8	1.36857	0.73069	0.14853	6.73274	0.10853	9.2142
9	1.42331	0.70259	0.13449	7.43532	0.09449	10.5827
10	1.48024	0.67556	0.12329	8.11089	0.08329	12.0061
11	1.53945	0.64958	0.11415	8.76046	0.07415	13.4863
12	1.60103	0.62460	0.10655	9.38508	0.06655	15.0257
13	1.66507	0.60057	0.10014	9.98564	0.06014	16.6268
14	1.73168	0.57748	0.09467	10.56312	0.05467	18.2918
15	1.80094	0.55526	0.08994	11.11839	0.04994	20.0235
16	1.87298	0.53391	0.08582	11.65230	0.04582	21.8244
17	1.94790	0.51337	0.08220	12.16567	0.04220	23.6974
18	2.02582	0.49363	0.07899	12.65930	0.03899	25.6453
19	2.10685	0.47464	0.07614	13.13394	0.03614	27.6711
20	2.19112	0.45639	0.07358	13.59033	0.03358	29.7780
21	2.27877	0.43883	0.07128	14.02916	0.03128	31.9691
22	2.36992	0.42196	0.06920	14.45112	0.02920	34.2478
23	2.46471	0.40573	0.06731	14.85685	0.02731	36.6178
24	2.56330	0.39012	0.06559	15.24695	0.02559	39.0825
25	2.66583	0.37512	0.06401	15.62209	0.02401	41.6458
26	2.77247	0.36069	0.06257	15.98278	0.02257	44.3116
27	2.88337	0.34682	0.06124	16.32957	0.02124	47.0841
28	2.99870	0.33348	0.06001	16.66306	0.02001	49.9675
29	3.11865	0.32065	0.05888	16.98370	0.01888	52.9661
30	3.24339	0.30832	0.05783	17.29202	0.01783	56.0848
31	3.37313	0.29646	0.05686	17.58849	0.01686	59.3282
32	3.50805	0.28506	0.05595	17.87354	0.01595	62.7013
33	3.64838	0.27409	0.05510	18.14764	0.01510	66.2094
34	3.79431	0.26355	0.05431	18.41118	0.01431	69.8576
35	3.94608	0.25342	0.05358	18.66460	0.01358	73.6520
36	4.10393	0.24367	0.05289	18.90826	0.01289	77.5981
37	4.26808	0.23430	0.05224	19.14256	0.01224	81.7021
38	4.43881	0.22529	0.05163	19.36786	0.01163	85.9701
39	4.61636	0.21662	0.05106	19.58447	0.01106	90.4089
40	4.80101	0.20829	0.05052	19.79276	0.01052	95.0253

5.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.05000	0.95238	1.05001	0.95237	1.00002	0.9999
2	1.10250	0.90703	0.53781	1.85938	0.48781	2.0499
3	1.15762	0.86384	0.36721	2.72321	0.31721	3.1524
4	1.21550	0.82271	0.28202	3.54589	0.23202	4.3100
5	1.27628	0.78353	0.23098	4.32942	0.18098	5.5255
6	1.34009	0.74622	0.19702	5.07563	0.14702	6.8018
7	1.40709	0.71069	0.17282	5.78630	0.12282	8.1418
8	1.47745	0.67684	0.15472	6.46313	0.10472	9.5489
9	1.55132	0.64461	0.14069	7.10773	0.09069	11.0263
10	1.62888	0.61392	0.12951	7.72165	0.07951	12.5776
11	1.71033	0.58468	0.12039	8.30632	0.07039	14.2065
12	1.79584	0.55684	0.11283	8.86315	0.06283	15.9168
13	1.88563	0.53033	0.10646	9.39347	0.05646	17.7126
14	1.97991	0.50507	0.10102	9.89854	0.05103	19.5982
15	2.07891	0.48102	0.09634	10.37956	0.04634	21.5780
16	2.18285	0.45812	0.09227	10.83767	0.04227	23.6569
17	2.29199	0.43630	0.08870	11.27396	0.03870	25.8397
18	2.40659	0.41553	0.08555	11.68948	0.03555	28.1317
19	2.52691	0.39574	0.08275	12.08522	0.03275	30.5382
20	2.65326	0.37690	0.08024	12.46210	0.03024	33.0651
21	2.78592	0.35895	0.07800	12.82105	0.02800	35.7183
22	2.92521	0.34186	0.07597	13.16290	0.02597	38.5042
23	3.07147	0.32558	0.07414	13.48847	0.02414	41.4294
24	3.22504	0.31007	0.07247	13.79854	0.02247	44.5008
25	3.38629	0.29531	0.07095	14.09385	0.02095	47.7258
26	3.55560	0.28125	0.06956	14.37508	0.01956	51.1120
27	3.73338	0.26785	0.06829	14.64293	0.01829	54.6676
28	3.92005	0.25510	0.06712	14.89802	0.01712	58.4009
29	4.11605	0.24295	0.06605	15.14098	0.01605	62.3209
30	4.32185	0.23138	0.06505	15.37237	0.01505	66.4369
31	4.53794	0.22036	0.06413	15.59272	0.01413	70.7587
32	4.76483	0.20987	0.06328	15.80259	0.01328	75.2966
33	5.00307	0.19988	0.06249	16.00244	0.01249	80.0613
34	5.25322	0.19036	0.06176	16.19281	0.01176	85.0643
35	5.51587	0.18129	0.06107	16.37410	0.01107	90.3174
36	5.79166	0.17266	0.06043	16.54675	0.01043	95.8332
37	6.08124	0.16444	0.05984	16.71120	0.00984	101.6248
38	6.38530	0.15661	0.05928	16.86780	0.00928	107.7060
39	6.70456	0.14915	0.05876	17.01695	0.00876	114.0912
40	7.03978	0.14205	0.05828	17.15900	0.00828	120.7956

6.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.06000	0.94340	1.06001	0.94339	1.00001	0.9999
2	1.12360	0.89000	0.54544	1.83337	0.48544	2.0599
3	1.19101	0.83962	0.37411	2.67298	0.31411	3.1835
4	1.26247	0.79210	0.28859	3.46508	0.22859	4.3745
5	1.33822	0.74726	0.23740	4.21233	0.17740	5.6370
6	1.41851	0.70496	0.20336	4.91728	0.14336	6.9752
7	1.50362	0.66506	0.17914	5.58234	0.11914	8.3937
8	1.59384	0.62741	0.16104	6.20975	0.10104	9.8973
9	1.68947	0.59190	0.14702	6.80165	0.08702	11.4911
10	1.79084	0.55840	0.13587	7.36004	0.07587	13.1806
11	1.89829	0.52679	0.12679	7.88683	0.06679	14.9714
12	2.01218	0.49697	0.11928	8.38380	0.05928	16.8697
13	2.13291	0.46884	0.11296	8.85263	0.05296	18.8818
14	2.26089	0.44230	0.10759	9.29493	0.04759	21.0147
15	2.39654	0.41727	0.10296	9.71220	0.04296	23.2756
16	2.54033	0.39365	0.09895	10.10585	0.03895	25.6721
17	2.69275	0.37137	0.09545	10.47721	0.03545	28.2124
18	2.85431	0.35035	0.09236	10.82755	0.03236	30.9052
19	3.02557	0.33052	0.08962	11.15807	0.02962	33.7594
20	3.20710	0.31181	0.08718	11.46987	0.02718	36.7850
21	3.39953	0.29416	0.08500	11.76403	0.02500	39.9921
22	3.60350	0.27751	0.08305	12.04153	0.02305	43.3916
23	3.81971	0.26180	0.08128	12.30333	0.02128	46.9950
24	4.04889	0.24698	0.07968	12.55031	0.01968	50.8147
25	4.29182	0.23300	0.07823	12.78331	0.01823	54.8636
26	4.54932	0.21981	0.07690	13.00312	0.01690	59.1553
27	4.82228	0.20737	0.07570	13.21049	0.01570	63.7046
28	5.11161	0.19563	0.07459	13.40613	0.01459	68.5269
29	5.41831	0.18456	0.07358	13.59068	0.01358	73.6384
30	5.74340	0.17411	0.07265	13.76479	0.01265	79.0567
31	6.08801	0.16426	0.07179	13.92905	0.01179	84.8000
32	6.45328	0.15496	0.07100	14.08401	0.01100	90.8880
33	6.84048	0.14619	0.07027	14.23020	0.01027	97.3412
34	7.25090	0.13791	0.06960	14.36810	0.00960	104.1816
35	7.68595	0.13011	0.06897	14.49821	0.00897	111.4325
36	8.14710	0.12274	0.06839	14.62096	0.00840	119.1183
37	8.63593	0.11580	0.06786	14.73675	0.00786	127.2654
38	9.15408	0.10924	0.06736	14.84599	0.00736	135.9013
39	9.70332	0.10306	0.06689	14.94905	0.00689	145.0553
40	10.28551	0.09722	0.06646	15.04628	0.00646	154.7585

7.00% COMPOUND INTEREST FACTORS

ERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.07000	0.93458	1.07000	0.93458	1.00000	1.0000
2	1.14490	0.87344	0.55310	1.80800	0.48310	2.0699
3	1.22504	0.81630	0.38105	2.62430	0.31105	3.2148
4	1.31079	0.76290	0.29523	3.38720	0.22523	4.4399
5	1.40255	0.71299	0.24389	4.10018	0.17389	5.7507
6	1.50073	0.66634	0.20980	4.76652	0.13980	7.1532
7	1.60578	0.62275	0.18555	5.38927	0.11555	8.6539
8	1.71818	0.58201	0.16747	5.97128	0.09747	10.2597
9	1.83845	0.54394	0.15349	6.51522	0.08349	11.9779
10	1.96714	0.50835	0.14238	7.02356	0.07238	13.8163
11	2.10485	0.47509	0.13336	7.49866	0.06336	15.7835
12	2.25218	0.44401	0.12590	7.94267	0.05590	17.8883
13	2.40984	0.41497	0.11965	8.35763	0.04965	20.1405
14	2.57852	0.38782	0.11435	8.74545	0.04435	22.5503
15	2.75902	0.36245	0.10979	9.10789	0.03979	25.1288
16	2.95215	0.33874	0.10586	9.44663	0.03586	27.8878
17	3.15880	0.31658	0.10243	9.76320	0.03243	30.8399
18	3.37991	0.29587	0.09941	10.05907	0.02941	33.9987
19	3.61651	0.27651	0.09675	10.33558	0.02675	37.3786
20	3.86966	0.25842	0.09439	10.59400	0.02439	40.9951
21	4.14054	0.24151	0.09229	10.83551	0.02229	44.8648
22	4.43037	0.22571	0.09041	11.06123	0.02041	49.0053
23	4.74050	0.21095	0.08871	11.27217	0.01871	53.4357
24	5.07233	0.19715	0.08719	11.46932	0.01719	58.1761
25	5.42739	0.18425	0.08581	11.65357	0.01581	63.2484
26	5.80731	0.17220	0.08456	11.82577	0.01456	68.6758
27	6.21382	0.16093	0.08343	11.98670	0.01343	74.4831
28	6.64878	0.15040	0.08239	12.13710	0.01239	80.6969
29	7.11420	0.14056	0.08145	12.27766	0.01145	87.3457
30	7.61219	0.13137	0.08059	12.40903	0.01059	94.4598
31	8.14504	0.12277	0.07980	12.53180	0.00980	102.0720
32	8.71519	0.11474	0.07907	12.64655	0.00907	110.2170
33	9.32525	0.10724	0.07841	12.75378	0.00841	118.9321
34	9.97802	0.10022	0.07780	12.85401	0.00780	128.2574
35	10.67647	0.09366	0.07723	12.94766	0.00723	138.2353
36	11.42382	0.08754	0.07672	13.03520	0.00672	148.9118
37	12.22349	0.08181	0.07624	13.11701	0.00624	160.3355
38	13.07913	0.07646	0.07580	13.19347	0.00580	172.5590
39	13.99466	0.07146	0.07539	13.26493	0.00539	185.6380
40	14.97429	0.06678	0.07501	13.33170	0.00501	199.6327

8.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.08000	0.92593	1.08000	0.92593	1.00000	1.0000
2	1.16640	0.85734	0.56077	1.78326	0.48077	2.0799
3	1.25971	0.79383	0.38803	2.57709	0.30803	3.2463
4	1.36049	0.73503	0.30192	3.31212	0.22192	4.5061
5	1.46933	0.68058	0.25046	3.99271	0.17046	5.8665
6	1.58687	0.63017	0.21632	4.62288	0.13632	7.3359
7	1.71382	0.58349	0.19207	5.20637	0.11207	8.9228
8	1.85093	0.54027	0.17401	5.74664	0.09401	10.6366
9	1.99900	0.50025	0.16008	6.24688	0.08008	12.4875
10	2.15892	0.46319	0.14903	6.71008	0.06903	14.4865
11	2.33164	0.42888	0.14008	7.13896	0.06008	16.6454
12	2.51817	0.39711	0.13270	7.53608	0.05270	18.9771
13	2.71962	0.36770	0.12652	7.90377	0.04652	21.4952
14	2.93719	0.34046	0.12130	8.24424	0.04130	24.2148
15	3.17216	0.31524	0.11683	8.55948	0.03683	27.1520
16	3.42594	0.29189	0.11298	8.85137	0.03298	30.3242
17	3.70001	0.27027	0.10963	9.12164	0.02963	33.7501
18	3.99601	0.25025	0.10670	9.37189	0.02670	37.4501
19	4.31569	0.23171	0.10413	9.60360	0.02413	41.4461
20	4.66095	0.21455	0.10185	9.81815	0.02185	45.7618
21	5.03383	0.19866	0.09983	10.01680	0.01983	50.4228
22	5.43653	0.18394	0.09803	10.20074	0.01803	55.4566
23	5.87145	0.17032	0.09642	10.37106	0.01642	60.8931
24	6.34117	0.15770	0.09498	10.52876	0.01498	66.7646
25	6.84846	0.14602	0.09368	10.67478	0.01368	73.1058
26	7.39634	0.13520	0.09251	10.80998	0.01251	79.9542
27	7.98805	0.12519	0.09145	10.93517	0.01145	87.3505
28	8.62709	0.11591	0.09049	11.05108	0.01049	95.3386
29	9.31726	0.10733	0.08962	11.15841	0.00962	103.9657
30	10.06266	0.09938	0.08883	11.25779	0.00883	113.2829
31	10.86765	0.09202	0.08811	11.34981	0.00811	123.3456
32	11.73706	0.08520	0.08745	11.43500	0.00745	134.2132
33	12.67602	0.07889	0.08685	11.51389	0.00685	145.9503
34	13.69010	0.07305	0.08630	11.58695	0.00630	158.6263
35	14.78531	0.06763	0.08580	11.65458	0.00580	172.3164
36	15.96813	0.06262	0.08534	11.71720	0.00534	187.1017
37	17.24557	0.05799	0.08492	11.77519	0.00492	203.0697
38	18.62521	0.05369	0.08454	11.82888	0.00454	220.3152
39	20.11523	0.04971	0.08419	11.87859	0.00419	238.9406
40	21.72446	0.04603	0.08386	11.92462	0.00386	259.0556

9.00% COMPOUND INTEREST FACTORS

	SINGLE PAYMENT		UNIFORM SERIES			
PERIODS	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.09000	0.91743	1.09001	0.91742	1.00001	0.9999
2	1.18810	0.84168	0.56847	1.75910	0.47847	2.0899
3	1.29503	0.77219	0.39506	2.53128	0.30506	3.2780
4	1.41158	0.70843	0.30867	3.23970	0.21867	4.5730
5	1.53862	0.64993	0.25709	3.88963	0.16709	5.9846
6	1.67709	0.59627	0.22292	4.48589	0.13292	7.5232
7	1.82803	0.547[illegible]4	0.19869	5.03292	0.10869	9.2003
8	1.99255	0.50187	0.18068	5.53479	0.09068	11.0283
9	2.17188	0.46043	0.16680	5.99522	0.07680	13.0208
10	2.36735	0.42241	0.15582	6.41763	0.06582	15.1927
11	2.58041	0.38754	0.14695	6.80516	0.05695	17.5600
12	2.81264	0.35554	0.13965	7.16070	0.04965	20.1404
13	3.06577	0.32618	0.13357	7.48687	0.04357	22.9530
14	3.34169	0.29925	0.12843	7.78612	0.03843	26.0188
15	3.64244	0.27454	0.12406	8.06066	0.03406	29.3604
16	3.97026	0.25187	0.12030	8.31253	0.03030	33.0028
17	4.32758	0.23108	0.11705	8.54361	0.02705	36.9731
18	4.71706	0.21200	0.11421	8.75560	0.02421	41.3006
19	5.14159	0.19449	0.11173	8.95009	0.02173	46.0176
20	5.60433	0.17843	0.10955	9.12852	0.01955	51.1592
21	6.10871	0.16370	0.10762	9.29222	0.01762	56.7634
22	6.65849	0.15018	0.10591	9.44240	0.01591	62.8721
23	7.25775	0.13778	0.10438	9.58019	0.01438	69.5305
24	7.91094	0.12641	0.10302	9.70659	0.01302	76.7882
25	8.62292	0.11597	0.10181	9.82256	0.01181	84.6991
26	9.39898	0.10639	0.10072	9.92896	0.01072	93.3220
27	10.24488	0.09761	0.09974	10.02656	0.00974	102.7209
28	11.16691	0.08955	0.09885	10.11612	0.00885	112.9657
29	12.17192	0.08216	0.09806	10.19827	0.00806	124.1325
30	13.26739	0.07537	0.09734	10.27364	0.00734	136.3043
31	14.46144	0.06915	0.09669	10.34279	0.00669	149.5716
32	15.76296	0.06344	0.09610	10.40624	0.00610	164.0329
33	17.18161	0.05820	0.09556	10.46444	0.00556	179.7957
34	18.72794	0.05340	0.09508	10.51783	0.00508	196.9772
35	20.41344	0.04899	0.09464	10.56681	0.00464	215.7050
36	22.25063	0.04494	0.09424	10.61176	0.00424	236.1181
37	24.25317	0.04123	0.09387	10.65299	0.00387	258.3686
38	26.43593	0.03783	0.09354	10.69082	0.00354	282.6213
39	28.81516	0.03470	0.09324	10.72552	0.00324	309.0573
40	31.40849	0.03184	0.09296	10.75736	0.00296	337.8720

10.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.10000	0.90909	1.10001	0.90909	1.00001	0.9999
2	1.21000	0.82645	0.57619	1.73552	0.47619	2.0999
3	1.33100	0.75132	0.40212	2.48684	0.30212	3.3099
4	1.46410	0.68302	0.31547	3.16985	0.21547	4.6409
5	1.61051	0.62092	0.26380	3.79077	0.16380	6.1050
6	1.77155	0.56448	0.22961	4.35524	0.12961	7.7155
7	1.94871	0.51316	0.20541	4.86840	0.10541	9.4870
8	2.14358	0.46651	0.18744	5.33490	0.08744	11.4358
9	2.35794	0.42410	0.17364	5.75900	0.07364	13.5793
10	2.59373	0.38555	0.16275	6.14455	0.06275	15.9372
11	2.85310	0.35050	0.15396	6.49504	0.05396	18.5309
12	3.13841	0.31863	0.14676	6.81367	0.04676	21.3840
13	3.45225	0.28967	0.14078	7.10334	0.04078	24.5224
14	3.79747	0.26333	0.13575	7.36667	0.03575	27.9746
15	4.17721	0.23939	0.13147	7.60606	0.03147	31.7721
16	4.59493	0.21763	0.12782	7.82369	0.02782	35.9493
17	5.05443	0.19785	0.12466	8.02153	0.02466	40.5442
18	5.55986	0.17986	0.12193	8.20139	0.02193	45.5986
19	6.11585	0.16351	0.11955	8.36491	0.01955	51.1584
20	6.72743	0.14865	0.11746	8.51355	0.01746	57.2742
21	7.40017	0.13513	0.11562	8.64868	0.01562	64.0016
22	8.14018	0.12285	0.11401	8.77152	0.01401	71.4017
23	8.95420	0.11168	0.11257	8.88321	0.01257	79.5419
24	9.84961	0.10153	0.11130	8.98473	0.01130	88.4960
25	10.83456	0.09230	0.11017	9.07703	0.01017	98.3456
26	11.91801	0.08391	0.10916	9.16094	0.00916	109.1801
27	13.10981	0.07628	0.10826	9.23722	0.00826	121.0980
28	14.42078	0.06934	0.10745	9.30655	0.00745	134.2078
29	15.86285	0.06304	0.10673	9.36959	0.00673	148.6285
30	17.44913	0.05731	0.10608	9.42691	0.00608	164.4912
31	19.19403	0.05210	0.10550	9.47901	0.00550	181.9402
32	21.11342	0.04736	0.10497	9.52637	0.00497	201.1341
33	23.22475	0.04306	0.10450	9.56943	0.00450	222.2475
34	25.54721	0.03914	0.10407	9.60857	0.00407	245.4722
35	28.10191	0.03558	0.10369	9.64416	0.00369	271.0190
36	30.91209	0.03235	0.10334	9.67650	0.00334	299.1208
37	34.00328	0.02941	0.10303	9.70591	0.00303	330.0327
38	37.40359	0.02674	0.10275	9.73265	0.00275	364.0356
39	41.14394	0.02430	0.10249	9.75695	0.00249	401.4392
40	45.25830	0.02210	0.10226	9.77905	0.00226	442.5827

11.00% COMPOUND INTEREST FACTORS

	SINGLE PAYMENT		UNIFORM SERIES			
PERIODS	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.11000	0.90090	1.11000	0.90090	1.00000	1.0000
2	1.23210	0.81162	0.58354	1.71251	0.47394	2.1099
3	1.36763	0.73119	0.40921	2.44370	0.29921	3.3420
4	1.51807	0.65873	0.32233	3.10244	0.21233	4.7097
5	1.68505	0.59345	0.27057	3.69589	0.16057	6.2277
6	1.87041	0.53464	0.23638	4.23053	0.12638	7.9128
7	2.07615	0.48166	0.21222	4.71218	0.10222	9.7832
8	2.30453	0.43393	0.19432	5.14611	0.08432	11.8593
9	2.55803	0.39093	0.18060	5.53704	0.07060	14.1639
10	2.83941	0.35219	0.16980	5.88922	0.05980	16.7219
11	3.15175	0.31728	0.16112	6.20651	0.05112	19.5613
12	3.49844	0.28584	0.15403	6.49235	0.04403	22.7130
13	3.88326	0.25752	0.14815	6.74986	0.03815	26.2114
14	4.31042	0.23200	0.14323	6.98186	0.03323	30.0947
15	4.78457	0.20901	0.13907	7.19086	0.02907	34.4051
16	5.31087	0.18829	0.13552	7.37915	0.02552	39.1897
17	5.89506	0.16963	0.13247	7.54879	0.02247	44.5005
18	6.54352	0.15282	0.12984	7.70161	0.01984	50.3956
19	7.26330	0.13768	0.12756	7.83929	0.01756	56.9390
20	8.06228	0.12403	0.12558	7.96332	0.01558	64.2023
21	8.94911	0.11174	0.12384	8.07506	0.01384	72.2646
22	9.93351	0.10067	0.12231	8.17574	0.01231	81.2136
23	11.02619	0.09069	0.12097	8.26643	0.01097	91.1471
24	12.23903	0.08171	0.11979	8.34813	0.00979	102.1733
25	13.58536	0.07361	0.11874	8.42174	0.00874	114.4123
26	15.07974	0.06631	0.11781	8.48806	0.00781	127.9976
27	16.73851	0.05974	0.11699	8.54780	0.00699	143.0773
28	18.57973	0.05382	0.11626	8.60162	0.00626	159.8157
29	20.62350	0.04849	0.11561	8.65011	0.00561	178.3954
30	22.89207	0.04368	0.11502	8.69379	0.00502	199.0188
31	25.41020	0.03935	0.11451	8.73314	0.00451	221.9109
32	28.20531	0.03545	0.11404	8.76860	0.00404	247.3211
33	31.30789	0.03194	0.11363	8.80054	0.00363	275.5261
34	34.75174	0.02878	0.11326	8.82931	0.00326	306.8337
35	38.57441	0.02592	0.11293	8.85524	0.00293	341.5856
36	42.81760	0.02335	0.11263	8.87860	0.00263	380.1599
37	47.52753	0.02104	0.11236	8.89963	0.00236	422.9772
38	52.75554	0.01896	0.11213	8.91659	0.00213	470.5046
39	58.55862	0.01708	0.11191	8.93567	0.00191	523.2600
40	65.00004	0.01538	0.11172	8.95105	0.00172	581.8186

12.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.12000	0.89286	1.12000	0.89286	1.00000	1.0000
2	1.25440	0.79719	0.59170	1.69005	0.47170	2.1199
3	1.40493	0.71178	0.41635	2.40183	0.29635	3.3743
4	1.57352	0.63552	0.32923	3.03734	0.20924	4.7793
5	1.76234	0.56743	0.27741	3.60477	0.15741	6.3528
6	1.97382	0.50663	0.24323	4.11140	0.12323	8.1151
7	2.21068	0.45235	0.21912	4.56375	0.09912	10.0890
8	2.47596	0.40388	0.20130	4.96764	0.08130	12.2996
9	2.77308	0.36061	0.18768	5.32825	0.06768	14.7756
10	3.10584	0.32197	0.17698	5.65022	0.05698	17.5486
11	3.47855	0.28748	0.16842	5.93770	0.04842	20.6545
12	3.89597	0.25668	0.16144	6.19437	0.04144	24.1330
13	4.36349	0.22917	0.15568	6.42355	0.03568	28.0290
14	4.88710	0.20462	0.15087	6.62817	0.03087	32.3925
15	5.47356	0.18270	0.14682	6.81086	0.02682	37.2796
16	6.13038	0.16312	0.14339	6.97398	0.02339	42.7531
17	6.86603	0.14564	0.14046	7.11963	0.02046	48.8835
18	7.68995	0.13004	0.13794	7.24967	0.01794	55.7495
19	8.61274	0.11611	0.13576	7.36578	0.01576	63.4395
20	9.64627	0.10367	0.13388	7.46944	0.01388	72.0522
21	10.80382	0.09256	0.13224	7.469[illegible]4	0.01224	81.6985
22	12.10028	0.08264	0.13081	7.64465	0.01081	92.5023
23	13.55231	0.07379	0.12956	7.71844	0.00956	104.6026
24	15.17859	0.06588	0.12846	7.78432	0.00846	118.1549
25	17.00002	0.05882	0.12750	7.84314	0.00750	133.3334
26	19.04001	0.05252	0.12665	7.89566	0.00665	150.3334
27	21.32481	0.04689	0.12590	7.94255	0.00590	169.3734
28	23.88379	0.04187	0.12524	7.98442	0.00524	190.6982
29	26.74985	0.03738	0.12466	8.02181	0.00466	214.5821
30	29.95982	0.03338	0.12414	8.05518	0.00414	241.3319
31	33.55499	0.02980	0.12369	8.08499	0.00369	271.2915
32	37.58159	0.02661	0.12328	8.11160	0.00328	304.8464
33	42.09138	0.02376	0.12292	8.13535	0.00292	342.4279
34	47.14235	0.02121	0.12260	8.15657	0.00260	384.5195
35	52.79942	0.01894	0.12232	8.17550	0.00232	431.6616
36	59.13535	0.01691	0.12206	8.19242	0.00206	484.4611
37	66.23158	0.01510	0.12184	8.20751	0.00184	543.5964
38	74.17937	0.01348	0.12164	8.22099	0.00164	609.8278
39	83.08089	0.01204	0.12146	8.23303	0.00146	684.0073
40	93.05056	0.01075	0.12130	8.24378	0.00130	767.0881

13.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.13000	0.88496	1.13001	0.88495	1.00001	0.9999
2	1.27690	0.78315	0.59949	1.66809	0.46949	2.1299
3	1.44289	0.69305	0.42352	2.36114	0.29352	3.4068
4	1.63047	0.61332	0.33620	2.97446	0.20620	4.8497
5	1.84243	0.54276	0.28432	3.51722	0.15432	6.4802
6	2.08194	0.48032	0.25015	3.99753	0.12015	8.3226
7	2.35259	0.42506	0.22611	4.42259	0.09611	10.4045
8	2.65843	0.37616	0.20839	4.79875	0.07839	12.7571
9	3.00402	0.33289	0.19487	5.13164	0.06487	15.4155
10	3.39454	0.29459	0.18429	5.42623	0.05429	18.4195
11	3.83583	0.26070	0.17584	5.68692	0.04584	21.8140
12	4.33448	0.23071	0.16899	5.91763	0.03899	25.6498
13	4.89796	0.20417	0.16335	6.12180	0.03335	29.9843
14	5.53469	0.18068	0.15867	6.30247	0.02867	34.8822
15	6.25420	0.15989	0.15474	6.46237	0.02474	40.4169
16	7.06724	0.14150	0.15143	6.60386	0.02143	46.6710
17	7.98598	0.12522	0.14861	6.72908	0.01861	53.7382
18	9.02415	0.11081	0.14620	6.83990	0.01620	61.7242
19	10.19728	0.09807	0.14413	6.93796	0.01413	70.7482
20	11.52292	0.08678	0.14235	7.02475	0.01235	80.9455
21	13.02089	0.07680	0.14081	7.10154	0.01081	92.4683
22	14.71359	0.06796	0.13948	7.16951	0.00948	105.4891
23	16.62634	0.06015	0.13832	7.22965	0.00832	120.2026
24	18.78775	0.05323	0.13731	7.28288	0.00731	136.8288
25	21.23013	0.04710	0.13643	7.32998	0.00643	155.6164
26	23.99004	0.04168	0.13565	7.37166	0.00565	176.8464
27	27.10873	0.03689	0.13498	7.40855	0.00498	200.8364
28	30.63284	0.03264	0.13439	7.44120	0.00439	227.9450
29	34.61508	0.02889	0.13387	7.47009	0.00387	258.5773
30	39.11502	0.02557	0.13341	7.49565	0.00341	293.1923
31	44.19994	0.02262	0.13301	7.51828	0.00301	332.3071
32	49.94589	0.02002	0.13266	7.53830	0.00266	376.5068
33	56.43883	0.01772	0.13234	7.55601	0.00234	426.4523
34	63.77582	0.01568	0.13207	7.57169	0.00207	482.8908
35	72.06662	0.01388	0.13183	7.58557	0.00183	546.6662
36	81.43523	0.01228	0.13162	7.59785	0.00162	618.7324
37	92.02174	0.01087	0.13143	7.60872	0.00143	700.1672
38	103.98440	0.00962	0.13126	7.61833	0.00126	792.1884
39	117.50230	0.00851	0.13112	7.62685	0.00112	896.1721
40	132.77760	0.00753	0.13099	7.63438	0.00099	1013.6730

14.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.14000	0.87719	1.14000	0.87719	1.00000	1.0000
2	1.29960	0.76947	0.60729	1.64665	0.46729	2.1399
3	1.48154	0.67497	0.43073	2.32162	0.29073	3.4395
4	1.68896	0.59208	0.34321	2.91370	0.20321	4.9211
5	1.92541	0.51937	0.29128	3.43307	0.15128	6.6100
6	2.19497	0.45559	0.25716	3.88866	0.11716	8.5354
7	2.50226	0.39964	0.23319	4.28829	0.09319	10.7304
8	2.85257	0.35056	0.21557	4.63885	0.07557	13.2326
9	3.25193	0.30751	0.20217	4.94636	0.06217	16.0852
10	3.70720	0.26975	0.19171	5.21611	0.05171	19.3371
11	4.22621	0.23662	0.18339	5.45272	0.04339	23.0443
12	4.81787	0.20756	0.17667	5.66028	0.03667	27.2705
13	5.49237	0.18207	0.17116	5.84235	0.03116	32.0883
14	6.26130	0.15971	0.16661	6.00206	0.02661	37.5807
15	7.13788	0.14010	0.16281	6.14216	0.02281	43.8420
16	8.13718	0.12289	0.15962	6.26505	0.01962	50.9798
17	9.27638	0.10780	0.15692	6.37285	0.01692	59.1170
18	10.57507	0.09456	0.15462	6.46742	0.01462	68.3933
19	12.05557	0.08295	0.15266	6.55037	0.01266	78.9683
20	13.74334	0.07276	0.15099	6.62313	0.01099	91.0238
21	15.66740	0.06383	0.14954	6.68695	0.00954	104.7671
22	17.86082	0.05599	0.14830	6.74294	0.00830	120.4344
23	20.36133	0.04911	0.14723	6.79206	0.00723	138.2952
24	23.21190	0.04308	0.14630	6.83514	0.00630	158.6564
25	26.46155	0.03779	0.14550	6.87293	0.00550	181.8683
26	30.16615	0.03315	0.14480	6.90608	0.00480	208.3298
27	34.38940	0.02908	0.14419	6.93515	0.00419	238.4958
28	39.20390	0.02551	0.14366	6.96066	0.00366	272.8850
29	44.69241	0.02238	0.14320	6.98304	0.00320	312.0880
30	50.94933	0.01963	0.14280	7.00266	0.00280	356.7807
31	58.08221	0.01722	0.14245	7.01988	0.00245	407.7299
32	66.21368	0.01510	0.14215	7.03498	0.00215	465.8120
33	75.48357	0.01325	0.14188	7.04823	0.00188	532.0253
34	86.05121	0.01162	0.14165	7.05985	0.00165	607.5085
35	98.09833	0.01019	0.14144	7.07005	0.00144	693.5595
36	111.83200	0.00894	0.14126	7.07899	0.00126	791.6574
37	127.48840	0.00784	0.14111	7.08683	0.00111	903.4890
38	145.33670	0.00688	0.14097	7.09371	0.00097	1030.9770
39	165.68380	0.00604	0.14085	7.09975	0.00085	1176.3130
40	188.87940	0.00529	0.14075	7.10504	0.00075	1341.9960

15.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.15000	0.86957	1.15000	0.86956	1.00000	1.0000
2	1.32250	0.75614	0.61512	1.62570	0.46512	2.1499
3	1.52087	0.65752	0.43798	2.28322	0.28798	3.4724
4	1.74900	0.57175	0.35027	2.85497	0.20027	4.9933
5	2.01135	0.49718	0.29832	3.35215	0.14832	6.7423
6	2.31306	0.43233	0.26424	3.78448	0.11424	8.7537
7	2.66001	0.37594	0.24036	4.16041	0.09036	11.0667
8	3.05901	0.32690	0.22285	4.48732	0.07285	13.7267
9	3.51787	0.28426	0.20957	4.77158	0.05957	16.7857
10	4.04554	0.24719	0.19925	5.01876	0.04925	20.3036
11	4.65237	0.21494	0.19107	5.23371	0.04107	24.3491
12	5.35023	0.18691	0.18448	5.42062	0.03448	29.0015
13	6.15276	0.16253	0.17911	5.58314	0.02911	34.3517
14	7.07567	0.14133	0.17469	5.72448	0.02469	40.5044
15	8.13702	0.12290	0.17102	5.84737	0.02102	47.5801
16	9.35757	0.10687	0.16795	5.95423	0.01795	55.7171
17	10.76120	0.09293	0.16537	6.04716	0.01537	65.0747
18	12.37538	0.08081	0.16319	6.12797	0.01319	75.8358
19	14.23168	0.07027	0.16134	6.19823	0.01134	88.2112
20	16.36642	0.06110	0.15976	6.25933	0.00976	102.4428
21	18.82138	0.05313	0.15842	6.31246	0.00842	118.8092
22	21.64458	0.04620	0.15727	6.35866	0.00727	137.6305
23	24.89127	0.04017	0.15628	6.39884	0.00628	159.2752
24	28.62494	0.03493	0.15543	6.43377	0.00543	184.1662
25	32.91867	0.03038	0.15470	6.46415	0.00470	212.7911
26	37.85646	0.02642	0.15407	6.49057	0.00407	245.7099
27	43.53491	0.02297	0.15353	6.51354	0.00353	283.5659
28	50.06514	0.01997	0.15306	6.53351	0.00306	327.1008
29	57.57489	0.01737	0.15265	6.55088	0.00265	377.1657
30	66.21111	0.01510	0.15230	6.56598	0.00230	434.7407
31	76.14275	0.01313	0.15200	6.57911	0.00200	500.9516
32	87.56413	0.01142	0.15173	6.59054	0.00173	577.0942
33	100.69870	0.00993	0.15150	6.60047	0.00150	664.6582
34	115.80340	0.00864	0.15131	6.60910	0.00131	765.3566
35	133.17390	0.00751	0.15113	6.61661	0.00113	881.1599
36	153.15000	0.00653	0.15099	6.62314	0.00099	1014.3330
37	176.12240	0.00568	0.15086	6.62882	0.00086	1167.4830
38	202.54070	0.00494	0.15074	6.63375	0.00074	1343.6050
39	232.92170	0.00429	0.15065	6.63805	0.00065	1546.1450
40	267.85980	0.00373	0.15056	6.64178	0.00056	1779.0660

20.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT		UNIFORM SERIES			
	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.20000	0.83333	1.20000	0.83333	1.00000	1.0000
2	1.44000	0.69445	0.65455	1.52777	0.45455	2.1999
3	1.72800	0.57870	0.47473	2.10648	0.27473	3.6399
4	2.07360	0.48225	0.38629	2.58873	0.18629	5.3679
5	2.48832	0.40188	0.33438	2.99061	0.13438	7.4415
6	2.98598	0.33490	0.30071	3.32551	0.10071	9.9299
7	3.58318	0.27908	0.27742	3.60459	0.07742	12.9158
8	4.29981	0.23257	0.26061	3.83716	0.06061	16.4990
9	5.15977	0.19381	0.24808	4.03097	0.04808	20.7988
10	6.19173	0.16151	0.23852	4.19247	0.03852	25.9586
11	7.43007	0.13459	0.23110	4.32706	0.03110	32.1503
12	8.91608	0.11216	0.22526	4.43922	0.02527	39.5804
13	10.69930	0.09346	0.22062	4.53268	0.02062	48.4964
14	12.83916	0.07789	0.21689	4.61057	0.01689	59.1957
15	15.40698	0.06491	0.21388	4.67547	0.01388	72.0349
16	18.48837	0.05409	0.21144	4.72956	0.01144	87.4418
17	22.18605	0.04507	0.20944	4.77463	0.00944	105.9302
18	26.62325	0.03756	0.20781	4.81220	0.00781	128.1162
19	31.94789	0.03130	0.20646	4.84350	0.00646	154.7395
20	38.33746	0.02608	0.20536	4.86958	0.00536	186.6874
21	46.00496	0.02174	0.20444	4.89132	0.00444	225.0249
22	55.20595	0.01811	0.20369	4.90943	0.00369	271.0295
23	66.24712	0.01509	0.20307	4.92453	0.00307	326.2355
24	79.49654	0.01258	0.20255	4.93710	0.00255	392.4826
25	95.39583	0.01048	0.20212	4.94759	0.00212	471.9790
26	114.47490	0.00874	0.20176	4.95632	0.00176	567.3747
27	137.36990	0.00728	0.20147	4.96360	0.00147	681.8496
28	164.84390	0.00607	0.20122	4.96967	0.00122	819.2194
29	197.81260	0.00506	0.20102	4.97472	0.00102	984.0634
30	237.37510	0.00421	0.20085	4.97894	0.00085	1181.8750
31	284.85000	0.00351	0.20070	4.98245	0.00070	1419.2500
32	341.82000	0.00293	0.20059	4.98537	0.00059	1704.1000
33	410.18400	0.00244	0.20049	4.98781	0.00049	2045.9200
34	492.22070	0.00203	0.20041	4.98984	0.00041	2456.1040
35	590.66470	0.00169	0.20034	4.99154	0.00034	2948.3250
36	708.79760	0.00141	0.20028	4.99295	0.00028	3538.9890
37	850.55710	0.00118	0.20024	4.99412	0.00024	4247.7850
38	1020.66800	0.00098	0.20020	4.99510	0.00020	5098.3390
39	1224.80200	0.00082	0.20016	4.99592	0.00016	6119.0070
40	1469.76200	0.00068	0.20014	4.99660	0.00014	7343.8080

25.00% COMPOUND INTEREST FACTORS

	SINGLE PAYMENT		UNIFORM SERIES			
RIODS	COMPOUND AMOUNT FACTOR SCA	PRESENT WORTH FACTOR SPW	CAPITOL RECOVERY FACTOR UCR	PRESENT WORTH FACTOR UPW	SINKING FUND FACTOR USF	COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.25000	0.80000	1.25000	0.80000	1.00000	1.0000
2	1.56250	0.64000	0.69444	1.44000	0.44444	2.2500
3	1.95313	0.51200	0.51230	1.95200	0.26230	3.8125
4	2.44141	0.40960	0.42344	2.36160	0.17344	5.7656
5	3.05176	0.32768	0.37185	2.68928	0.12185	8.2070
6	3.81470	0.26214	0.33882	2.95142	0.08882	11.2588
7	4.76837	0.20972	0.31634	3.16114	0.06634	15.0734
8	5.96046	0.16777	0.30040	3.32891	0.05040	19.8418
9	7.45058	0.13422	0.28876	3.46313	0.03876	25.8023
10	9.31323	0.10737	0.28007	3.57050	0.03007	33.2529
11	11.64153	0.08590	0.27349	3.65640	0.02349	42.5661
12	14.55192	0.06872	0.26845	3.72512	0.01845	54.2076
13	18.18988	0.05498	0.26454	3.78010	0.01454	68.7595
14	22.73737	0.04398	0.26150	3.82408	0.01150	86.9494
15	28.42171	0.03518	0.25912	3.85926	0.00912	109.6868
16	35.52713	0.02815	0.25724	3.88741	0.00724	138.1085
17	44.40892	0.02252	0.25576	3.90993	0.00576	173.6357
18	55.51114	0.01801	0.25459	3.92794	0.00459	218.0446
19	69.38893	0.01441	0.25366	3.94235	0.00366	273.5556
20	86.73616	0.01153	0.25292	3.95388	0.00292	342.9445
21	108.42020	0.00922	0.25233	3.96311	0.00233	429.6806
22	135.52520	0.00738	0.25186	3.97049	0.00186	538.1010
23	169.40650	0.00590	0.25148	3.97639	0.00148	673.6262
24	211.75820	0.00472	0.25119	3.98111	0.00119	843.0329
25	264.69770	0.00378	0.25095	3.98489	0.00095	1054.7910
26	330.87200	0.00302	0.25076	3.98791	0.00076	1319.4880
27	413.59000	0.00242	0.25061	3.99033	0.00061	1650.3600
28	516.98770	0.00193	0.25048	3.99226	0.00048	2063.9510
29	646.23460	0.00155	0.25039	3.99381	0.00039	2580.9390
30	807.79340	0.00124	0.25031	3.99505	0.00031	3227.1750
31	1009.74100	0.00099	0.25025	3.99604	0.00025	4034.9690
32	1262.17700	0.00079	0.25020	3.99683	0.00020	5044.7070
33	1577.72100	0.00063	0.25016	3.99746	0.00016	6306.8860
34	1972.15200	0.00051	0.25013	3.99797	0.00013	7884.6050
35	2465.19000	0.00041	0.25010	3.99838	0.00010	9856.7570
36	3081.48700	0.00032	0.25008	3.99870	0.00008	12321.9400
37	3851.85900	0.00026	0.25006	3.99896	0.00006	15403.4300
38	4814.82400	0.00021	0.25005	3.99917	0.00005	19255.3000
39	6018.52700	0.00017	0.25004	3.99934	0.00004	24070.1100
40	7523.16000	0.00013	0.25003	3.99947	0.00003	30088.6400

30.00% COMPOUND INTEREST FACTORS

PERIODS	SINGLE PAYMENT: COMPOUND AMOUNT FACTOR SCA	SINGLE PAYMENT: PRESENT WORTH FACTOR SPW	UNIFORM SERIES: CAPITOL RECOVERY FACTOR UCR	UNIFORM SERIES: PRESENT WORTH FACTOR UPW	UNIFORM SERIES: SINKING FUND FACTOR USF	UNIFORM SERIES: COMPOUND AMOUNT FACTOR UCA
	1	2	3	4	5	6
1	1.30000	0.76923	1.30000	0.76923	1.00000	1.0000
2	1.69000	0.59172	0.73478	1.36094	0.43478	2.2999
3	2.19700	0.45517	0.55063	1.81611	0.25063	3.9899
4	2.85609	0.35013	0.46163	2.16624	0.16163	6.1869
5	3.71292	0.26933	0.41058	2.43557	0.11058	9.0430
6	4.82679	0.20718	0.37839	2.64274	0.07839	12.7559
7	6.27483	0.15937	0.35687	2.80211	0.05687	17.5827
8	8.15727	0.12259	0.34192	2.92470	0.04192	23.8575
9	10.60444	0.09430	0.33124	3.01900	0.03124	32.0148
10	13.78577	0.07254	0.32346	3.09154	0.02346	42.6192
11	17.92148	0.05580	0.31773	3.14734	0.01773	56.4049
12	23.29791	0.04292	0.31345	3.19026	0.01345	74.3263
13	30.28728	0.03302	0.31024	3.22328	0.01024	97.6242
14	39.37343	0.02540	0.30782	3.24867	0.00782	127.9114
15	51.18544	0.01954	0.30598	3.26821	0.00598	167.2848
16	66.54103	0.01503	0.30458	3.28324	0.00458	218.4702
17	86.50330	0.01156	0.30351	3.29480	0.00351	285.0197
18	112.45420	0.00889	0.30269	3.30369	0.00269	371.5139
19	146.19030	0.00684	0.30207	3.31053	0.00207	483.9677
20	190.04730	0.00526	0.30159	3.31579	0.00159	630.1579
21	247.06140	0.00405	0.30122	3.31984	0.00122	820.2048
22	321.17960	0.00311	0.30094	3.32296	0.00094	1067.2650
23	417.53320	0.00240	0.30072	3.32535	0.00072	1388.4440
24	542.79290	0.00184	0.30055	3.32719	0.00055	1805.9760
25	705.63060	0.00142	0.30043	3.32861	0.00043	2348.7690
26	917.31900	0.00109	0.30033	3.32970	0.00033	3054.3980
27	1192.51400	0.00084	0.30025	3.33054	0.00025	3971.7170
28	1550.26700	0.00065	0.30019	3.33118	0.00019	5164.2220
29	2015.34600	0.00050	0.30015	3.33168	0.00015	6714.4880
30	2619.94900	0.00038	0.30011	3.33206	0.00011	8729.8280
31	3405.93200	0.00029	0.30009	3.33235	0.00009	11349.7700
32	4427.70700	0.00023	0.30007	3.33258	0.00007	14755.6800
33	5756.01500	0.00017	0.30005	3.33275	0.00005	19183.3800
34	7482.81600	0.00013	0.30004	3.33289	0.00004	24939.3900
35	9727.66000	0.00010	0.30003	3.33299	0.00003	32422.2000
36	**********	0.00008	0.30002	3.33307	0.00002	42149.8500
37	**********	0.00006	0.30002	3.33313	0.00002	54795.7600
38	**********	0.00005	0.30001	3.33318	0.00001	71235.3700
39	**********	0.00004	0.30001	3.33321	0.00001	92607.0000
40	**********	0.00003	0.30001	3.33324	0.00001	**********

SESSION 4: ENERGY PERFORMANCE OF THERMAL EQUIPMENT

INTRODUCTION

To determine energy conservation potential, it is necessary to evaluate the performance of energy-using equipment and systems. The accepted performance indicator is system efficiency. Energy efficiency can be defined as:

$$E = \frac{\text{Useful work}}{\text{Energy in}} .$$

Alternately, industrial energy efficiency can be defined as:

$$E = \text{Production per unit of energy consumption.}$$

Both definitions are used commonly by industry to evaluate its performance. The first definition is used when evaluating individual equipment performance; the second used in evaluating the overall operation of the plant.

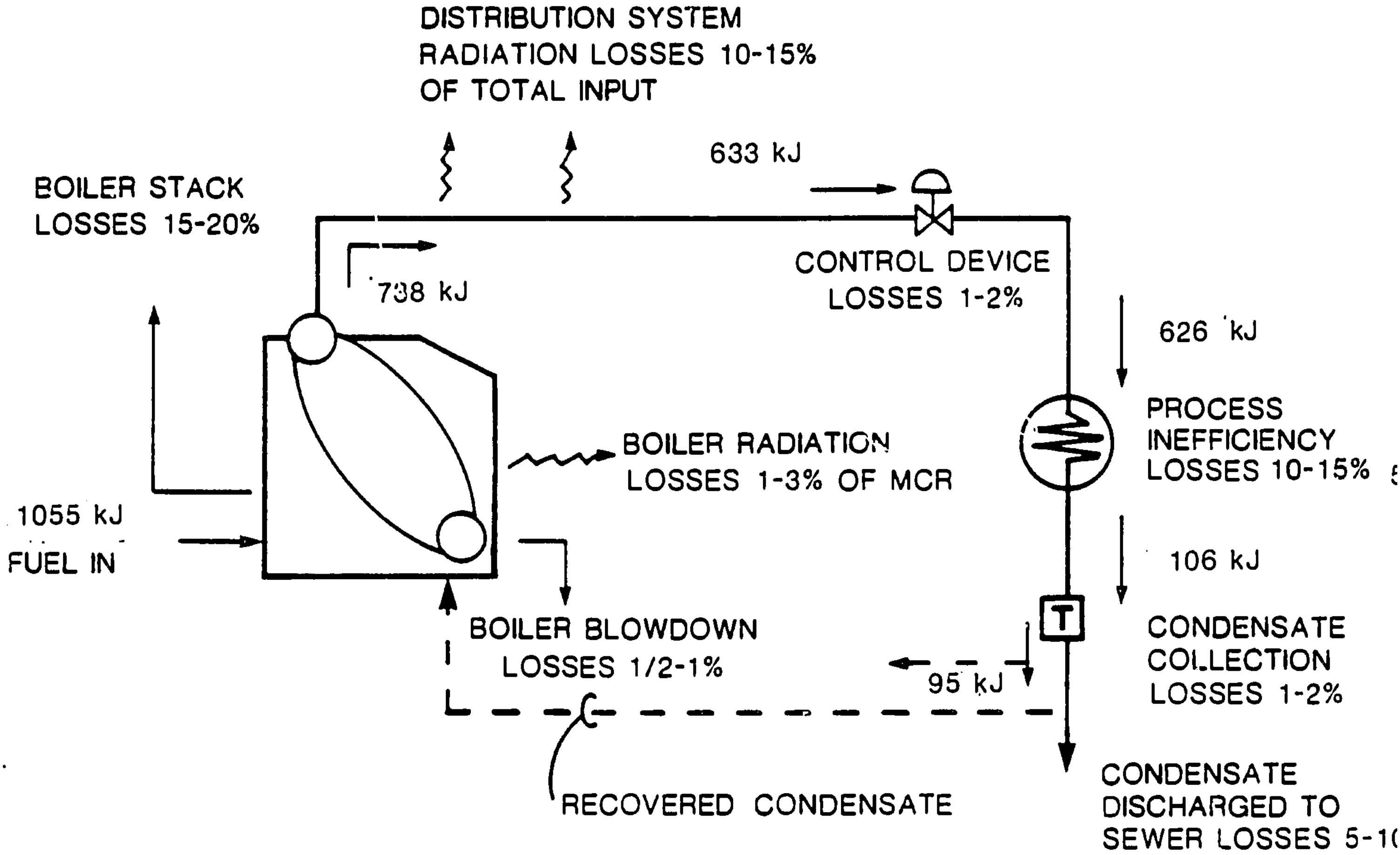
This session deals with equipment using fossil fuels. The basic functions and performance of various types of equipment are first described. An accepted indicator of efficiency is then given, together with an outline of how the efficiency can be determined.

It should be understood that overall plant energy performance is ultimately limited by the individual equipment operations; as such, neither can be treated in isolation. An example of the interaction is a steam generation and distribution system (see Exhibit 4.1). Each component of the system can be examined and its energy efficiency measured. However, the overall performance of the system can also be determined by considering all the individual elements and their relative efficiencies. As each step in the chain of energy use is made, the efficiency is found by multiplying successive efficiencies together, thereby decreasing the overall efficiency.

There are several types of equipment using fossil fuels commonly encountered in industry, including:

Exhibit 4.1

STEAM CYCLE EFFICIENCY



TOTAL SYSTEM LOSSES= 40% TO 50%

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- Burners
- Boilers
- Furnaces
- Dryers.

All of the above have their own efficiency and their performance characteristics are discussed below.

BURNERS

Function

A burner has four main functions:

- Mixing air and fuel to release the heat of combustion
- Establishing and maintaining a flame
- Positioning the flame in an area of useful heat release
- Controlling the heat release rate.

The prime function is to combine air (oxygen) and fuel to release the heat of combustion. Heat of combustion is called calorific value and is related to fuel composition. Air used in combustion generally has the same composition, so the major influence on burner design is fuel composition. Fossil fuels contain carbon, hydrogen, and sulfur in varying amounts. Hence, the amount of air required for perfect combustion varies from fuel to fuel. Exhibit 4.2 gives some typical data on common fossil fuels.

Combustion is an oxidation process, occurring naturally at ambient conditions. Under these conditions, the oxidation rate is limited; the reaction is not self-sustaining and ignition of the fuel does not occur. Ignition and self-sustaining combustion is readily identifiable as it manifests itself as a flame. An external source of energy, such as spark or flame, is needed to cause ignition and self-sustaining combustion. Hence, burners are designed to establish and maintain a flame without the need for an external energy source once initial ignition takes place.

Exhibit 4.2

Comparative Data (by Weight) for Some Typical Fuels

Fuel	Heating value: Btu/lb (and Btu/gal) Gross	Heating value: Btu/lb (and Btu/gal) Net	Heating value: kJ/kg (and kJ/kg) Gross	Heating value: kJ/kg (and kJ/kg) Net	Weighted air required per unit weight fuel	Weight of combustion products per weight of fuel and ft^3/gal: CO_2	H_2O	N_2	Total	Ultimate volume % CO_2 in dry flue gas
Natural gas	21,830	19,695	50,776	45,811	15.73	2.55	2.03	12.17	16.75	11.7
Propane, natural	21,573 (91,500)	19,886 (84,345)	27,879 (14,175)	25,700 (13,065)	15.35	3.01 (108.11)	1.62 (144.39)	12.01 (682.06)	16.64 (934.57)	13.8
Butane, refinery	20,810 (102,600)	19,183 (94,578)	26,893 (15,893)	24,791 (14,651)	15.00	3.04 (124.27)	1.53 (146.92)	11.83 (747.18)	16.39 (1,018.4)	14.3
Gasoline, motor	20,190 (123,361)	18,790 (114,807)	26,093 (19,110)	24,283 (17,785)	14.80	3.14 (165.1)	1.30 (166.8)	11.36 (940.3)	15.80 (1,272)	15.0
No. 2 distillate oil	18,993 (137,080)	17,855 (128,869)	24,546 (21,236)	23,074 (19,964)	14.35	3.20 (199.1)	1.12 (170.6)	10.95 (1,070)	15.27 (1,440)	15.7
No. 4 fuel oil	18,844 (143,010)	17,790 (135,013)	24,353 (22,153)	22,990 (20,915)	13.99	3.16 (206.7)	1.04 (166.1)	10.68 (1,097)	14.92 (1,472)	15.8
No. 6 residual oil	18,126 (153,120)	17,277 (145,947)	23,425 (23,721)	22,327 (22,609)	13.44	3.25 (236.4)	0.84 (149.0)	10.25 (1,172)	14.36 (1,558)	16.7
Wood, non-resinous	6,300		8,141		4.90	1.39	0.65	3.47	5.51	20.3
Coal, bituminous	14,030		18,131		10.81	2.94	0.49	8.26	11.71	18.5
Coal, anthracite	12,680		16,387		9.92	2.96	0.22	7.58	10.78	19.9
Coke	12,690		16,400		10.09	3.12	0.07	7.73	10.94	20.4

SOURCE: North American Combustion Handbook.

In the majority of cases, a burner provides heat that is to be transferred to a secondary source. Hence, the third function of the burner is to ensure that the flame produced is positioned at a point of useful heat release. Flames produced from burning different fuels differ in color, temperature, and size.

A burner must also regulate the heat release rate from the combustion process so that combustion is a controlled and safe operation while meeting the demand for heat.

Efficiency

Burner performance is evaluated by combustion efficiency.* Combustion efficiency is defined as:

$$\frac{\text{Energy input - total energy losses}}{\text{Energy input}}$$

where energy input = calorific value of fuel (gross basis)

energy losses = heat carried away in dry and wet flue gases, heat in unburned fuel, heat radiated to surroundings, and heat lost by direct contact with surroundings.

If fuel and air were mixed and burned in exact amounts so that all fuel and oxygen in the air were used, perfect combustion would occur, and the heat of combustion and flame temperature would be at maximum values. In practice, this situation (known as stoichiometric combustion) is not attained. Either too little or too much air is supplied to the burner; perfect combustion does not take place, and efficiency falls.

Both conditions are undesirable, as they are examples of energy inefficiency. Incomplete combustion where too much fuel is supplied is generally undesirable because, along with waste of energy, it can cause smoke, excess fouling of heat transfer surfaces, and under certain conditions a reducing atmosphere that will spoil a product.

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*The definition of combustion efficiency given here is not strictly true. Rather, it is what is conventionally understood as combustion efficiency.

Most common burners are designed to supply some excess air, which leads to some loss of efficiency but without the undesirable effects of smoke and fouling. Too much excess air can also be undesirable, as it can cause flame chilling and promote acid formation in the flue gases as well as high energy losses.

Combustion efficiency can be determined by a gas analysis of combustion products. A typical gas analysis will determine the quantities and temperature of carbon dioxide, carbon monoxide, and oxygen. More sophisticated analysis techniques also determine the quantities and temperatures of hydrocarbons, hydrogen, and sulfur dioxide.

Gas analysis can be completed using a variety of instruments. Some of these instruments are presented in detail in Session 9. A common method used works on the principle of selective absorption of the gases by chemical solutions. Such instruments give the percentage by volume of the various flue gases components.

Alternately, instruments that work by sensing changes in conductivity caused by the cooling effect of gases can be used. These instruments require regular maintenance and calibration to remain accurate. Because of this, they are not commonly used in energy audit work.

Zirconium oxide sensors that produce variable voltage outputs in relation to changes in the amount of oxygen in flue gases are becoming popular. This method is particularly useful, as in the relation between excess air and measured oxygen concentration is not greatly fuel dependent. In addition, to use as analyzers, this type of sensor can be employed as part of a combustion control system.

Gas temperatures are usually measured by a thermocouple or resistance thermometer. More sophisticated gas analyzers incorporate a temperature measuring element as part of the sensor.

After completing a flue gas analysis and measurement of the combustion air temperature, it is possible to calculate the energy losses resulting from non-stoichiometric combustion. As burners are used in association with other energy-using equipment (e.g., a boiler), the losses due to radiation to the surroundings are not normally considered when evaluating burner performance. However, these losses are important when evaluating the performance of the other equipment.

BOILERS

Function

The function of a boiler is to transfer heat from sources such as burners or hot waste gas streams to fluids, such as water, to produce steam or hot water. An example of energy flow in a boiler system is shown in Exhibit 4.3.

Boilers can be considered as heat exchangers. Typically, they account for 50 percent of industrial energy use. Energy is not always directly available in a form and at a point that can be used. It is necessary to convert primary energy to secondary energy and then transport it to where it can be usefully employed. Boilers became major energy users because, in the beginning of industrialization, water provided a relatively inexpensive but efficient method of transporting energy.

Steam boilers are important, and subsequent discussion will focus on them. Hot water and thermal fluid boilers have similar characteristics, and many points raised are applicable to them as well as to steam boilers.

The boiling point of water can be delayed by increasing pressure. The temperature is increased, thereby raising the heat content of a given amount of steam. Hence, more energy per unit mass can be transported. Two types of boiler were eventually developed to cope with increasing pressure: the firetube or shell boiler, and the watertube boiler. As the names imply, the water is contained in a shell in one and passes through tubes in the other. Thermal fluid boilers are essentially of the shell/firetube types. The temperature of a specifically chosen thermal fluid is raised in the boiler, but the fluid is not normally vaporized unlike a steam boiler. The thermal fluid is then circulated to the heat loads and then returned to the boiler after giving up its heat. Types of boilers and the fluids used are discussed in more detail in Sessions 11 and 14.

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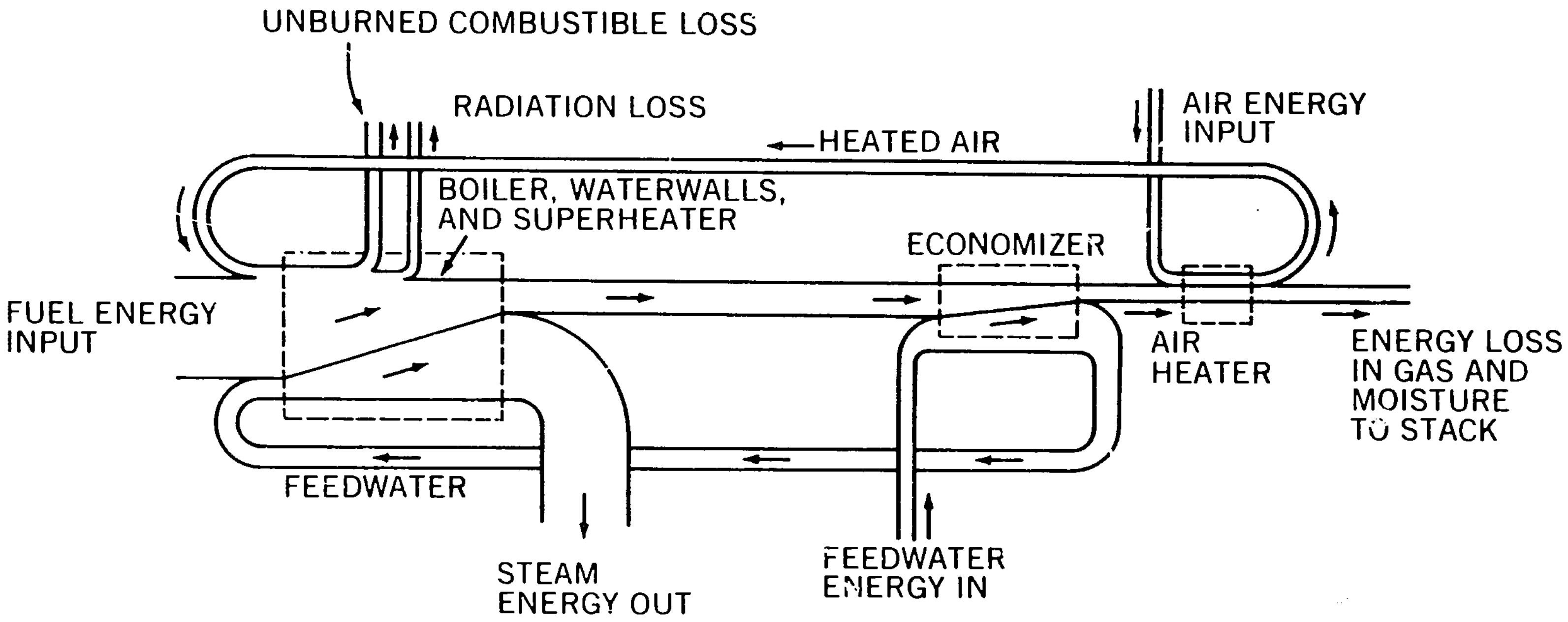
Exhibit 4.3



ENERGY FLOW IN A BOILER SYSTEM

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Efficiency

The efficiency of a boiler is defined as:

$$\text{Thermal efficiency} = \frac{\text{Energy in fluid out of boiler}}{\text{Energy supplied to boiler}} .$$

For steam generating boilers, this is:

$$\frac{\text{Evaporation ratio x heat content of steam at boiler pressure}}{\text{Calorific value}}$$

where evaporation ratio	=	amount of steam per unit of fuel used (kg/kg)
heat content of steam	=	heat of steam above feedwater heat content (kJ/kg)
calorific value	=	heat content of fuel (kJ/kg).

Boiler thermal efficiency can be determined in two ways. One method is relatively simple and involves a flue gas analysis similar to that for determining combustion efficiency. The second method involves the use of installed flow meters for measuring steam produced steam pressure, feedwater flow, feedwater temperature, fuel use, and raw water makeup. Conditions are monitored over a period of time, and subsequently, the thermal efficiency can be determined. Metering instrumentation may not be used by the energy auditor who is making an initial evaluation. Plants sometimes have installed most, if not all, of the above metering. Where this is the case, regular monitoring of the meters will give the most accurate indication of efficiency.

If suitable metering is not available, boiler efficiency can be assessed by a loss method based essentially upon a flue gas analysis. The losses are subtracted from the heat input giving the output, and efficiency is expressed as the ratio of output to input. Losses that are measured are losses owing to sensible heat in the exit gases, losses owing to latent heat in the exit gases, losses owing to incomplete combustion, losses from external surfaces of the boiler, and losses owing to boiler blowdown.

Instrumentation used is similar to those for determining combustion efficiency. Additional instrumentation is required to get data relating to radiation losses from the external surface of the boiler and to obtain information to estimate the blowdown rate from the boiler.

Radiation losses occur because the outer surfaces of the boiler are at a higher temperature than their surroundings. It is necessary to measure the temperature of the surface of the boiler and the ambient air temperature. Because boilers operate at fairly constant pressure/temperature, the radiation loss is essentially a constant quantity of heat irrespective of load. As a percentage of the heat input, the radiation loss varies inversely with the load, so this form of loss becomes larger at low loads. For example, a 1-percent radiation loss at full load becomes 2 percent at half load and 4 percent at a quarter load. Exhibit 4.4 shows the efficiency variation with load. The effect of radiation loss begins to become significant at loads less than 25 percent of the full load.

Typical blowdown losses can be determined from the dissolved solids level of boiler feedwater and boiler shell or drum water. Dissolved solids in boiler water form scale on heat transfer surfaces of a boiler, thereby reducing heat transfer from products of combustion to the water. Boilers are fitted with blowdown valves that are opened at regular intervals to remove water directly from the shell of the boiler to reduce the level of dissolved solids. Obviously, a compromise between the amount of blowdown and dissolved solids is required for efficient operation. Recommended standards for different boiler operating conditions are shown in Exhibit 4.5.

Boiler water and feedwater conditions are checked using an electrical conductivity device. It is necessary to cool the boiler water sample to the same temperature as the feedwater, as conductivity varies not only with dissolved solids concentration but also with temperature.

FURNACES

Function

The function of a furnace is to heat materials. There are two distinct purposes for operating furnaces. One is to bring about a chemical change or change of state in the material. The second purpose is to heat the material to a temperature where physical but not chemical changes occur. Examples of the first type of furnace operation include glass smelting, vitrification of ceramic products, or coking of coal. Examples of the second type include heat treatment furnaces.

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Exhibit 4.4

Boiler Efficiency - Load Curve

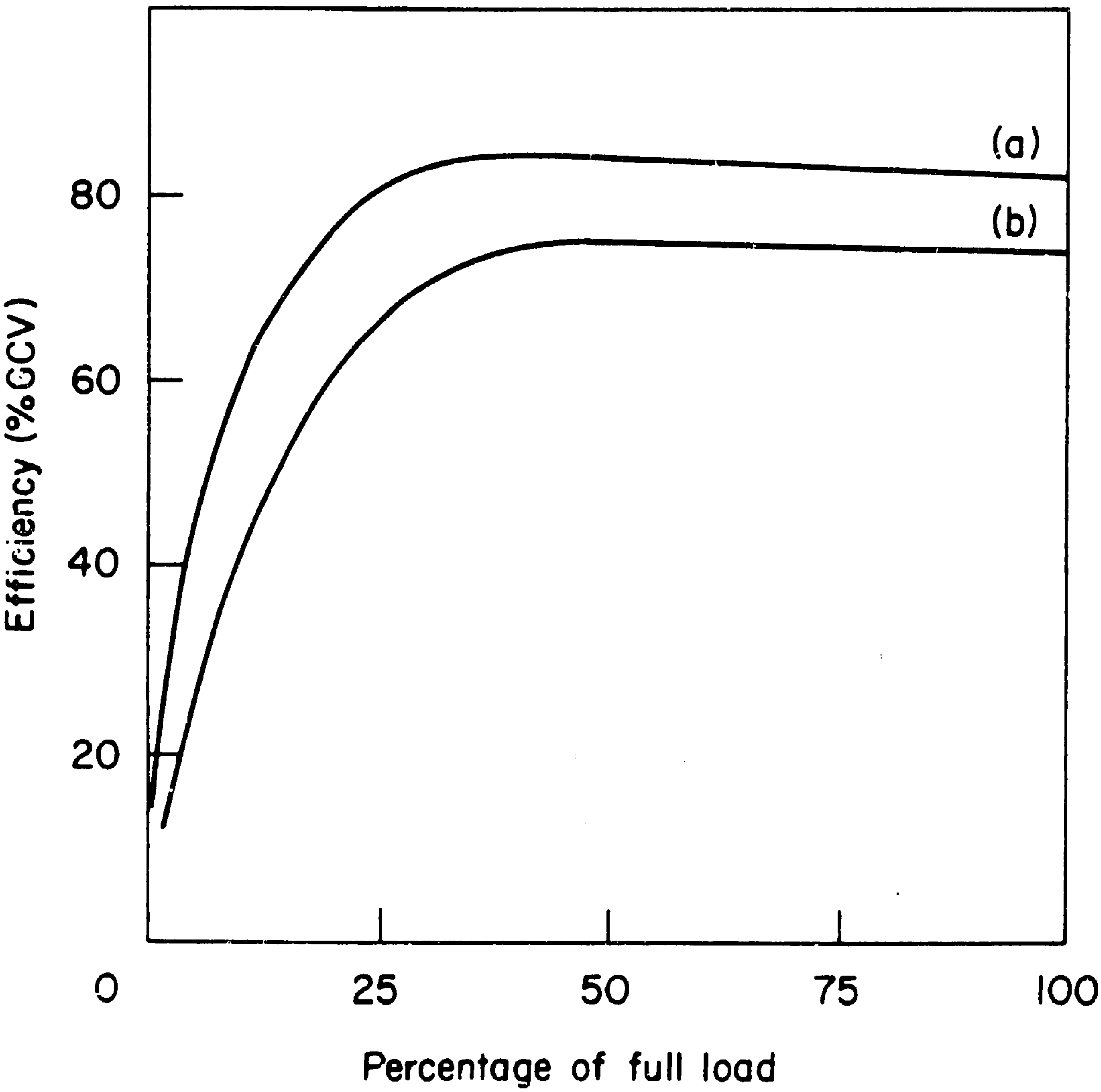


Exhibit 4.5

Recommended Total Dissolved Solids (TDS) Levels for Boilers

Type of boiler	Psi	Bar	TDS (ppm)
Packaged firetube			3,500
Vertical			3,500
Watertube			
	0-200	0-13.8	4,000
	201-600	13.8-20.7	3,500
	301-600	20.7-41.4	3,00-2,000
	601-900	20.7-62.1	2,000-1,400
	901-1,100	62.1-75.9	1,400-1,000
	1,100-1,500	75.9-103.5	1,000-750

Furnaces operate at relatively high temperatures. The temperature used depends partly on the material being heated and, for a given material, partly on the purpose of the heating process and subsequent operations.

Furnaces use two methods of obtaining high temperatures: combustion of fuel and conversion of electrical energy into heat. Fuel combustion is the more common method because of relative fuel cost differences. However, electricity can offer advantages that cannot be measured in terms of fuel cost, including faster heating (and thereby production rates), reduced fouling and slagging of heated material, and easier control.

Electricity is used in the following manner:

- Material to be heated acts as a resistance heater
- Separate resistance heaters use traditional heat transfer methods to transfer heat
- Material is heated by induction.

This session covers the use of thermal equipment only, so electrical furnaces are not discussed further.

Furnaces are classified as either batch or continuous on the basis of operation. Batch furnaces operate at a constant furnace temperature, with the material or stock (in the same position throughout) the heating cycle, whereas continuous furnaces move stock through the furnace during the heating cycle. Specific furnace types and their operation are discussed in detail in Session 12.

Furnaces are constructed in a similar manner. They have a hearth, on which the stock is heated, walls, and a roof. To prevent overheating of the furnace foundation and the hearth, often the hearth is ventilated. In continuous furnaces, the means of passing the material through the furnace forms an integral part, if not all, of the hearth. An example is the deck of a kiln car on which stock is placed. The deck is made of refractory, and adjacent cars abut to form a continuous hearth. Fuel and air are supplied through burners or through ports. Burners fire through burner tubes, and combustion products are exhausted via vents and flues to the stack. Furnaces are built using firebrick and insulating materials or lightweight firebrick that can be used to reduce heat losses.

Efficiency

A similar measure of efficiency to that of a boiler is used for furnaces. Furnace efficiency is defined:

$$\text{Efficiency} = \frac{\text{Heat in stock}}{\text{Heat input from fuel}} .$$

The heat in the stock is calculated from stock temperature -- measured by pyrometer -- the thermal properties, and mass of the stock. This information is related to the fuel consumed to calculate the efficiency. Thermal efficiencies or heat balances are often presented pictorially in a Sankey diagram. An example is shown in Exhibit 4.6.

Calculating furnace efficiency yields low thermal efficiencies when compared to other equipment. Typical boiler thermal efficiencies can range from 60 to 90 percent, whereas furnace efficiencies can be as low as 5 percent and typically range from 15 to 45 percent. A better indicator of furnace efficiency is the energy consumption per unit of output.

One of the main reasons for the relative inefficiency of furnaces is the relative temperature differences involved in the material heated. Heat transfer can only take place from a hot to a cold sink; hence, furnace exit gases must be at a high temperature if the stock is to be heated to a high required temperature. Exhibit 4.7 indicates typical heating temperatures in furnaces. The range is 149°C to 1,427°C, whereas process boilers operate primarily at temperatures of 149°C to 260°C.

Alternatively, furnace efficiency can be calculated by estimating losses, namely flue gas and walls losses. The heat content of furnace exhaust gases can be determined by flue gas analysis and an air flow measurement. Care must be taken when making a gas analysis of furnaces because high excess air rates are sometimes used in furnace operations. Excess air levels of 200 percent and above cause inaccuracies in the gas

Exhibit 4.6

Sankey Diagram of Furnace Heat Balance

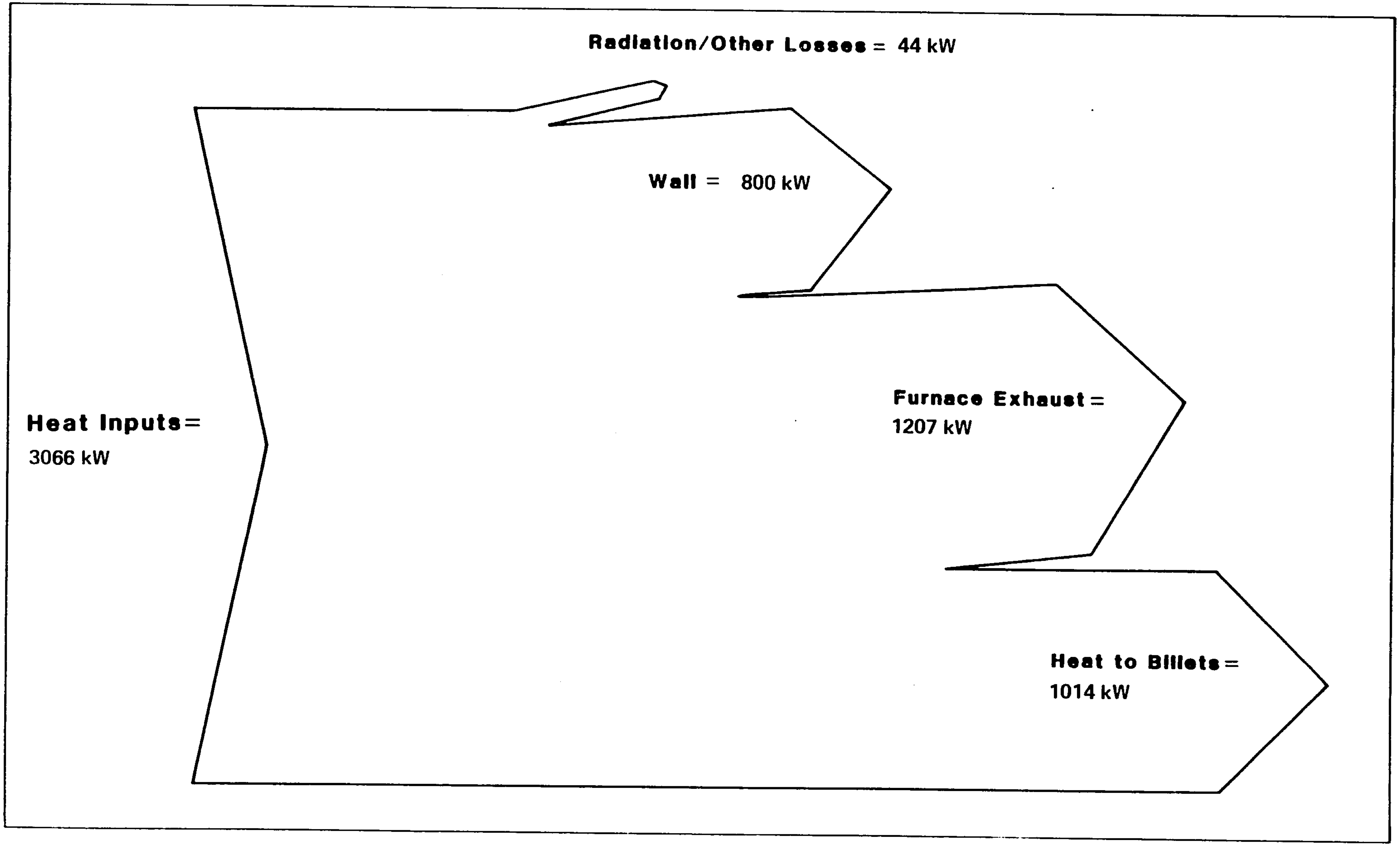


Exhibit 4.7

Temperature Requirements in Furnace Operations

Heating process or subsequent operation	Highest temperature during heating process	
	°C	(°F)
Drying steel wire	149	(300)
Drying lacquer	149	(300)
Tempering in oil	260	(500)
Tempering high-speed steel	332	(630)
Annealing aluminum	399	(750)
Cracking petroleum	399	(750)
Heating aluminum for rolling	454	(850)
Annealing glass	621	(1,150)
Annealing copper	621	(1,150)
Strain relieving	649-704	(1,200-1,300)
Heating brass for rolling	787	(1,450)
Annealing high-carbon steel	816	(1,500)
Glazing porcelain	999	(1,830)
Glost-firing porcelain	1,121	(2,050)
Bisque-firing porcelain	1,232	(2,250)
Calcining limestone	1,371	(2,500)
Burning firebrick	1,315-1,482	(2,400-2,700)
Burning portland cement	1,427	(2,600)
Glass melting	1,427	(2,600)

analysis. When these conditions occur, a direct measurement of flue gas flow rate and temperature must be done.

Wall losses are dependent on furnace operation. If a furnace operates continuously, steady-state heat transfer conditions exist. The heat loss can be calculated as follows:

$$Q = \frac{C\ (T_i - T_o)}{S} = K\ (T_o - T_a)$$

where Q = heat transmitted (W/m^2)

T_i = temperature of inside wall (^oC)

To = temperature of outside wall (^oC)

Ta = air temperature (^oC)

C = conductivity of wall material ($W/m\ ^oC$)

C = coefficient of heat dissipation from outer surface ($W/m^2\ ^oC$)

S = wall thickness (m).

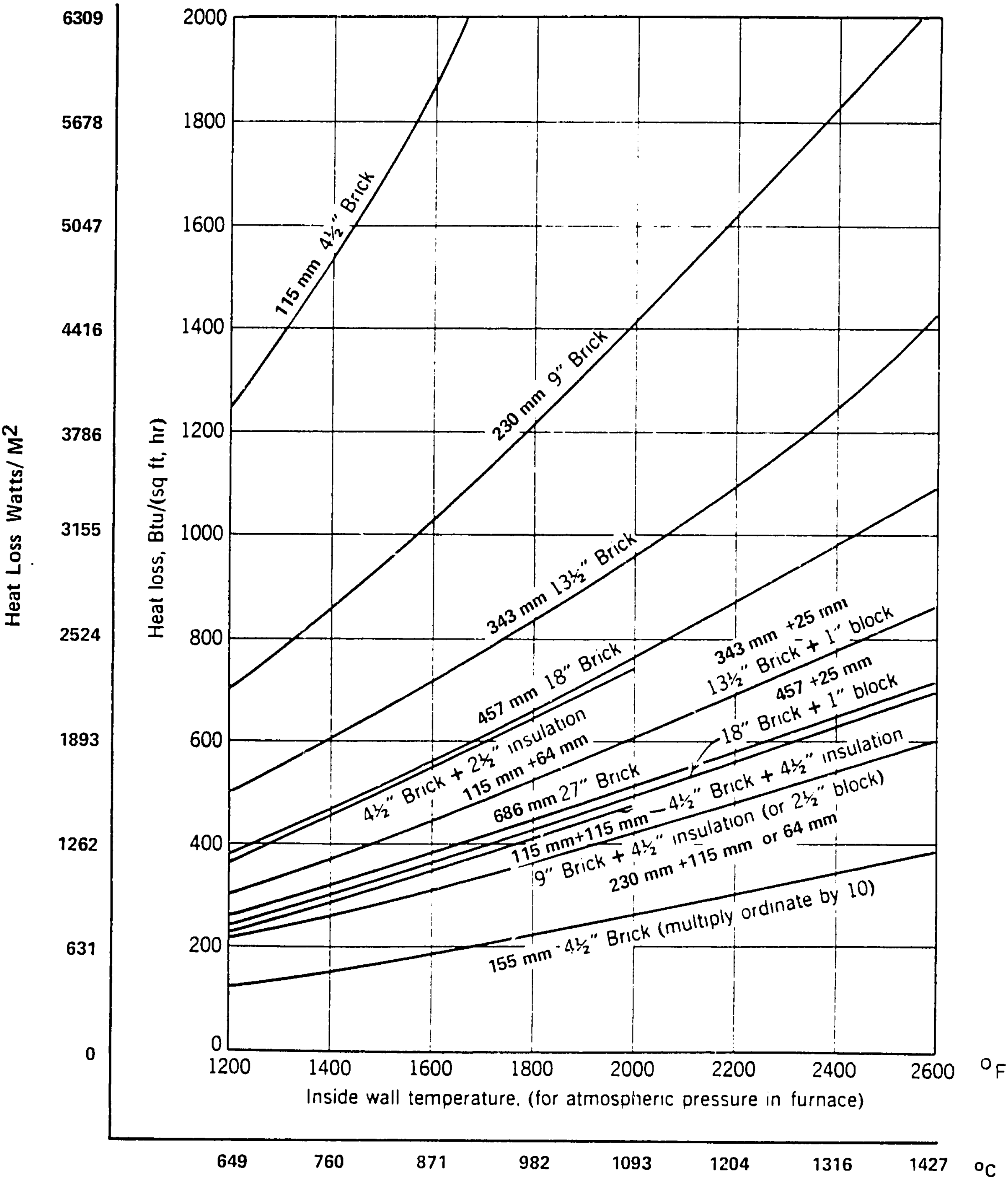
Because of the relative importance of furnaces and common construction materials, charts have been developed based on various inside wall temperatures. A sample is shown in Exhibit 4.8, where wall losses can be predicted by measurement of the inside wall surface temperature.

The wall surface temperature can be measured using an infrared pyrometer. Pyrometers are hand-held instruments that measure radiation from hot surfaces. They can measure temperatures in the range of 1,649^{o}C to 2,760^{o}C. The pyrometer is pointed at the hot surface, and the radiant energy from the surface acts on a sensitive actuating thermocouple, thereby causing a small voltage to be generated. The voltage is given directly by the instrument as a temperature.

When using the instrument, care must be taken to ensure that potential radiation absorbers such as the furnace gas atmosphere or glass in spy holes do not absorb too much radiation or that non-black-body radiation conditions do not exist. Pyrometers must be handled very carefully, kept clean, and calibrated at regular intervals. Care must also be taken not to overexpose them to radiation.

Exhibit 4.8

Heat Losses Through Furnace Walls



Heat losses from the structure of the furnace also occur owing to intermittent operations. The furnace structure stores a certain amount of energy that does not dissipate when the furnace is in continuous operation. This is reduced by limiting the thermal capacity of the structure. Furnaces that are operated for a short periods followed by long idle periods can be built with thin walls of insulating refractory.

Estimating this loss requires consideration of furnace cycle time and the ratio of operating hours to idling hours. An exact calculation is complex, and in practice is rarely completed. An approximation can be made by using a chart from a chart, such as that shown in Exhibit 4.9, that shows intermittent loss as a percentage of steady-state wall loss. The chart shown uses certain parameters (i.e., a time ratio and a physical property ratio) that can easily be calculated and expresses their relationship graphically.

The ratio of time is calculated on a cyclic basis such as weekly or monthly. The ratio used is:

$$\text{Ratio} = \frac{\text{Operating time}}{\text{Operating time + dead time}}$$

where dead time = hours that furnace is shut down or idle.

The numbers on the curves denote the dimensionless physical property ratio:

$$\frac{\text{Diffusivity of wall material x length of cycle}}{(\text{Wall thickness})^2}\;.$$

Properties of refractory materials are contained in Exhibit 4.10.

Two other areas of loss from a furnace are losses owing to radiation from openings and losses owing to furnace gases escaping around doors. These losses are usually small and are controllable, to a certain extent. Openings can be kept to a minimum and door seals kept in a good state of repair.

Exhibit 4.9

Estimating Intermittent Wall Loss Chart

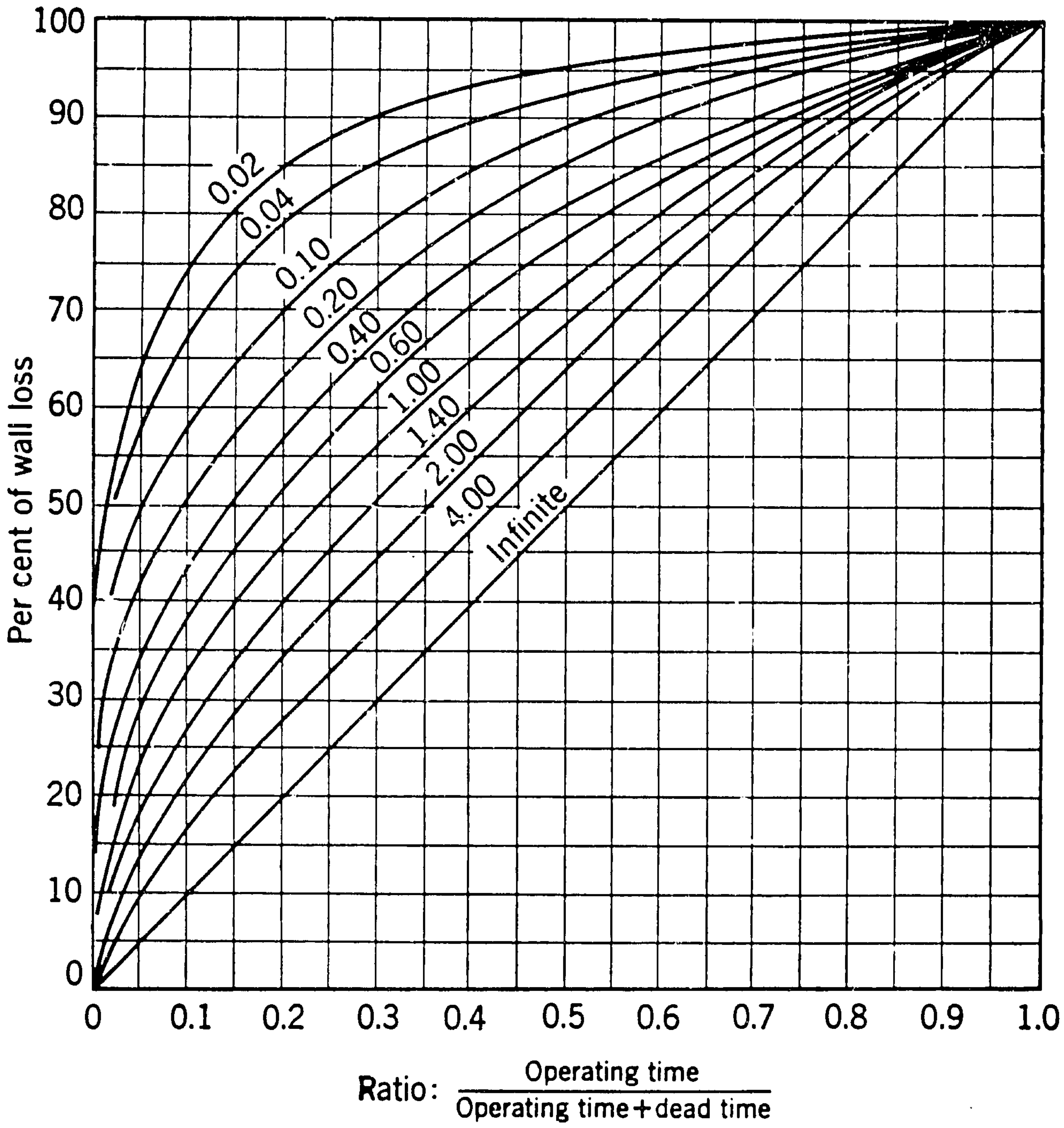


Exhibit 4.10

Properties of Refractories

Brick type	Average density, pcf	Specific heat at temperature T, or (mean between) $0^{o}F$ and $T^{o}F$)	Diffusivity, ft^2/hr
Fireclay brick	120-130	(0.20 + 0.000035 T)	0.0204 at 1,400°F
Silica brick	105-125	(0.19 + 0.000039 T)	0.0262 at 1,400°F
Red brick	(110 soft burned) (139 hard burned)	0.200 at 500°F	
Silicon carbide	130-155	0.18 at room temp.	0.233 at 2,000°F
Magnesite	160-165	(0.255 + 0.000033 T)	0.0455 at 1,400°F
Sillimanite bricks	150-156	0.20 at room temp.	
Mullite bricks	135-180		
Kaolin bricks	130	(0.20 + 0.000031 T)	
Chrome bricks	180-195	(0.18 + 0.000019 T)	0.023 at 1,400°F
Concrete bricks (tamped, 1:2:5)	150	(0.156 at 140°F) (0.219 at 770°F)	0.0304 at 400°F
Diatomaceous bricks	25-30	0.18 at 1,000°F	0.017 at 700°F
Calcined diatomaceous bricks	36-44	(0.17 + 0.00003 T)	0.0193 at 1,000°F
Lightweight (insulating) firebricks	32-55	Same as fireclay	

T = temperature, °F.

Conversion factors: Btu/lb = 2.328 kJ/kg
ft^2 = 0.0929 m^2
°F = °C; subtract 32; multiply by 5/9.

DRYERS

Function

The basic function of a dryer is to remove volatile substances from materials by thermal means to:

- Produce a material in a desired condition for further processing, handling, or sale
- Reduce its bulk or weight for economic further processing, handling, or transportation
- Recover byproducts from slurries or solutions
- Sterilize or preserve the product.

Drying is completed in several ways:

- Evaporation, either by direct heating or by air drying
- Dehydration and freeze drying
- Dielectric drying.

Many materials are dried, including paint, paper and fiberboard, foodstuffs and pharmaceutical products, ceramics, cement, enameled products, and textile goods.

Dryers operate either on a batch or continuous basis. Essentially, dryers can be classified either as convection dryers, or contact or conduction dryers. Examples are given in Exhibit 4.11, and are discussed in more detail in Session 13.

Convection dryers are sometimes referred to as direct dryers because the evaporating medium, usually air or hot gases, impinges upon or makes direct contact with the material to be dried. Contact or conduction dryers are occasionally referred to as indirect dryers because evaporation takes place after heat has been supplied by conduction through a metal wall or plate. The classification system is a broad one, and some dryers are a combination of both categories.

Exhibit 4.11

Types of Dryers

Dryer type	Principal mode of operation
Convection dryers	
Drying rooms	Batch, continuous, semi-continuous
Cabinet dryers (tray, etc.)	Batch
Conveyor dryers	Continuous
Tunnel dryers (truck)	Continuous, semi-continuous
Rotary dryers	Continuous
Vertical cylindrical dryers	Continuous
Spray dryers	Continuous
Air-swept rotary mills	Continuous
Pneumatic dryers	Continuous
Contact dryers	
Platen dryers	Batch
Cylindrical dryers	Continuous
Vacuum dryers	Batch
Freeze dryers	Batch
Specialized dryers	
E.g., fluidized-bed, radiant, high-frequency dryers	Batch, continuous, semi-continuous

There are two other types — the radiation dryer and the dielectric dryer, but these are not discussed here. Because most dryers deal with evaporation of water from a material, the efficiency presented is one for those evaporating water by thermal means.

Efficiency

The thermal efficiency of a dryer is expressed as:

$$\text{Efficiency} = \frac{\text{Heat required to evaporate fluid from material}}{\text{Fuel input}} \; .$$

In drying operations, heat must be supplied to:

- Heat the incoming air
- Warm the material being handled
- Heat up the water in the incoming material and evaporate it as required
- Make up for heat losses by convection, radiation, and air leakage.

When efficiency is considered, only heat used to remove water from the material is useful.

Dryer efficiency is sometimes expressed in terms of mass of water evaporated per unit of energy consumed. This definition can be misleading because final moisture contents vary with product specification. One of the major causes of energy waste is overdrying of product.

Dryer efficiency is determined by completing an energy or heat balance for the dryer. Completing a dryer heat balance involves measuring a number of different items and knowing certain properties of the material being dried. Information required includes:

- Material moisture content before and after dryer
- Fresh air dry bulb/wet bulb temperature
- Exhaust air dry bulb/wet bulb temperature
- Heat supply to heat fresh air
- Air flow rate

- Material specific heat
- Material throughput
- Material temperature before and after dryer.

Using the above information and psychrometric charts, it is possible to balance mass and energy flows through the dryer. Psychrometric charts are compilations of the properties of mixtures of air and water.

Psychrometric charts detail the following properties:

- Dry bulb temperature
- Wet bulb temperature
- Moisture content
- Percentage saturation
- Total heat of mixture
- Specific volume of mixture
- Dew point
- Vapor pressure.

Sample charts are presented in Exhibits 4.12 (with temperature scale in degrees Fahrenheit) and 4.13 (with temperature scale in degrees Celsius). The various curves shown enable other properties to be determined, provided two conditions are known.

Heat losses from the drying process are balanced by heat input. Hence, it is possible to determine the losses from the structure of the dryer by the difference.

Drying is a relatively common industrial process, and information on materials being dried is available from standard texts. Some specific heats of common materials are given in Exhibit 4.13. The moisture content of the material can be determined by taking a representative sample of the material before and after the dryer and weighing them. Both samples should then be dried until no more moisture can be removed from them. They are then reweighed. Hence, moisture contents for both samples can be determined.

Exhibit 4.12 **PSYCHROMETRIC CHART**
High Temperatures

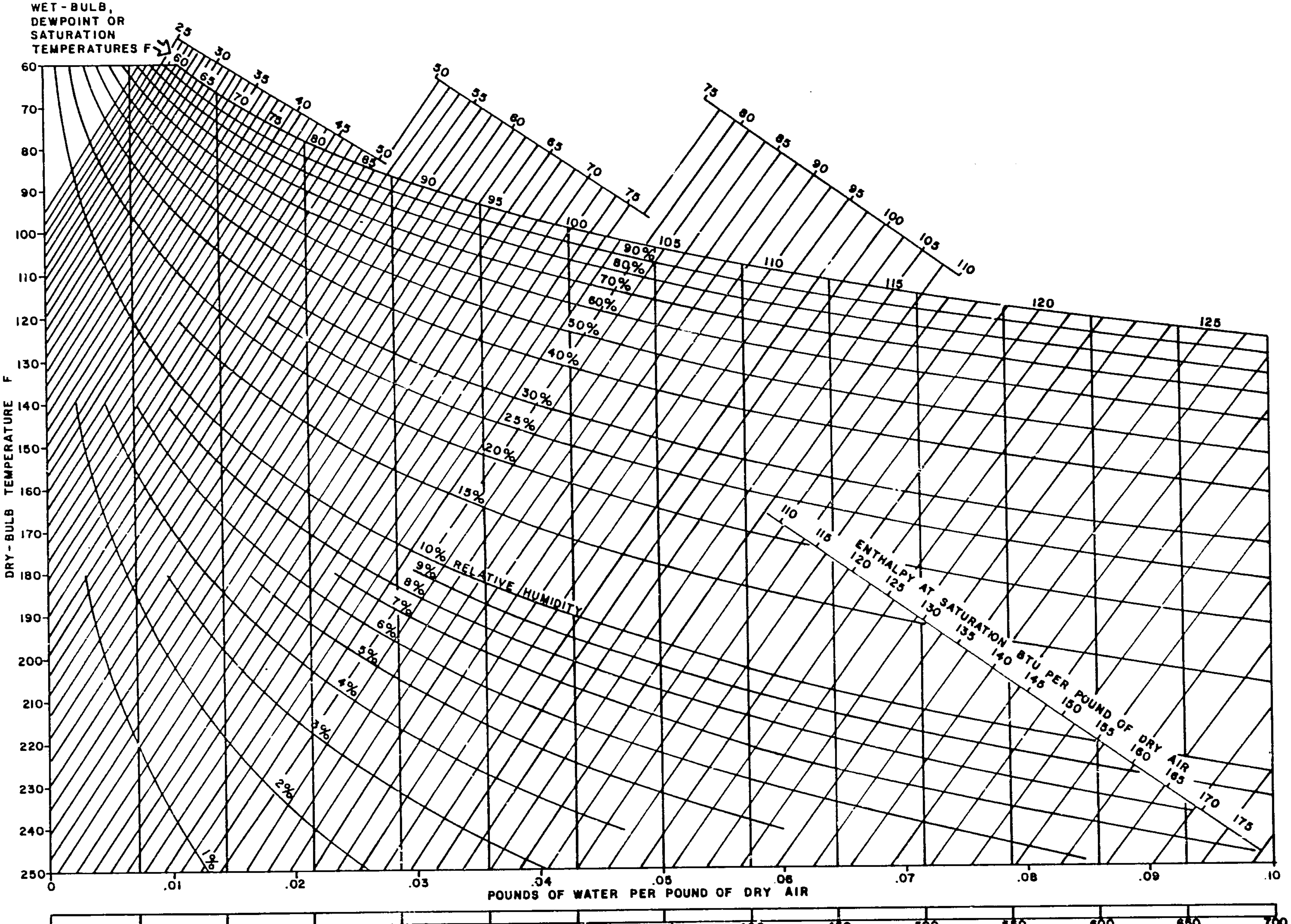


Exhibit 4.12
Psychrometric Chart (based on a Barometric of 1013.25 mbr)

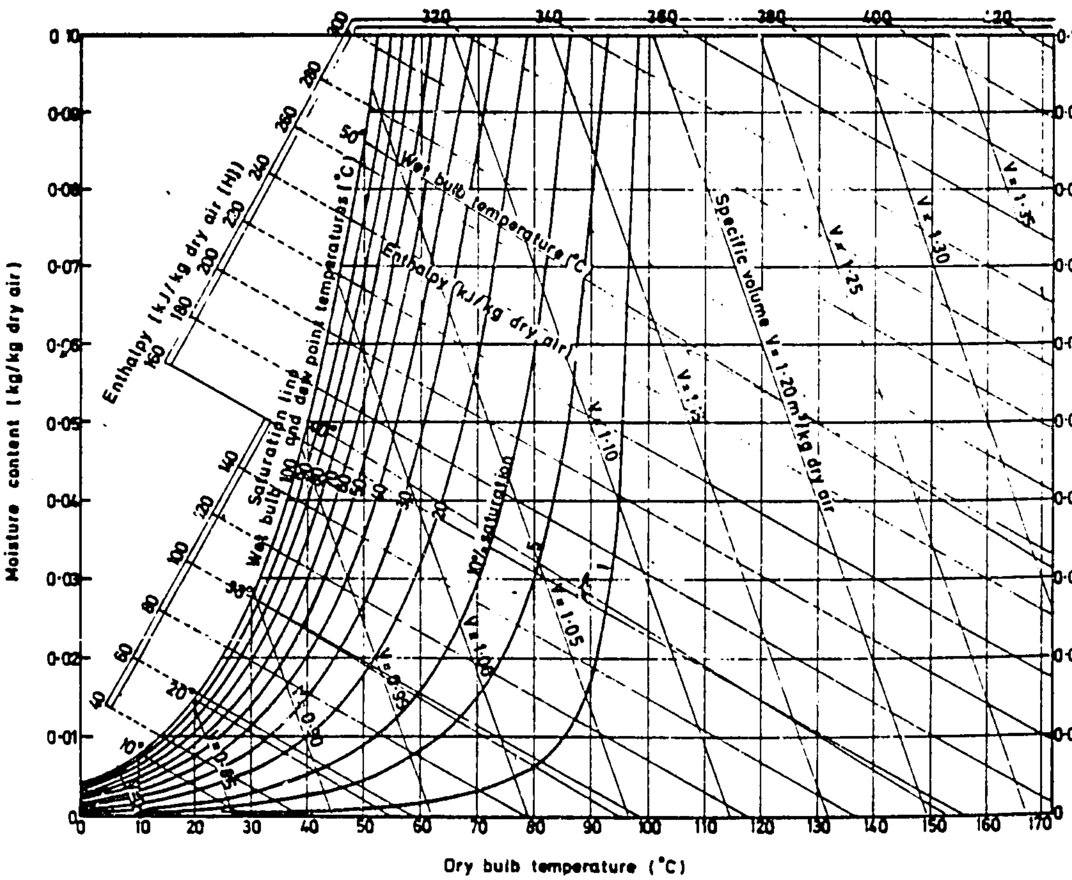


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Exhibit 4.13

Specific Heats of Common Materials

Material	Temperature °C	Specific heat at constant pressure cal/g/K
Air	Up to 300°C	0.248
Alumina	100°C	0.23
Alumina	1,500°C	0.27
Aluminum	Up to 100°C	0.23
Brickwork	--	0.2
Carborundum brick	Up to 100°C	0.16-0.20
Cellulose (dry)	--	0.32-0.37
Cement	--	0.19-0.20
Chalk	Up to 100°C	0.19
Charcoal	Up to 100°C	0.16-0.24
Clay (dry)	Up to 100°C	0.22
Coal	--	0.25
Coke	--	0.26
Concrete	Up to 156°C	0.16
Concrete	Up to 800°C	0.22
Copper	Up to 600°C	0.102
Cork	--	0.49
Firebrick	Up to 1,000°C	0.23-0.26
Flue gases (average)	Up to 350°C	0.24
Fuel oil	--	0.4-0.46
Gas oil		0.48-0.49
Glass silicate	Up to 100°C	0.19-0.20
Glass silicate	Up to 700°C	0.24-0.26
Glass wool	--	0.16
Graphite	--	0.2
Ice	-10°C	0.53
Ice	-60°C	0.39
Iron	Up to 400°C	0.13
Kerosene	--	0.47
Leather	--	0.36
Limestone	--	0.22
Magnesia brick	100°C	0.22
Magnesia brick	1,500°C	0.20
Mercury	--	0.033
Quartz	350°C	0.28
Rubber (vulcanized)	--	0.42
Rubber (loaded)	--	0.27-0.48
Salt (rock)	Up to 45°C	0.22
Silica brick	Up to 1,500°C	0.20-0.23
Silica (fused)	--	0.32
Silk	--	0.33
Steam	Up to 600°C	0.48
Stoneware	Up to 100°C	0.19
Sugar	20°C	0.27
Sulfur	--	0.20
Tin	--	0.055
Water	15°C	1.00
Wood (soft)	--	0.42-0.65
Wood (oak)	--	0.57

Moisture contents can be expressed in terms of either the "wet" or "dry" basis. However, the "dry" basis is a much less confusing indicator and should be used. The difference in moisture contents of the material samples is indicative of the amount of moisture removed in the dryer.

Air temperatures are measured using dry and wet bulb thermometers. A wet bulb thermometer is basically a dry bulb thermometer that is covered with a wet cloth (see Session 9). The wet bulb temperature is the dynamic equilibrium temperature reached by a water surface exposed to air when the transfer rate from the air to the water equals the rate at which the latent heat of water evaporated is carried back to the air stream.

Air flow in the dryer can be measured by use of a pitot tube. The pitot tube is basically a velocity measuring device and measures the impact pressure of the air flow as the difference between the sum of static and impact pressure and static pressure alone. Because the velocity profile is not uniform across a duct, it is necessary to traverse the duct and take a series of point readings, which are then averaged. By virtue of knowing the velocity and the duct geometry, the air flow rate can be determined.

Industrial boilers: What's happening today

Pollution control, operator training, and fuel handling are just some of the problems generated by the massive move to coal and waste fuels

Coal, coal, and yet more coal is what's happening to industrial boilers today. While existing oil-designed industrial packaged boilers are unsuitable for burning this fuel, coal-designed boilers that 15 years ago were converted to oil or gas are fast reverting to the lower-cost fuel. But wherever new steam-generating facilities are planned, the economics of coal is overwhelming. Even a petroleum-refining facility has installed its first coal-fired unit.

This rush to coal is not without its problems, however, not the least of which is the absence of coal-firing experience among today's operators and supervisors, most of whom were raised on oil. Two papers at the ASME Industrial Power Conference address this problem, while still another covers experience firing the still more difficult refuse-derived fuel. In this latter case, the boiler is also designed to burn coal, which now becomes the premium fuel.

Oil refinery installs coal-fired boiler system

By **W R Ketterman,** CRA Inc, and **D A Heinzmann,** McBurney Corp

A coal-fired steam plant is a different kettle of fish to build and operate from one firing oil or gas. In 1977, CRA Inc decided to proceed with the installation of a 190,000-lb/hr, 650-psig, coal-fired boiler at its Coffeyville (Kan) refinery to replace oil and gas firing for the production of steam.

Specifications were initially prepared for two 150,000-lb/hr boilers and quotation requests made to firms that would engineer and construct the boiler-related equipment, while CRA personnel retained control for installation of feedwater, yard coal handling, site preparation, and utility tie-ins. The quoted cost for two boilers was too high, and a revised project bid was requested for one 190,000-lb/hr, 650-psig/596F steam generator. Because of the lower cost for one larger unit, a single boiler was selected and a turnkey engineering/construction order placed.

The boiler system included a coal-yard hopper for truck unloading, a coal silo, coal scale boiler, traveling-grate spreader stoker, pneumatic ash disposal, fabic filter, and ash silo. Additional equipment included deaerator, boiler-feed pumps, rail unloading system, and a dragline coal-storage/reclaim system.

Provisions in the plot plan were made for a future boiler and for future dry SO_2 removal.

Spreader stoker vs pulverized coal. It was decided that the added first cost involved with a pulverized-coal-fired plant over a spreader-stoker-fired plant could not be justified by the difference in coal costs and the higher efficiency normally expected with a pulverized-coal unit. In addition, CRA had been firing the easy fuels of natural gas, refinery gas, and fuel oil in its steam plant, and the switch to coal firing by spreader stoker was felt to be less prone to disastrous explosions in the ductwork and firebox than a pulverized-coal system.

Industrial Power Conference Report

Fabric filter vs precipitator. The installed costs for a fabric filter were determined to be lower than for an electrostatic precipitator. In addition, performance of the bag filter for coal with varying sulfur content was expected to be superior. At the time that CRA prepared specifications, the coal source was not known, and four different coals with varying properties were specified for use.

In addition to major equipment and systems, the following items are pertinent to the installation:

An economizer is used to reduce boiler exit-gas temperatures to 336F at the 190,000-lb/hr rating. There is no air heater. The stack temperature is as low as was felt practical without causing sulfur corrosion in the economizer, ductwork, and fabric filter. Provisions were made for future air preheat with boiler blowdown or exhaust steam.

Steam turbines are used extensively in the installation and include: induced-draft-fan drive, forced-draft-fan drive, one feedwater-pump drive, backup drive on hydraulic system to power traveling grate, and backup drive for coal distributors.

There is no mechanical collector included in the installation. The collector would have added pressure drop to the system without adding to the particulate-removal efficiency. The flue gas from the

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Power, October 1982

economizer enters directly into the fabric filter.

The steam-plant installation is outdoors, with only the control-room enclosure to house items of instrumentation and control.

A steam-jet ejector, rather than a vacuum pump, was selected to establish a vacuum on the ash-handling system. Uncertainty of vacuum-pump durability in the ash service, together with higher initial cost, entered into the decision for use of a steam ejector.

The gas-to-cloth ratio on the fabric filter with all the modules in service is 1.65:1. With one module in cleaning with reverse air, the gas-to-cloth ratio is 2.28:1. This gas-to-cloth ratio is conservative and was expected to provide moderate pressure drop and full capacity with one compartment off line.

Four different coals were specified by analysis as the design basis for the unit. The boiler manufacturer based the design on the worst coal in terms of ash content, heating value, slagging, and fouling conditions. The stack is 150 ft above grade and gunnite lined to reduce corrosion. Stack material is Corten. Sample ports and platforms are located at 60 ft and 100 ft.

The coal-fired boiler was placed in operation in June 1981, after approximately two months of startup, testing, and checkout of all equipment. One delay that was much longer than expected, and not foreseen originally to be a problem, was the testing of steam-drum relief valves. Relief-valve seats were damaged and had to be remachined before reseating could be accomplished. The delay afforded several weeks of operator instruction while final details of the boiler system were completed.

Refinery steam balance is affected substantially by the introduction of 650-psig steam into a plant system that was formerly operated on 275-psig, 150-psig, and 10-psig steam. Eight turbines were installed to drive continuously operating equipment and to reduce 650-psig steam to 150 psig. A pressure controller for 650-psig to 275-psig steam was installed to supplement the 275-psig boiler system. It appears that the originally planned steam balance may be nearly correct.

However, if operating problems or other factors cause the 650-psig boiler supply to be shut down, the disruption of operations would be substantial. Changes would have to be made to standby equipment, not operating at 650-psig, in order to maintain operation of the refinery. Dual-pressure turbines have solved a part of this problem, but quick response with manual changing of large valves is a must to maintain the process operation.

Operating and maintaining a coal-fired boiler is more complex and expensive than operating a gas- or oil-fired unit. The fabric-filter system has been exceedingly effective. Only five of 1116 bags have failed in 10 months. Pressure drop is nominal. The stack gases are not visible, having a normal opacity of 2-3%.

The boiler is completely instrumented and has a full complement of shut-down devices intended to provide safety to the equipment and operators. This high degree of instrumentation created a need for more instrumentation maintenance and attention than would be normal on a less completely instrumented installation.

During the nine months the boiler system has been in operation, operators who had never seen a coal-fired boiler, and only one of whom had operated a boiler system before, have received a liberal education in the operation of the system. It is apparent that the tempering period over the past year has produced a capable, experienced operating group that reacts to system demands to maintain competent operation.

Training is key to startup of new coal-fired powerhouse

By **F W Scott** and **H G Ruiter,** Du Pont Co

A high degree of teamwork between Du Pont Co's Central Engineering Dept and its local operating department was essential for the successful installation of a new \$40-million pulverized-coal-fired facility at Cape Fear, NC. Two 185,000-lb/hr, 700-psig, field-erected boilers were planned to replace packaged boilers burning No. 6 oil.

Normally, local operating departments do not have the responsibility nor the expertise to design this kind of facility. The Central Engineering Dept was responsible for design of the powerhouse. But as design neared completion, the operating department participated in design reviews and vendor selection. The actual situation at a plant has a good deal of impact on design. For example, at Cape Fear, the second and third shifts are without supervision, and only a small maintenance crew covers the entire site. Obviously, this situation has an important bearing on design, which must incorporate enough redundancy in pumps, controls, etc, to provide continuity when something malfunctions.

A second example has to do with control schemes. In the marketplace today, a varying degree of automation is available on burner-management systems and boiler controls. The operating-department philosophy needs to be considered as decisions are made about these systems.

A good job in design liaison requires a careful balance between too much and too little involvement. Too much can quickly run up costs and delay schedules. Too little or tardy involvement can have the same effect because of late design changes.

Training of operating and maintenance personnel is the most important prestartup task. A perfectly designed and constructed facility will have problems with safety and continuity if the people operating and maintaining it are not properly trained. This was the largest task at Cape Fear since there was very little coal-burning expertise among supervisory personnel and no previous coal-burning experience among operators and mechanics.

The approach and commitment to training was to assign people to the project early and to seek the best training available. Supervisors were assigned 12-18 months prior to startup; mechanics and operators were available for training nine months before startup.

The first step in organizing training was to develop individual technical development programs for each member of the supervisory staff assigned to the startup team. The individual, together with his supervisor, developed this program and reviewed it monthly to monitor progress and make refinements as more information became available. Next, training programs were developed for operators, control technicians, and mechanical technicians. Each program consisted of some 400 hours of organized training.

The supervisory staff visited similar installations to get ideas for design improvement. Most facilities visited were owned by companies other than Du Pont, and these organizations were very willing to share information. Design and construction engineers also participated in these tours. In some cases, a second visit was made to observe a pulverizer overhaul or some other significant event that offered a learning opportunity.

Vendors offer good training

Most companies supplying equipment for the project have formal training programs available. Cape Fear personnel participated in these programs to the maximum extent possible. Before an order for equipment was placed, the supplier's service arrangements and quality of training were analyzed. The Cape Fear plant had traditionally trained only supervisors in the vendor schools, then used these people to train operators and mechanics on the same subject in-plant. As training needs for the coal conversion were analyzed, it became apparent that this approach would not take advantage of the best training available, so the decision was made to send not only supervisors but also operators and mechanics to training programs for certain equipment.

Training that could be effectively conducted in-plant was held there. This included packaged "power-operator" training, consisting primarily of programmed-instruction courses. Such courses are designed to give operators and mechanics fundamentals of powerhouse operation and maintenance through self-taught, self-paced instruction. These courses, developed by Du Pont personnel, can be used at any powerhouse location.

Many manufacturers have developed video tapes that teach operation and maintenance of their equipment. Several were purchased prior to startup. This training material has the advantage of providing retraining at any time. The video tapes and viewing equipment are kept in the powerhouse operating area, where operators and mechanics are encouraged to view them as needed. Also, as preparations are made for overhaul of a pulverizer, for example, the group to do the work will review appropriate video tapes.

As startup approached, every major system was checked out by the manufacturer's startup engineer. While the engineer was on location, his services were used to do some training, which ranged from four hours to two days, and was usually a combination of hands-on and classroom training.

Supervisors and mechanics participated in the functional testing of instrument panels prior to shipment from the manufacturer's plant. This was a valuable training opportunity for the people who will later be involved in facility checkout and startup. The testing also proves that the panel will do what it was designed to do. If problems are encountered, troubleshooting and correction at the manufacturer's facility are completed under the best conditions.

How a boiler handles refuse-derived fuel

By C Stodolka, Hooker Chemical Co,
and **P J Adams,** Foster Wheeler Ltd

The first industrial boiler designed and built to operate on refuse-derived fuel (RDF) prepared on site is now operating continuously at Hooker Chemical Co, Niagara Falls, NY. Many problems involved in burning this difficult fuel have now been substantially solved.

The primary cause of the problems experienced during startup of the steam plant was the difference between the specified fuel and the actual fuel received from the refuse-preparation plant. Another problem was the high quantity of ash in RDF, which affected the system because of its volume and because of the wear it caused. Large quantities of wire and rags in the fuel presented another potential problem. This might have been worse if an early decision had not been made to pick out household appliances, truck tires, and sofas, before shredding.

The two Hooker steam generators are conventional top-supported, two-drum, baffleless units, fired by spreader stokers with continuous-ash-discharge grates. The front wall of each unit is equipped with two rows of eight feeders each, the lower row consisting of pneumatic distributors for refuse distribution. The upper row consists of mechanical distributors for coal. The units were designed to be fired to full capacity with either coal or RDF or a combination of both. The furnaces are also equipped with oil and gas burners in the rear wall. Some hydrogen may also be burned.

Furnaces are of welded-wall construction, and boiler convection banks consist of 2.5-in.-diameter tubes, swaged top and bottom. The system includes economizers, hot electrostatic precipitators, and regenerative air heaters. Based on worldwide experience in burning municipal refuse, considerable conservatism was specified in the design.

Fuel distribution. While RDF is reasonably homogeneous, there is a tendency for the heavier particles to fall close to the front of the grate, while lighter particles generally burn above the grate. Clinkering was experienced as a result of the poor front-to-back distribution. To solve this, under-distributor air jets were set to their maximum position, and ski jumps were installed in the distributors to loft the fuel towards the rear. Care must be taken that too much fuel does not hit the rear wall.

The fuel-feeding system must be tailored to the fuel, particularly the large quantity of wire and rags. Live-bottom-bin screws are cleaned weekly at Hooker. Chutes between live bottom bins and stoker distributors are being enlarged. Wire is regularly removed from underneath the stoker grate. Rotary valves under the stoker sifting hoppers have been replaced by slide gates.

A grate speed of up to 30 ft/hr has been found necessary to handle the extreme quantity of ash. Grate wear is so heavy that a replacement grate may be needed every year, instead of the expected five-year interval. Ash hoppers and ash-handling system have required considerable labor.

Combined coal/RDF firing has been seriously affected by the large quantity of ash. Since grate speed must be kept high to handle RDF ash, unburned coal is dropped into the ash pit. This problem has been resolved by simply firing the fuels separately, that is, firing RDF until it is exhausted, then properly adjusting for firing coal alone. This is satisfactory because it is desirable to burn all available RDF before firing coal.

Superheater erosion has resulted from the combined effect of sootblower use and the highly erosive ash quantity. The retractable sootblower picks up particles from the furnace arch and blasts adjacent tubes. To solve this, sootblower pressures and blowing frequency have been reduced as much as possible, and sootblower alignment is carefully checked. Special provisions have also been made for warmup and draining of the sootblower system. In addition, openings in the arch tile, designed for draining of ash, have been enlarged, and three shields have been installed.

Corrosion of side-wall and rear-wall furnace tubes has been considerable. While laboratory analysis indicates that the wastage results from chlorine corrosion, it is noted that the major metal loss is in areas where the fuel is blasted against the wall. This problem has been tackled with plasma spray coatings, provisions for admission of boundary air along the affected walls at grate level, and readjustment of the stoker.

While these and other problems presented some difficulties with shakedown, the steam-generating plant is now operating daily, and all goals have been met or surpassed. As of mid-July 1982, the plant has qualified as a cogeneration facility under federal Public Utilities Regulatory Policies Act (Purpa) regulations. It is now desirable and possible to operate the turbine continuously at maximum rating for delivery of power to Niagara Mohawk Power Corp.

SESSION 5: POWER GENERATION AND ELECTRICAL EQUIPMENT PERFORMANCE

Equ'pment for the generation of electrical power and electrical energy-using equipment are presented in this session.

In the first part of the session, the main types of power generating equipment are discussed, together with their performance factors. In the second part, the major industrial users of electrical energy-transformer motors and lighting systems are detailed. Parameters impacting on their performance are given.

Electricity is normally the most expensive energy source for an industrial plant, and savings in energy use can bring major cost benefits.

The discussion on power generation is confined to the production of electricity from the combustion of fossil fuels. No mention is made of power generation from other sources, such as nuclear power. More power is generated from the combustion of fuels than other sources, and so it is appropriate to focus on them rather than on other sources.

POWER GENERATION

Electric power can be generated in two distinctly different types of systems: power-only generation and cogeneration. In a power-only system, fossil fuel is burned to drive a turbine or shaft that is in turn connected to an alternator (or electric generator) to generate electricity only. A cogeneration system, on the other hand, uses the heat of combustion to produce a combination of electric power and process steam. Normally used in industrial applications, the basic function of a cogeneration system is to produce process steam with electrical power representing a by-product. Cogeneration systems are discussed in detail in Session 19 and hence will not be dealt with in this session.

There are several systems used for combustion of fossil fuel for power generation:

- Boiler
- Gas turbine
- Reciprocating engine.

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These systems and associated components are discussed in the following paragraphs.

Boiler Systems

Boilers are used to generate steam at high pressure, which in turn is used to drive a steam turbine, connected via a shaft to an alternator. High-pressure steam increases the overall thermal efficiency of electrical power production.

Water tube boilers are generally preferred to fire tube boilers for large stationary installations because of high pressure requirements (up to and above critical point conditions 374°C, 221 bar). Water tube boilers also convert water to steam more rapidly than fire tube boilers.

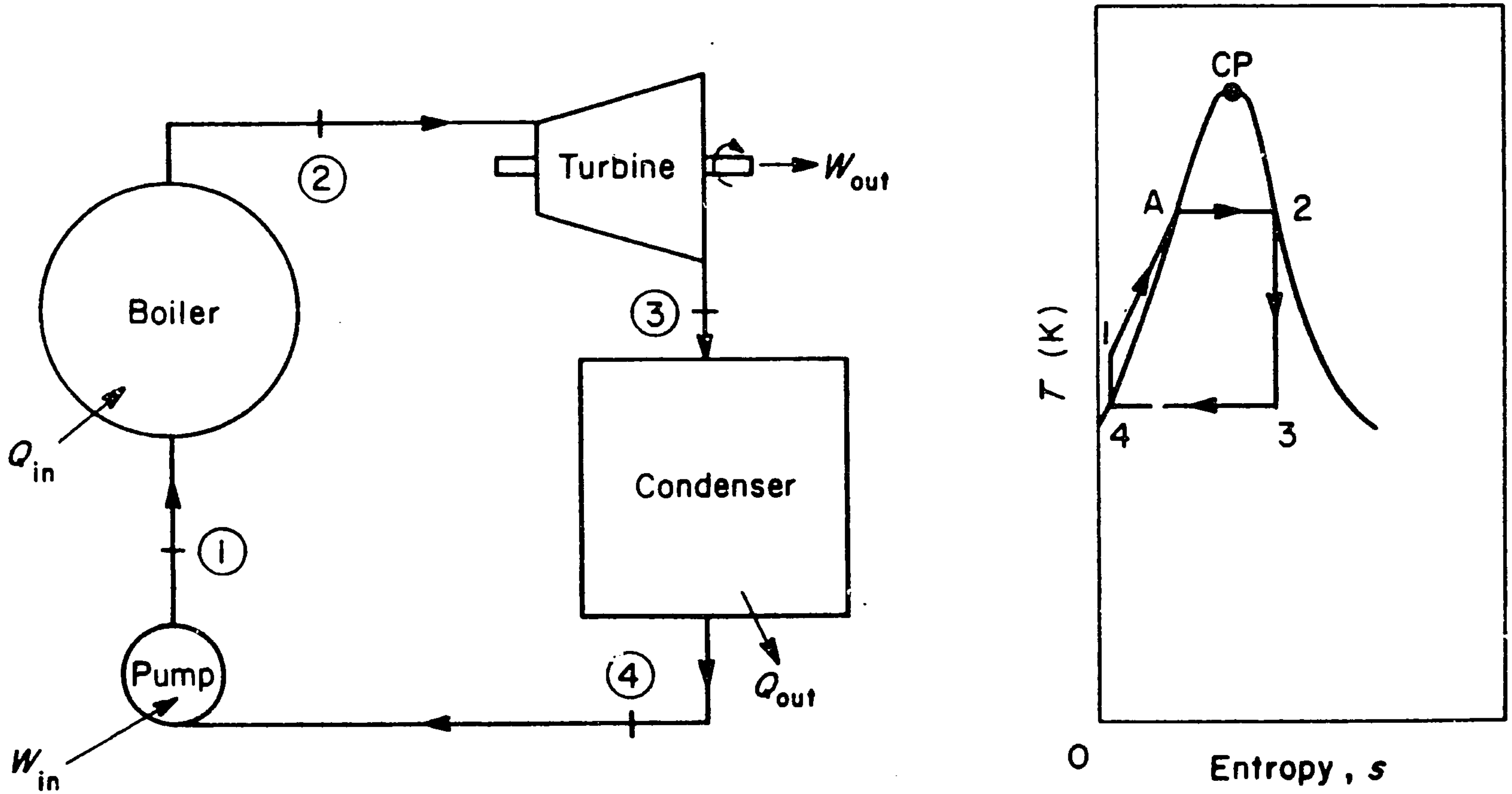
When it passes through the turbine, the steam pressure falls at or below atmospheric pressure. The low-pressure steam is then condensed to water in a condenser. Water is then pumped back into the boiler and the cycle repeated.

Overall plant efficiency is governed by the individual efficiencies of the equipment used, and is therefore a function of the boiler efficiency, turbine mechanical efficiency, and generator/alternator efficiency.

The net effect is to reduce the plant efficiency considerably. Typically, steam generating plants operating using the steam cycle shown in Exhibit 5.1 would have overall plant efficiencies on the order of 25-30 percent for medium and large capacities (e.g., greater than 5 MW) and 15-25 percent for small capacity (100 kW to 5 MW). The reason for the low efficiency is that the cycle thermal efficiency used for power generation is itself limited to less than 40 percent because of the limits imposed by:

- Metallurgical properties of turbine blades and boiler tubes
- Condensing temperature -- 27°C
- Maximum cycle temperature -- 627°C.

Exhibit 5.1



The basic steam cycle

Thermal efficiency can be raised by the following:

- Superheating steam
- Superheating steam and reheating steam
- Superheating steam, reheating steam, and regenerative feedheating.

Superheating steam has two major advantages. First, it significantly increases the steam temperature above that of its saturated conditions, while staying within the limits imposed by the metallurgical materials. It has the second advantage of improving the dryness of the steam. Steam is not completely dry when evaporated from a boiler. Water droplets are entrained in the vapor, causing a condition known as "wet" steam. Superheating will help by evaporating some of the water droplets and effectively drying out the steam.

Reheating involves using two turbines. The steam is expanded through a high-pressure turbine and is then reheated at constant pressure back to its original pressure. The steam is subsequently expanded through a low-pressure turbine down to condenser pressure. Superheaters and reheaters are usually incorporated as integral parts of the boiler plant.

Regenerative feedheating involves "bleeding" steam from one or more positions along the turbine expansions and using this steam to preheat the water in feedheaters before it recycles to the boiler.

Gas Turbine Systems

Gas turbine systems designed for electric power generation fall into two categories, open-cycle and closed-cycle systems. In the open-cycle system, combustion air is compressed in the compressor stage and passed into the combustion section of the gas turbine where it mixes with fuel. Combustion takes place and hot exhaust gases are exhausted through the turbine section. The rotating turbine is connected via a shaft to the alternator that produces the electric power. Even after passing through the turbine, the exhaust gases contain a lot of heat, and it is common to recover the heat via a regenerator or waste gas boiler.

If the exhaust gases are recycled back to the inlet of the gas turbine, the system is a closed-cycle gas turbine. However, the exhaust gases contain excess heat that must be removed before they enter the compressor inlet. This is done using a precooler in the line between the turbine and compressor inlet. The combustion section is replaced by a surface heat exchanger similar in design to a water tube boiler. The air for use in the gas turbine cycle is passed through the tubes and heated by fossil fuel combustion. The air then passes through the turbine section, through a regenerator, before entering the precooler to recommence the cycle. Because air is precooled, its pressure can be increased. By using higher pressure air, the size of the compressor, intercooler, regenerator, and turbine can be reduced. However, the combustion section and the precooler must be increased in size.

Gas turbine system efficiency is affected by:

- Inlet air temperature to compressor
- Turbine inlet temperature
- Pressure at compressor inlet
- Pressure at compressor outlet.

Simple open-cycle gas turbines have operating efficiency between 20-25 percent. With a regenerator, efficiency can be increased to about 32 percent.

Adding an intercooler and using two-stage compression also increases the thermal efficiency to close to 30 percent when compared to the simple open cycle.

The operation of gas turbines is affected to some degree by the ambient air temperature, and they tend to operate less efficiently in summer than in winter, when air is colder and hence more dense.

Gas turbines are normally operated for meeting peak load demands as they can be started and reach full output in relatively short time periods, unlike steam-based power generation systems. However, the efficiency of gas turbine systems is relatively poor, typically 25-30 percent in comparison to 32-35 percent for modern steam-generating systems.

Reciprocating Engines

Reciprocating engines can be used for power generation. The most common reciprocating engine used for power generation is the diesel engine.

Air for combustion is compressed by the action of a piston and becomes heated. Fuel is then injected into the piston chamber and ignites on contact with the air. The combustion process forces the piston down. By connecting a number of pistons via a shaft, the compression and expansion cycles can be used to turn the shaft that is connected to a generator to produce electric power.

The diesel engine design offers a high compression ratio (ratio of maximum and minimum piston cylinder volume) for high efficiency. Combustion air is compressed to about 30 bar for stable ignition to occur (535°C). Compression ratios in excess of 30 bar do **not** increase efficiency very much, and typical pressures are between 30-40 bar. Actual temperatures and pressures used in diesel operations for a given compression ratio depend on engine speed, cylinder size, and other design factors. Smaller, high-speed engines generally have higher compression ratios than large ones.

In practice, the number of pistons and cylinders govern how a diesel engine "breaths" (how air and exhaust gases enter and leave the cylinder). The breathing system itself is not perfect, and the weight of air or air-fuel mixture the cylinder receives is less than it can theoretically hold. Breathing system performance is measured by volumetric efficiency. The volumetric efficiency is the ratio of air drawn in divided by the volume swept by the piston.

Two methods are used for increasing the amount of air intake: supercharging and turbocharging. In supercharging, air is blown into the cylinder using a blower. Turbocharging uses the gas turbine principle. Exhaust gases are passed into a turbine connected via a shaft to a compressor. The exhaust gases thereby compress the inlet air, which in turn sweeps the exhaust gases from the cylinder.

Air compression increases air temperature, which in turn increases heat stresses in the engine. Therefore, it is common to use an intercooler to cool down the compressed air before it enters the cylinder.

Diesel generators generally operate at thermal efficiencies in excess of 30 percent and sometimes above 40 percent. Although there is little change in efficiency with size, large lower-speed diesels tend to be more efficient.

Stationary diesel engines are used predominantly for stand-by power applications, or as direct drives for compressors, pumps, etc. They are also used in utility applications, but predominantly to meet peak load demands.

ELECTRICAL ENERGY-USING EQUIPMENT

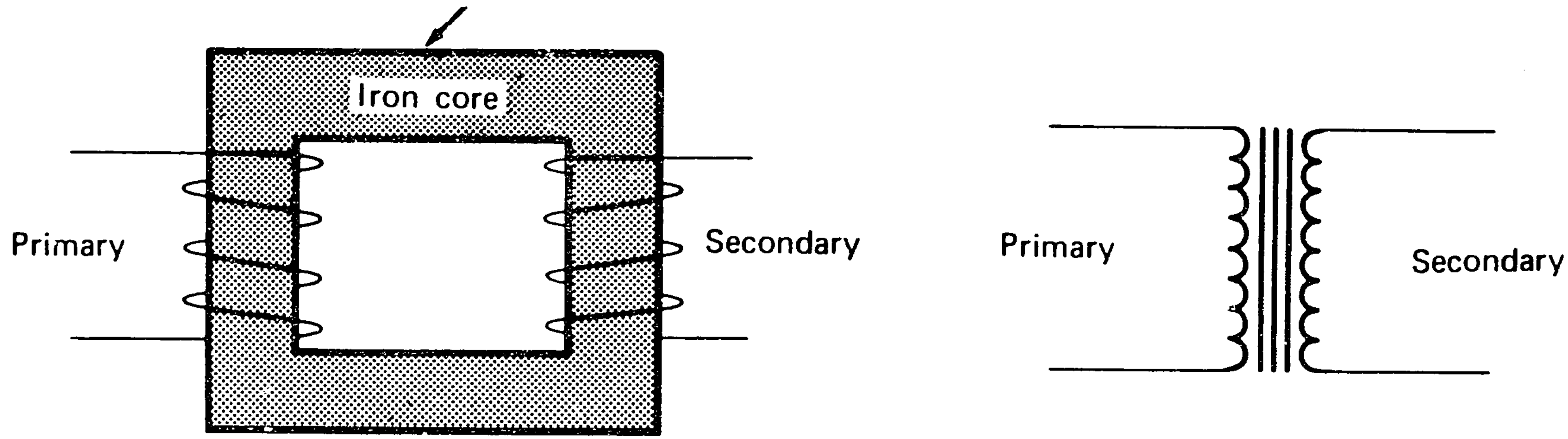
This section deals with three major types of electrical energy-using equipment in industry: transformers, motors, and lighting systems. The most common electrical user is the alternating current (AC) motor, which provides motive power to a variety of equipment.

Transformers

Function

Transformers transfer electrical energy at some value of current and voltage from one circuit to another circuit at some other value of current and voltage. Basically, transformers consist of two or more coils wound around one laminated core (see Exhibit 5.2). In operation, one of the coils (known as the primary circuit) draws power from a power source; the other, or secondary circuit, delivers power to the load. The amount of power transferred from the primary to the secondary is determined by the current flow in the secondary circuit. The current is itself dependent upon the power requirements of the load. Hence, power transfer from the source to the load is regulated by the transformer in response to the load requirements.

Sketch of Transformer and Schematic Symbol



Efficiency

Transformers have no moving parts and require only routine maintenance. They are simple, rugged, and fairly efficient. Their performance is determined by the efficiency of the power transformation, or:

$$\text{Efficiency} = \frac{\text{Power out}}{\text{Power in}} .$$

Losses are usually small for transformers, resulting mainly from heat generated in the coil windings. Transformers are either air-cooled or cooled by insulating oil. Because of their relative high efficiency (0.6-2 percent loss at full load), transformers are not usually tested as part of a plant energy audit. However, they should not be neglected as part of the overall efficiency project.

Motors

AC motors are the most common electrical energy user in plants. For this reason, the paragraphs below will concentrate on AC motors, although many of the comments made can apply to the other types of motors as well.

Function

The AC motor is used to provide motive power to a variety of equipment in industry (e.g., fans, pumps, compressors, conveyors). It is available in a wide range of sizes from fractional to very high horsepower. Similarly, motor duties vary considerably; some motors are required to operate continuously, while others operate intermittently but drive heavy loads.

Because AC motors come in numerous models to meet very diverse applications, it is necessary to consider the following items to choose the proper type of motor:

- Duty
- Power supply -- voltage, phase, frequency, regulation and continuity
- Mechanical arrangement -- motor and shaft position, bearing type
- Speed requirements
- Power requirements
- Torque
- Inertia
- Frequency of starting
- Ventilation requirements.

The above characteristics are often depicted in graphic form (see Exhibit 5.3). These curves can be used to ensure that a motor is suitable for its potential application.

Efficiency

The efficiency of a motor is defined as:

$$\text{Efficiency} = \frac{\text{energy output}}{\text{energy input}}$$

$$\text{or} \qquad = \frac{\text{horsepower} \times 746}{\text{watts input}}$$

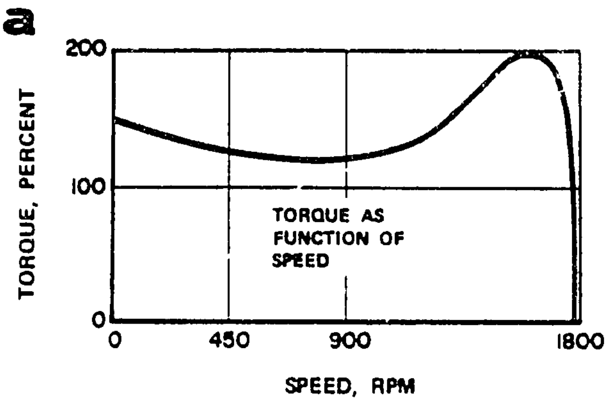
There are several factors that affect motor efficiency, but the most important are:

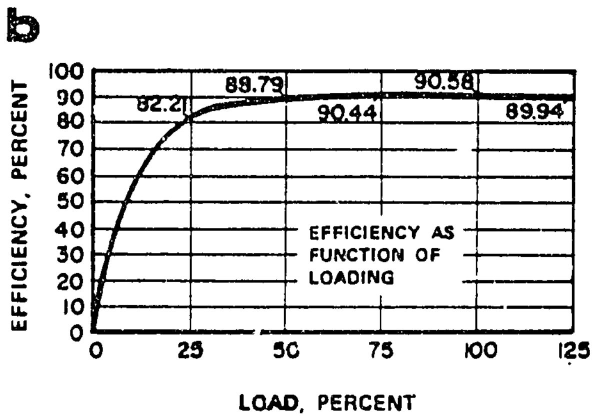
- Sizing the motor to the load
- Type of motor
- Speed.

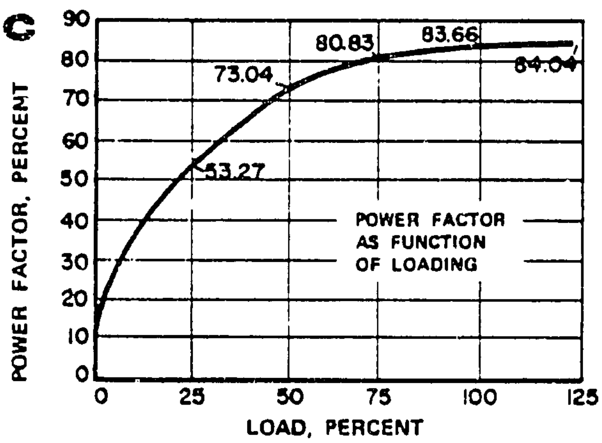
Exhibit 5.4 shows the importance of correct motor sizing: the lower the load, the lower the efficiency. Oversizing will therefore result in efficiency losses. However, modest oversizing may not cause too great a decline in efficiency. While deliberate oversizing is <u>not</u> recommended, it should be borne in mind that an oversized motor is more capable of dealing with momentary overloads without burning out, and it will run cooler. Poor loading, however, can adversely affect power factor.

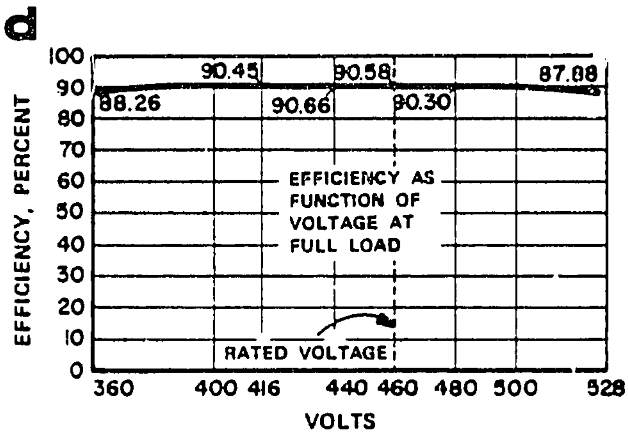
Exhibit 5.3

MOTORS









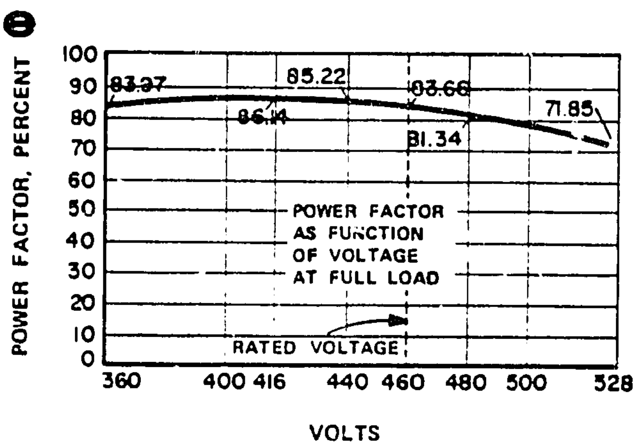
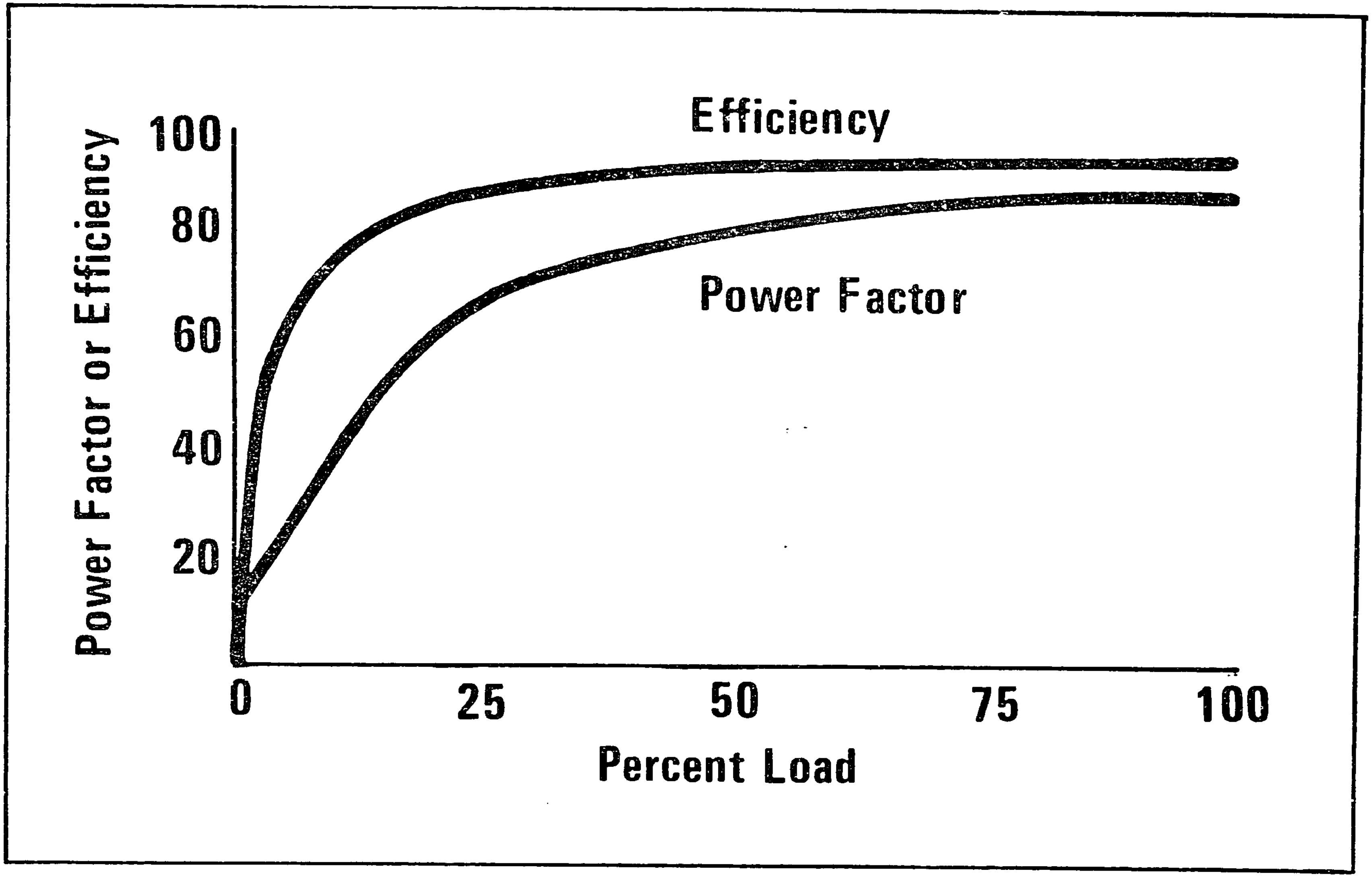


Exhibit 5.4

EFFICIENCY & POWER FACTOR VS. LOAD



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The type of motor selected is important because of the relative differences in efficiency between motors (for example, a capacitor-start/capacitor-run motor is inherently more efficient than a capacitor-start or split-phase motor).

The speed of the motor is of importance because of the relationship between power consumption and speed. Certain types of machinery consume power in proportion to the speed. Others, such as fans, blowers, and centrifugal pumps draw power in proportion to the cube of the speed. For example, if the spped of a fan could be reduced in a ratio of 6 to 5, the savings in power would be 42 percent (see Exhibit 5.5).

Determining motor efficiency is not easy, and specialized equipment is required. However, much information is available from manufacturers. Care must be taken to ensure that motor efficiency is determined by similar methods. For example, the United States, United Kingdom, and Japan have differing standards for testing motor efficiency, so when comparing motors, it is important to check what standard was used (see Exhibit 5.6 for an example).

Lighting

Function

Artificial lighting is provided to permit people to carry out tasks safely and with relative ease where insufficient or no natural lighting is available. Artificial lighting from electrical sources is provided by three types of lamps:

- Incandescent lamps
- Fluorescent lamps
- Discharge lamps.

Each type of lamp has its own operating characteristics that affect its use, and thus its choice:

- Efficiency
- Life

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Exhibit 5.5

POWER SAVINGS BY SPEED REDUCTION FOR OVERSIZED MOTORS

Speed Reduction Ratio = 6 : 5

$(\text{Speed Variation})^3 \propto$ Power Requirements

Power Now	=	6 X 6 X 6	=	216
New Power	=	5 X 5 X 5	=	125
Saving	=			91
% Saving	=	$\frac{91}{216}$	=	42%

Exhibit 5.6

MOTORS

Standard	Full Load Efficiency 7.5 HP	Full Load Efficiency 20 HP
International (IEC 34-2)	82.3%	89.4%
British (BS-269)	82.3	89.4
Japanese (JEC-37)	85.0	90.4
U.S. (IEEE-112, Method B)	80.3	86.9

- Color — both chromaticity and rendition
- Ballast requirements.

Types of lighting sources and their characteristics are discussed below and in Session 20. When artificial lighting is used, it should be remembered that one should not judge the efficiency of the individual lamps only but should judge the overall system efficiency. Too many lighting systems have been designed based on levels of illumination that overlight the work area and also cause glare from lamp fixtures directly or reflect off other surfaces. Hence, lighting systems have to be judged both from the amount of energy consumed as well as from the quality of light produced. An essential element of operating the lighting system is a knowledge of the work or task that is to be performed in the illuminated area. Standards for illumination have been determined by authorities in most countries. However, these standards do not always take into account areas where special lighting requirements for color rendition are required (e.g., textile mills, retail stores).

Efficiency

Judging the efficiency of a lighting system can be difficult because of locations with special needs, but energy conservation opportunities often exist whereby lighting standards can be improved and energy consumption can be reduced. To better understand this situation, a review of the three main sources of electric light are presented.

Incandescent. Incandescent bulbs produce light by passage of an electric current through a very thin wire filament. The filament heats to a point of incandescense, producing light. Incandescent lamps are not as efficient in terms of light output as other sources but have some advantages: they cost less to purchase initially or to replace; they are easily controlled, and do not require ballasts for operation; and the light produced by these bulbs is used by many people as the basis for comparing color renditioning of other sources. The retail trade in particular believes that incandescent lamps provide the most suitable lighting for display and atmospheric conditioning. Normal incandescent bulbs have shorter lives than other sources and lose light output over the life of the bulb. Special tungsten halogen bulbs do have a long life and maintain light output over the life of the bulb.

Fluorescent. A fluorescent lamp is a discharge source that is widely used. Light is produced by an electric arc, causing ultraviolet rays to strike a phosphor coating on the inside of the lamp. The ultraviolet rays are converted into visible light. A ballast is required to regulate the current and to supply the starting voltage necessary to strike the arc if supply voltage is too low. Fluorescent lamps have a higher efficiency and a longer life than regular incandescents. Also, because the tube uses a coating to produce light, the type of coating can be changed in different bulbs to produce changes in chromaticity and color rendition. However, their initial cost is higher than that of incandescent bulbs of similar characteristics.

Discharge. Discharge lamps operate in a similar fashion to fluorescents, using a ballast to strike an arc and produce visible light from a coating. There are two major types: high-intensity discharge and low-pressure sodium. High-intensity discharge lamps use mercury, metal halides, or high-pressure sodium for coatings and produce high efficiency lighting, with good color rendition. Low-pressure sodium lamps give the highest efficiency, but give a monochromatic yellow light that can be unsuitable in some instances. For example, a copper wire and cable plant replaced its fluorescent lighting systems with a system using low-pressure sodium for purposes of energy conservation. However, the plant personnel found that they were unable to see the copper wire in the cabling department as it was wound onto cabling machines. Because this represented a danger to safety, they had to replace the low-pressure sodium in that particular area of the plant. Discharge lamps are more expensive but more efficient than other lighting systems.

Hence, assessing lighting system efficiency is not simple. It must be done by first using a light meter to measure the light provided by the lighting system. In addition, the geometry of the location must be measured, and the use of the space must be considered. A lighting budget for the space can then be determined, and a comparison with standards can determine whether lighting levels can be reduced.

Calculate KVAR and power factor with a programmable calculator

A programmable calculator program that calculates KVAR and power factor without the use of clumsy nomographs and charts

By **FREDERICK J. SEUFERT, PE,**
Principal, Frederick J. Seufert & Associates, Inc., Bahama, N.C.

Are you tired of calculating capacitor KVAR and power factor from clumsy nomographs and charts? Here's a program for the TI 59 programmable calculator with PC-100A printer that makes the whole task quick and easy and provides for the successive iterations necessary in real life.

An engineer can expect increased interest in correcting his overall plant power factor as utilities around the country tighten up their power factor requirements. Probably a majority of the utilities set a 0.85 power factor as the number below which adverse penalties apply. A number of utilities are now increasing this factor to 0.90 or higher. From the utility point of view and from that of their customer base as a whole, this is a good move. It will insure better use of the utilities' transmission facilities. For example, a utility that can increase the average power factor on its transmission lines from 0.80 to 0.90 will, in effect, increase its power transmission capabilities on a given line by 12.5 percent at no cost to itself—the customers will pay the costs!

One of the big utilities in the mid-South, TVA, is expected to increase its power factor requirement from 0.85 to 0.90 in October 1984. The plant engineer will probably get an anxious call from his financial officer inquiring what can be done about the situation when the increase notice from the power company arrives. Some measures taken in an orderly fashion can solve the problem.

The primary cause of poor power factor in an industrial plant is underloaded motors. A perfectly respectable 100 hp motor operating at 90 percent load can be expected to have a power factor of 0.85. The same motor operating at 20 percent load will have a power factor near 0.44. Unlikely? Not at all. There are plenty of 100 hp motors operating in air compressor service that see this typical condition as Example 2 will make clear.

The first thing to be done is to downsize all motors to the correct size taking all factors into account. For the typical application, we recommend sizing the motor at 110 percent of the known load. Assuming a service factor of 1.15, this provides a margin of about 25 percent for overloads and unusual conditions without stressing the motor. It also provides for operating the motor at or near its optimum efficiency point. Generally speaking, a large motor of modern design will have a flat efficiency curve from about 70 percent to 115 percent load, not varying more than 0.1 percent from its expected nominal efficiency of 93.7 percent.

Proper sizing of the motors in a plant can typically be expected to bring the average power factor to about 0.85. Improvement of the power factor to 0.90 or higher will require specific measures.

The easiest method is to add capacitors. The utility companies are generally very careful about power factor on their lines, and, without a doubt, the utility representative will be happy to show you the capacitors on the lines, or you can see them in most substations. They are the square or rectangular cans arranged in banks and connected to the utility lines.

The next questions are how many capacitors are needed, where should they be placed, and how much will they cost? Working through a couple of examples will answer these questions.

Example 1

Let's look at the whole plant problem first. The utility company has measured the demand at 2000 KW and the plant power factor at 0.83. The electric bill is $82,000. The utility has just increased its power factor requirement from 0.85 to 0.90 and proposes to assess an additional adverse power factor charge. It calculates the charge by dividing 0.90 (their requirement) by the actual measurement (0.83) and multiplying the bill by this factor, resulting in a surcharge of 8.4 percent—an actual charge of $6888! The plant had previously been paying a surcharge of $1976 per month, which was burdensome, but nothing had been done about it. The controller wants some action. What can be done, and how much will it cost?

To solve this problem, we use the program shown in Fig. 1. Enter the

Calculate KVAR and power factor

program as shown in the figure. To save the program, you will need to record it on only one side of a magnetic card.

Step	Code	Key	Step	Code	Key
000	76	LBL	063	08	08
001	11	A	064	43	RCL
002	71	SBR	065	04	04
003	19	D'	066	75	-
004	10	E'	067	43	RCL
005	76	LBL	068	08	08
006	19	D'	069	95	=
007	58	FIX	070	42	STO
008	02	02	071	09	09
009	01	1	072	98	ADV
010	34	√x	073	98	ADV
011	91	R/S	074	09	9
012	99	PRT	075	42	STO
013	42	STO	076	00	00
014	01	01	077	01	1
015	04	4	078	42	STO
016	34	√x	079	10	10
017	91	R/S	080	76	LBL
018	99	PRT	081	17	B'
019	42	STO	082	73	RC*
020	02	02	083	10	10
021	22	INV	084	99	PRT
022	39	COS	085	01	1
023	42	STO	086	44	SUM
024	03	03	087	10	10
025	09	9	088	97	DSZ
026	34	√x	089	00	00
027	91	R/S	090	17	B'
028	99	PRT	091	98	ADV
029	42	STO	092	98	ADV
030	06	06	093	58	FIX
031	43	RCL	094	00	00
032	03	03	095	91	R/S
033	30	TAN	096	76	LBL
034	65	×	097	12	B
035	43	RCL	098	71	SBR
036	01	01	099	19	D'
037	95	=	100	53	(
038	42	STO	101	53	(
039	04	04	102	53	(
040	92	RTN	103	43	RCL
041	76	LBL	104	04	04
042	10	E'	105	75	-
043	43	RCL	106	43	RCL
044	01	01	107	06	06
045	55	÷	108	54	)
046	43	RCL	109	55	÷
047	02	02	110	43	RCL
048	95	=	111	01	01
049	42	STO	112	54	)
050	05	05	113	22	INV
051	43	RCL	114	30	TAN
052	06	06	115	54	)
053	22	INV	116	95	=
054	39	COS	117	98	ADV
055	42	STO	118	98	ADV
056	07	07	119	99	PRT
057	30	TAN	120	39	COS
058	65	×	121	99	PRT
059	43	RCL	122	58	FIX
060	01	01	123	00	00
061	95	=	124	91	R/S
062	42	STO			

1 Program listing.

After the program is entered, initiate it by pressing Key A. The display will show 1.00. Then proceed as follows:

- Enter the demand (P): 2000, R/S
- Enter the existing power factor: 0.83, R/S
- Enter the desired power factor: 0.91, R/S

The tape will echo the inputs as shown in Fig. 2. The program will then perform its calculations and print out the following:

- Power in KW: 2000
- Existing power factor: 0.83
- Power factor angle in degrees: 33.90
- Reactive power in KVAR (Q): 1344.01
- KVA: 2409.64
- Desired power factor: 0.91
- New power factor angle in degrees: 24.49
- New reactive power (Q_1): 911.23
- Capacity required in KVAR: 432.78

The program calculates a requirement for 433 KVAR on an overall plant basis. Note that we have entered the desired power factor at 0.91 instead of the utility requirement of 0.90 to provide a small margin of reserve. The solution of 433 KVAR is an odd size. We find that the nearest capacitors available are rated at 450 KVAR. If these capacitors are installed, what will be the effect? This program will provide the answer.

To initiate this part of the program, press Key B. Then do the following (Fig. 3):

- Enter P: 2000, R/S
- Enter the existing power factor: 0.83, R/S
- Enter the available capacitors: 450, R/S

The output will be as follows:

- New phase angle in degrees: 24.08
- New power factor: 0.91

This is a perfectly acceptable answer. Note that the absence of a negative sign in front of the phase angle is an indication that the phase angle is *lagging*, which is desirable.

```
2000.00
   0.83
   0.91
```

2 Output for Example 1 (Key A).

```
2000.00
   0.83
  33.90
1344.01
2409.64
   0.91
  24.49
 911.23
 432.78
```

```
2000.00
   0.83
 450.00

  24.08
   0.91
```

3 Output for Example 1 (Key B).

Where should the capacitors be placed? There are three possible locations: outside on the transmission lines after the meter but before the lines enter the plant, at the central switchgear station inside the plant, or at the individual motors. The first location will require working with the utility. If the loads are constant, it may well be the best location. Outside capacitors may also represent the lowest cost solution.

Location at the central switchgear station inside the plant involves additional switchgear to insure that safety requirements are met. Large capacity capacitors represent a substantial threat to human life if handled carelessly. Also, if the load varies, it will be necessary to switch the capacitors in and out automatically. This is a complex area, and the plant engineer would be well advised to seek the assistance of a consulting engineer.

Location at the individual motor loads is usually preferred. This automatically takes care of the varying load problem because the capacitors are placed on the load side of the contactor and switch on and off with the load. Placement of the capacitors on the load side insures that they are grounded through the motor windings when the motor is shut off. Additionally, capacitors designed for this service usually incorporate resistors to insure bleed-down if inadvertantly disconnected.

Costs of the capacitors vary widely. The following costs are

U19

```
18.00
 0.20
 0.91


18.00
 0.20
78.46
88.18
90.00
 0.91
24.49
 8.20
79.98
```

4 Output for Example 2 (Key A).

```
70.00
 0.61
80.00


 8.88
 0.99
```

5 Output for Example 2 (Key B).

probably typical:

- Outside, pole mounted: $4 per KVAR
- Inside, motor mounted: $10 per KVAR
- Inside, variable, switched: up to $100 per KVAR

In the case just cited, the engineer could probably count on solving the problem with individual motor capacitors for something like $4300 plus installation labor to avoid the adverse power factor charge of $6888.

The solution of this type of problem is straightforward with the program presented in this article. Additionally, the program gives the capability to deal with a varying load, such as an air compressor of the type that loads and unloads in response to the air demand. Example 2 (based on an actual case) will clarify this.

Example 2

An air compressor powered with a 150 hp motor supplies compressed air to a printing plant. When the air pressure falls to 80 psi, the primary valve closes, and the air compressor pumps air until the pressure reaches 90 psi. At this point, the valve opens and the compressor idles.

The input power and the power factor are measured. For the loaded condition:

- The power input is 70 KW.
- The power factor is 0.61.

For the unloaded condition:

- The power input is 18 KW.
- The power factor is 0.20.

The power factors under both loaded and unloaded conditions are unsatisfactory and must be corrected to 0.91 without the possibility of their going negative or leading. What amount of capacitors should be added?

The unloaded condition will be attacked first. Initiate the program by pressing Key A. Then proceed as shown in Fig. 4:

- Enter P in KW: 18, R/S
- Enter existing power factor: 0.20, R/S
- Enter the desired power factor: 0.91, R/S

The output will be as follows:

- Power in KW: 18
- Existing power factor: 0.20
- Power factor angle in degrees: 78.46
- Reactive power factor in KVAR (Q): 88.18
- KVA: 90.00
- Desired power factor: 0.91
- New power factor angle in degrees: 24.49
- New reactive power (Q_1): 8.20
- Capacity required in KVAR: 79.98

An 80 KVAR capacitor is available, but a second question must be answered. What effect will the 80 KVAR capacitor have on the loaded power factor?

Initiate this part of the program by pressing Key B. Then proceed as shown in Fig. 5:

- Enter loaded P in KW: 70, R/S
- Enter existing power factor: 0.61, R/S
- Enter available capacitors: 80, R/S

The output is as follows:

- New phase angle in degrees: 8.88
- New power factor: 0.99

The addition of the available capacitor will correct the unloaded power factor to 0.91 and will correct the loaded power factor to 0.99, both of which are acceptable numbers.

There is a tendency in industrial plants to think that if a little is good, more has got to be better. That kind of thinking accounts for so many motors being oversized for their applications. However, that kind of thinking doesn't work with capacitors. Too large a capacitor will overcorrect the problem resulting in a poor power factor on the negative side.

To illustrate that, suppose that in the above example that instead of the correct 80 KVAR, the only capacitor available was a 120 KVAR unit and it was installed.

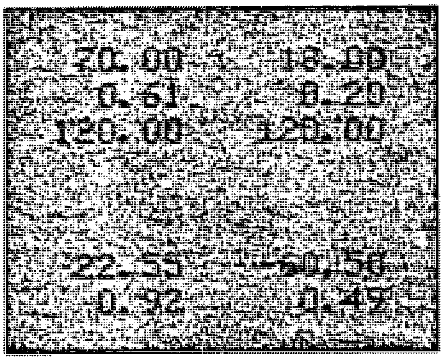
To see the results, initiate the program by pressing Key B. Enter the parameters as shown in Fig. 6:

- Enter P in KW: 70, R/S
- Enter existing power factor: 0.61, R/S
- Enter available capacitors: 120, R/S

The output is as follows:

- New phase angle in degrees: − 22.55
- New power factor: 0.92

We note that the power factor is close to the desired 0.91, but the



6 Output for Example 2 solution check.

negative sign in front the the new phase angle indicates that it is leading!

We then enter the data for the unloaded condition:

- Enter P in KW: 18.00, R/S
- Enter existing power factor: 0.20, R/S
- Enter available capacitors: 120, R/S

The output is:

- New phase angle: − 60.50
- New power factor: 0.49

The power factor is now 0.49 leading! This illustrates the necessity for careful calculation of capacitor size. If it is necessary to use an available size rather than the correct size, it is wise to recheck the calculations. Ω

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SESSION 6: INDUSTRIAL ENERGY MANAGEMENT

INTRODUCTION

As a consequence of the more than tenfold increase in petroleum prices in the 1970s, most countries, including developing countries, have initiated policies and programs aimed at increasing domestic production of petroleum and alternative sources of energy. In most developing countries, initial efforts to reduce the cost of imported energy have focused principally on the energy supply side, and except for attempts to increase energy prices and the temporary rationing of energy supplies, relatively little has been done on the energy demand management side. However, many industrial countries have accomplished significant savings through energy demand management. In most developing countries, the opportunities to improve the energy situation by more efficient utilization of energy are substantial and are normally more economically attractive than increasing supplies. More efficient energy consumption is often also the fastest way to achieve improvements in the energy balance of a country. Policies aimed at increasing domestic energy supply normally take several years to yield significant results, whereas energy conservation/demand measures, particularly in industry, which is the single largest consumer of commercial energy in most developing countries, can produce immediate results. Therefore, **appropriate management of energy consumption in industry should be a critical element of an overall national energy program.**

CONCEPTS

Energy conservation is defined as energy demand management activities that aim at increasing the efficiency of use.* The efficiency of use has two different, although not separate, components: technical efficiency and economic energy efficiency.

The first component, **technical efficiency**, is often measured by the first law of thermodynamics, which provides a quantitative estimate of the ratio of useful energy output (of

*This concept is not related to the concept used in physics of "conservation of energy," which states that energy cannot be created or destroyed, although it can be changed from one form to another.

a given process or piece of equipment) to energy input. For example, the first law of thermodynamics indicates that the technical energy efficiency of most boilers ranges between 70 and 85 percent. However, the first law is of limited interest, as it generally provides high technical efficiencies that do not indicate the real potential for improvement. The second law of thermodynamics, which considers the quality of energy, is often preferred when value judgments in energy efficiency must be made. Efficiency under the second law is defined as the ratio of the **least** amount of energy necessary to achieve a particular objective to the amount of energy actually used to attain this objective. Using this law, energy efficiencies of most industrial processes range between a few percent (e.g., grinding) to 45 percent (cogeneration of heat and electricity), as opposed to 40-90 percent using the definition of efficiency under the first law.

Because second-law efficiency computation is a rather complex exercise that is seldom required for the typical industrial energy user,* energy efficiency will be considered as technical efficiency according to the first law.

The second component, **economic energy efficiency**, is not a well-defined concept in absolute terms. Rather, one often refers to relative economic energy efficiency when an energy-related decision such as switching fuel in a sector results in providing the same energy service (e.g., producing steam at given temperature and pressure conditions) at a lower cost. The practical implications of this definition are not simple, as most energy-related decisions involve other production factors such as labor, raw materials, or capital. Rather, economic efficiency must be viewed in the global context of investment efficiency and optimal resource allocation. Consequently, economic energy efficiency is better measured using conventional investment theory under adequate pricing assumptions. Similarly, the macro measurement of a nation or a sector's energy efficiency, often measured as the ratio of total or commercial energy used to GDP, is of limited value in international comparisons because it fails to point out the specificities of the nations or the sectors.

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*Second-law computations are routine in engineering firms that design new processes and equipment.

Energy savings are the measure of increased energy efficiency, either in technical terms (e.g., toe saved annually in a given industry or operation) or economic terms (cost savings at the enterprise level or the national level). In this session, energy savings will be measured in technical terms, or physical quantities.

The **energy conservation potential** for a given activity (industry, process, or plant) over a given period can be defined as the maximum amount of energy -- computed either at the primary energy or end-use level -- that could be saved using specific technologies under specific economic conditions. In the case of LDCs, these technologies are generally well known, and have been extensively demonstrated and used in industrialized countries. In most cases, the economic conditions require short paybacks (i.e., less than 5 years). Therefore, in estimating the potential, it is necessary to identify all options that meet the selected technological and economic criteria.

For example, cement manufacturing requires between 0.1 and 0.2 toe/ton in LDCs; in Sri Lanka, for example, specific energy consumption is about 0.17 toe/ton, compared with the best world performance of 0.1 toe/ton. Sri Lanka would set itself an ambitious goal if it were to strive for an energy consumption level of 0.12 toe/ton over the next 5 to 10 years.

APPROACHES

There are two approaches to estimating energy conservation potential. The **micro approach** (which can also be called the "bottom-up" approach) consists of estimating at the plant level cumulative energy savings resulting from the implementation of all possible conservation measures corresponding to the selected technological and economic conditions mentioned above. The other approach, or **macro approach**, uses a baseline ratio of energy to economy indicator (e.g., toe/thousand dollars of GDP) and projects it into the future according to recent past trends. By comparing this trend (for example, an energy/GDP elasticity of 1.1) to other countries or any other reference, it is possible to set a macro goal (e.g., to reach an energy/GDP elasticity of 0.8 in 10 years).

While the macro approach has the advantage of being easy to implement, its value is highly questionable, as it is difficult to take into account the country- or the sector-specific characteristics (e.g., industry mix, equipment age). The micro approach provides more useful results but requires a larger amount of resources in time and manpower to implement. For example, a representative number of plant audits must be conducted to provide basic data. Because of these constraints, a rough macro approach may be preferred to launch a program, and the potential estimate may be refined later by using the micro approach. Once the approach has been selected and the conservation potential estimated, one can attempt to project how much can be saved under specific conditions.

Projected savings are that part of the potential that can be reasonably achieved. The full realization of the energy conservation potential is prevented by social, institutional, and financial factors. In many industries in LDCs, the energy conservation potential exceeds 50 percent of the current energy consumption (e.g., textile finishing, bricks), while projected savings range between 10 and 15 percent over a 5-year period and between 25 and 30 percent, at best, over a 10-year period.

CONSERVATION AND DIVERSIFICATION

LDCs can reduce energy costs in industry in two generic ways:

- **Through conservation.** Energy conservation is an energy demand management function that aims at reducing the quantity of energy currently used. Such reduction can be achieved at low cost by modifying operating practices or at higher cost by modifying the equipment and the process. All actions belonging to this group result in an actual reduction of energy consumption at the national level.
- **Through fuel diversification,** also called fuel switching, which entails the conversion of energy-using equipment from one fuel to another form of energy (e.g., coal, electricity). Switching to a cheaper fuel, such as coal or noncommercial fuel (e.g., bagasse, wood residues), does not generally

reduce the quantity of energy used.* It does, however, improve the national energy situation by displacing higher value fuels (oil or gas).

CATEGORY OF ENERGY MANAGEMENT MEASURES

Depending on the level of effort required, energy conservation measures are often grouped into three categories:

1. **No-cost/low-cost measures,** often called "housekeeping" measures, which can be implemented very quickly and easily and at very small expense (e.g., shutting down equipment when not required, reducing excess air in boilers).
2. **Minor capital investments,** which require only limited expenditures, have paybacks of less than 2 years, and can be implemented within a few months (e.g., installing simple heat exchangers, replacing burners).
3. **Major modifications,** which require relatively large capital expenditures, have longer paybacks, and require detailed feasibility studies prior to implementation (e.g., boiler replacement, steam system rehabilitation).

ENERGY SAVINGS POTENTIAL IN INDUSTRY

This session attempts to provide quantitative estimates of current industrial energy consumption patterns and savings potential in LDCs. The savings potential (or energy conservation potential) is defined here as the maximum practical amount of primary energy that could be saved using well-known technologies and practices and under specific economic conditions (see above). Technologies and practices considered here are those that are applicable to LDCs.** Economic conditions have been arbitrarily limited

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*Coal and waste fuel combustion is less efficient than oil or gas. Consequently, more input energy is required for a given end use.

**Advanced, not yet proven technologies, such as dry forming process in the pulp and paper industry or direct reduction using coal as a fuel in the steel industry, are not included.

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to a maximum simple payback -- that is, the number of years of energy savings that equal total modification cost -- of less than 5 years.

Under these conditions, the key factors that influence the magnitude of the savings potential are: (1) the amount of energy used in the sector; (2) the industry mix; (3) the processes used in each industry; (4) the level of energy use efficiency in each process; and (5) the type of fuel used. Precise estimation of the potential is not possible, owing to severe data limitations in most LDCs.

Amount of Energy Used in Industry

Total 1980 commercial primary energy consumption in LDCs is estimated at approximately 1,350 million toe (mtoe).* The industrial sector of all LDCs combined used an estimated 600 mtoe, or approximately 45 percent of the world total, and represents the major energy-consuming sector. The share of industry in total commercial energy consumption varies from country to country, owing to a number of factors, including the relative size of the industrial sector compared with the other sectors of the economy (transportation, residential, agriculture, services) and the energy intensity of each sector of the country in question. In most industrialized countries the share of industry in energy consumption is generally in line with its share of GDP, whereas the pattern is significantly more varied in LDCs. In a number of low-income LDCs, industry's share of energy consumption far exceeds its share of GDP, reflecting not only the high energy intensity of these countries' industries, but also the lower income levels and milder climates (which reduce the use of commercial energy in households), and the proportionately low energy intensity of the agricultural or transportation sectors (e.g., China, India). In energy-rich countries, however, the opposite is true, as the share of total industry in national GDP exceeds its share of energy consumption (e.g., Indonesia, Mexico, Nigeria). If manufacturing only is considered, the relative patterns are more in line with each other (see Exhibit 6.1).

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*World Bank, The Energy Transition in Developing Countries, August 1983, page 5.

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Exhibit 6.1

Comparative Share of Industry in Total Energy Used and GDP in Selected LDCs (1981)

Country	Percent of primary energy used in industry		Percent of GDP[1] generated by industry	
	Commercial only	Total, including noncommercial	Manufacturing only	Total industry
Bangladesh	42.5	N/A	8	14
Bolivia	18.0	16.9	14	27
Brazil	51.6	40.7	22	37
China	69.2	50.9	N/A	46
Dominican Republic	28.2	29.1	15	27
India	53.8	N/A	18	26
Indonesia	15.6	N/A	12	42
Korea, Republic of	50.3	47.6	28	39
Mexico	21.8	19.4	22	37
Morocco	36.3	2[illegible].6	18	34
Nicaragua	25.6	16.4	26	33
Nigeria	24.6	N/A	6	37
Peru	22.5	19.1	25	41
Senegal	12.5	13.1	25	37
Sri Lanka	19.9	22.4	16	28
Sudan	16.1	4.1	6	14
Turkey	45.9	36.0	23	32
Uganda	11.4	4.4	4	4
Uruguay	34.8	31.5	26	33
Zimbabwe	41.4	30.0	27	37

[1] From World Bank Development Report, 1983, p. 153.

Industry Mix, Process, and Energy Efficiency

The type of industries predominating in a country has an important impact on the over-all energy intensity of the industrial sector of that country. Some industries consume large amounts of energy per ton of product, therefore increasing the energy intensity of the industrial sector. For example, the production of one ton of ammonia from natural gas or naphtha requires about 1 ton of oil equivalent (toe) as feedstock and fuel; aluminum can require up to 5.4 toe per ton. In contrast, construction materials generally consume less than 0.2 toe per ton of product, and electrical and mechanical equipment manufacturing requires less than 0.1 toe per ton. In some industries (e.g., cement), where energy consumption per ton of product is low, production volume is high, the total amount of energy consumed by the industry can be large, and energy can represent a substantial portion of the total cost of production. Petroleum refineries are another good example: they consume significant amounts of energy, because the refineries themselves consume as fuel about 5 to 9 percent of the total crude processed by them. These industries provide significant opportunities for energy savings.

Energy consumption per unit of output (specific energy consumption) varies widely not only with the type of industry, but also with the process used. For example, modern and efficient steam reforming of natural gas for the production of one ton of ammonia requires 0.7 toe, whereas the older steam reforming processes require approximately 1.2 toe. Similarly, efficient new dry processes for cement manufacture require less than 0.08 toe per ton of cement, while most older wet processes require approximately 0.20 toe per ton. Other factors affecting the energy intensity of industry in a country include the age of the plants (owing to wear and tear, plant efficiency declines with age), the climatic conditions (e.g., in Korea, manufacturing during the winter months consumes significantly more energy than in tropical countries, owing to space heating requirements), and the general operating practices and skills of the plant operators (maintenance and down-time losses). Ranges of typical specific energy consumption in LDCs are provided in Exhibit 6.2.

Exhibit 6.2

Specific Consumption Levels in Selected Energy-Intensive Industries in LDCs

Industry	**Process**	**Specific energy consumption[1] (10^{-3} toe/ton, 1982)**
Steel	Raw steel	450-1,400
	Metal finishing	300-400
Aluminum	Hall-Heroult smelting	4,500-5,400
Petroleum	Refining	35-100
Fertilizers	Ammonia	800-1,100
Glass	Flat and containers	250-600
Construction materials	Bricks	90-200
Cement	Dry process	80-160
	Wet process	130-210
Pulp and paper	Integrated chemical	250-950
Food	Raw cane sugar	0[2]-850
	Cane sugar refining	0[2]-195
	Edible oil	80-335
Textile	Finishing	950-2,500

[1]Total commercial energy (fuel + electricity).
[2]In cases where only bagasse is used.

SOURCE: Hagler, Bailly & Company and World Bank estimates.

Fuel Used

The type of fuel used in industry affects the savings potential for two reasons. First, the efficiency of utilization varies with the type of energy used. Coal is generally less efficient to burn than oil and gas,* and electricity (accounted in primary energy) is less efficient than direct fuel use for thermal operations, especially when it is generated from fossil fuels. Second, countries using primarily oil and gas (e.g., Peru, Argentina) have a great potential for switching to cheaper and more reliable sources of energy, such as coal. However, with the exception of such countries as China and India, which consume primarily coal as industrial fuel (74 percent and 70 percent, respectively), most LDCs meet the energy requirements of their industries predominantly with petroleum products (fuel oil, naphtha, and gas oil).

The fuel mix used depends on economic and technical factors. Economic factors include the relative value of each form of energy and the capital cost of the required equipment, which is significantly cheaper for oil or gas than for coal or other fuels. Technical factors also influence the choice of fuel. For instance, oil or gas is required to manufacture petrochemicals. Some industries, such as glassmaking, consume oil and gas almost exclusively because of the process requirements for clean burning and high temperatures (1,500°C). Other industries, such as cement and steel, can use almost any fuel, depending on its costs and availability. Noncommercial fuels also play an important role in some industries in LDCs. Bagasse is a major fuel source for alcohol and cane sugar manufacturing, and wood residues and black liquor are extensively used in the pulp and paper industry.

Energy Saving Potential by Industry

While there are up to 250 major industrial products consuming significant amounts of energy, a few of them consume most of the total energy used in the industry sector. Major energy-intensive industrial products in LDCs are:

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*Except in large high-pressure boilers.

- Steel
- Cement
- Fertilizers
- Sugar
- Pulp and paper
- Glass
- Aluminum
- Bricks
- Finished textiles.

Petroleum refining, which generally is not considered part of manufacturing, also consumes an amount of primary energy comparable to these processes.

As shown in Exhibit 6.3, a substantial fraction of the world production of these products occurs in LDCs. For example, almost 90 percent of total world cane sugar production and 37 percent of total world cement production occur in LDCs. Using the average energy efficiency ratios of Exhibit 6.2, total commercial energy consumption in 1980 for all LDCs has been estimated. The results indicate that steel is by far the major energy-using product in LDCs, with a total of 79-89 mtoe. Next is cement, with 42-57 mtoe, and petroleum refining (which does not belong to the traditional manufacturing sector, but is shown here because of the similarity of energy conservation with other industrial activities), with 40-45 mtoe. The pulp and paper industry consumed an estimated 21-31.6 mtoe, while all other energy-intensive products or processes used less than 25 mtoe in 1980. Other energy-intensive processes not shown on Exhibit 6.3 include primarily chemical intermediary products (e.g., ethylene), metallurgy (e.g., foundries and nonferrous metals other than aluminum), and some food processes.

An analysis of the candidate conservation measures for each of these industries shows that the savings potential is substantial in all industries, although conservation opportunities -- and thus the savings potential -- tend to be industry-specific. A summary of the findings is provided in Exhibit 6.4, where the conservation measures have been consolidated into two groups:

- Short-term measures requiring small investments and consisting mostly of combustion efficiency improvements, insulation, steam system

Exhibit 6.3

Primary Energy Consumption in Selected Energy-Intensive Industrial Processes, All LDCs, 1980

Industry	Product/process	Estimated production (million tons)[a] World	LDCs	Percent	Estimated commercial energy consumption (million toe)[b]
Iron & steel	Raw & finished steel	713.0	100.7	13.9	79.0-89.0
Petroleum	Refining	2,920.5	691.8	23.7	40.0-45.0
Cement	All processes	867.7	319.4	36.8	42.0-57.0
Chemicals	Ammonia	71.3	15.4	21.6	15.5-18.5
Food	Cane sugar refining	55.6	48.0	86.3	14.5-24.0
Pulp & paper	All grades	166.5	21.1	12.7	21.0-31.6
Construction materials	Glass	99.3	38.7	39.0	13.5-19.2
Electrometallurgy	Aluminum (from alumina)	16.1	2.4	14.9	11.0-12.0
Construction materials	Bricks	97.4	22.8	23.4	2.5-3.5
Textiles	Finishing	18.9	3.2	40.0	3.8-5.7
Total					**242.8-305.5**

[a]All production figures based on latest validated international statistics (1980), including UN and World Bank's commodity and export divisions.

[b]Commercial energy consumption by product has been estimated using specific energy consumption by unit of output within range provided in Exhibit 6.2.

SOURCE: Hagler, Bailly & Company.

Exhibit 6.4

Potential Energy Savings and Typical Energy-Saving Measures in Selected Energy-Intensive Industries in LDCs

Industry	Process	Potential savings rate (percent) Group A[1]	Potential savings rate (percent) Group B[2]	Examples of major energy-saving measures Group A[1]	Examples of major energy-saving measures Group B[2]
Steel	Raw steel metal finishing	5-7	5-13	Combustion controls, insulation, iron ore pellets	Waste heat recovery, replace inefficient equipment
Aluminum	Hall-Heroult smelting	2-4	10-15	Combustion controls in remelting furnaces, insulation, power factor improvement	Install process controls, increase waste heat recovery and aluminum recycling
Petroleum	Refining	7-12	15-25	Combustion controls, increase steam condensate return	Waste heat recovery, replace inefficient equipment
Fertilizers	Ammonia	2-5	20-25	Insulate primary reformer, various housekeeping measures	Waste heat recovery in reformer, hydrogen and CO recovery, replacement of compressors
Glass	Flat and containers	10-12	15-20	Combustion controls, insulation	Install efficient recuperators, waste heat boilers, increase boosting
Construction materials	Bricks	10-15	15-20	Flue gas recirculation, combustion controls, kiln	Stack gas recuperation, kiln rebuilding
Cement	Dry and wet	10-20	10-30	Process optimization such as improved combustion, insulation, etc.	Install high-efficiency heat exchanger systems, process controls, convert from wet to dry process
Pulp and paper	Integrated chemical Other	12-14 10-15	14-16 10-15	Boiler improvements, steam system and insulation reconditioning	Increase use of waste fuels, black liquor, increase cogeneration, waste heat recovery from dryers
Food	Raw cane sugar Cane sugar refining Edible oil	16-18 16-18 8-10	Up to 85 15-30 12-15	Improve boiler combustion efficiency, steam systems and insulation, and evaporator management	Increase use of waste fuels (e.g., bagasse), waste heat recovery, add up effects on evaporators
Textile	Finishing	12-15	15-17	Improve boiler combustion efficiency and steam distribution, increase return	Install waste heat recovery devices, replace old, inefficient boilers, improved water and liquor systems
Other	Metal works, mining, chemical products, wood products	5-10	10-15	Combustion improvement, insulation, operation scheduling, maintenance	Waste heat recovery, replace energy-inefficient equipment, lower temperature, power factor correction

[1]Group A: short-term measures (i.e., housekeeping and minor modifications).
[2]Group B: medium-term measures (i.e., retrofitting and process modifications).

SOURCE: Hagler, Bailly & Company.

efficiency improvements, and other housekeeping measures, including better energy management, measurement, and control (**Group A**)

- Medium-term measures requiring larger investments in retrofits of existing plants and additions to facilities, including waste heat recovery, combined heat and power generation, increased use of waste fuels, simple process controls, some process modifications, and replacement of inefficient equipment (**Group B**).

Based on detailed energy conservation reports prepared by the World Bank and surveys of LDCs' industrial energy conservation programs, it appears that the potential for savings varies greatly by industry. It is estimated that only 2 to 7 percent of the primary energy used in the primary metals industry (e.g., aluminum, steel) can be saved by low-cost measures (**Group A**), whereas up to 10-18 percent would be saved by the same type of measures in processes using essentially low-temperature heat (e.g., in the form of steam). Such processes include pulp and paper, food, and textile products (see Exhibit 6.4).

Similarly, the potential for energy savings by implementing more capital-intensive measures (**Group B**) is estimated to vary from 10-15 percent in metal-related industries to 15-25 percent in industries such as fertilizers, cement, and sugar, where waste heat recovery and use of waste fuels offer considerable savings potential in LDCs (see Exhibit 6.4).

It is estimated that as a group, the LDCs could save approximately 35 to 66 mtoe per year through short-term measures (Group A), and an additional 59 to 111 mtoe per year through medium-term measures (Group B). In percentage terms, these figures correspond to savings of 6 to 10 percent and 10 to 18 percent of total industrial energy consumption, respectively. The largest energy conservation potential lies in steel, petroleum refining, cement, and chemical industries (see Exhibit 6.5).

NATIONAL ENERGY EFFICIENCY IMPROVEMENT PROGRAMS

Despite the generally high economic attractiveness, at least from a national standpoint, of the energy conservation potential discussed earlier, actual energy savings may not

Exhibit 6.5

Potential Cumulative Energy Savings and Investment Required in Selected Energy-Intensive Industries in LDCs

Industry	Product/process	Estimated commercial energy consumption[1] (million toe)	Potential energy savings[2] (million toe/year, rounded)			Typical payback[3] (years)	
			A	B	Total	A	B
Iron and steel	Raw and finished steel	79.0-89.0	5.0-7.0	5.0-13.0	10.0-20.0	1.0-1.5	4.0-5.0
Petroleum	Refining	40.0-45.0	3.0-5.0	6.0-11.0	9.0-16.0	1.0	2.0-2.5
Cement	All processes	42.0-57.0	4.0-7.0	6.0-14.0	10.0-21.0	1.0-1.5	3.5-4.0
Chemicals	Ammonia	15.5-18.5	0.5-1.0	3.0-5.0	3.5-6.0	1.0	2.0-3.0
Food	Cane sugar	14.5-24.0	2.0-4.0	2.0-7.0	4.0-11.0	1.0	3.0-3.5
Pulp and paper	All grades	21.0-31.6	2.0-5.0	2.0-5.0	4.0-10.0	1.5-2.0	2.5-3.0
Construction materials	Glass	13.5-19.2	1.0-2.0	1.0-4.0	2.0-6.0	1.0-1.5	2.0-3.5
Electrometallurgy	Aluminum (from alumina)	11.0-12.0	0.0-1.0	1.0-2.0	1.0-3.0	1.0-1.5	2.0-3.0
Construction materials	Bricks	2.5-3.5	0.5-1.0	0.5-1.0	1.0-2.0	1.0-1.5	2.0-3.5
Textiles	Finishing	3.8-5.7	0.5-1.0	0.5-1.0	1.0-2.0	1.0-1.5	2.5-3.5
Total 10 products		**242.8-305.5**	**18.5-34.0**	**27.0-63.0**	**45.5-97.0**	**1.0-1.5**	**3.0-4.0**
Other products (estimated)		322.7-323.5	16.0-32.0	32.0-48.0	48.0-80.0	1.0-1.5	2.5-3.5
Total all products, all LDCs		**565.5-679.0[4]**	**34.5-66.0**	**59.0-111.0**	**93.5-177.0**	**1.0-1.5**	**3.0-3.5**

NOTE: A = short-term, low-cost measures; B = medium-term, moderate-cost measures.

[1] From Exhibit 6.3.
[2] Using savings rate from Exhibit 6.4.
[3] Based on World Bank reports and review of industrial energy conservation programs and projects in various industries and LDCs.
[4] Range of estimates depends on assumptions made about total primary energy consumption and share of industry.

SOURCE: Hagler, Bailly & Company.

materialize to the full extent desirable. This failure to achieve the full potential energy savings stems from a number of technical, financial, economic, and institutional barriers to energy conservation that are often encountered in LDCs. Major examples of such barriers are presented in Exhibit 6.6.

Main Elements of Industrial Energy Savings Programs

To surmount these barriers and capture most of the potential for energy savings, an integrated energy savings program must be designed and implemented at the national level. Key elements of such programs include appropriate measures for (a) energy pricing, (b) technical assistance, (c) financial assistance, and (d) institutional and regulatory support.

Energy Pricing

To provide enterprises with adequate incentives for improving their energy efficiency through both conservation and fuel conversion measures, appropriate industrial energy pricing policies must address both the absolute and relative price levels of the various energy sources commonly used by industry (fuel oil, gas, coal, power) and, where relevant, a rate structure (electricity and natural gas rate schedules). Although the pricing strategy will depend on country-specific parameters, there is ample evidence to suggest that domestic prices for industrial energy need to be at least equal to international prices to provide adequate incentives for energy conservation at prevailing international prices for equipment. Rate structures for power or gas are also important in that respect. For example, declining block-rate structures may provide disincentives for energy conservation. Some countries, such as China and Romania, use quota systems for key energy products, with consumption above the quota carrying a substantially higher price. In any case, it is of the utmost importance that the government's energy pricing policy be announced in clear terms.

Experience from a number of countries suggests, however, that **adequate energy pricing is a necessary — but generally not sufficient — condition for an efficient energy savings program.** Energy pricing needs to be examined within the context of the overall pricing

Exhibit 6.6

Common Barriers to Industrial Energy Conservation

Technical barriers

- Lack of suitable equipment

Economic barriers

- Domestic energy prices below international levels
- Cost plus price control system for manufactured products
- Energy costs only a small percentage of production costs in some industries

Financial barriers

- Limited capital availability
- High interest rates
- Lack of simple, accessible medium-term financing for energy-saving equipment changes

Institutional barriers

- Inadequate decision-making structure
- Unfavorable legislation and regulations
- Other national and industrial priorities
- Lack of information
- Lack of energy auditing capabilities
- Lack of energy management expertise in plants

SOURCE: Hagler, Bailly & Company.

policy for industry. In countries with a cost plus price control system for manufactured products, there is often no real incentive to save energy. In addition, a policy of high or increasing energy prices will have its full effect only to the extent that most enterprises are adequately aware of and informed about the various energy-saving measures that are technically and economically feasible. Finally, energy costs account for varying shares of total production costs, depending on the industry concerned (see Exhibit 6.7).

In industries such as metallurgy, textiles, and food processing, where energy costs are proportionally modest, enterprises might give higher priority to investments designed to improve their productivity or competitiveness through means other than energy conservation. It is important to design an integrated energy conservation program that includes an array of nonpricing measures and programs. The primary nonpricing measures and programs are discussed below.

Technical Assistance

Technical assistance primarily involves promotion, training, and plant auditing.

Promotion and information campaigns help create an awareness on the part of industrial managers, employees, and the public in general of the benefits of energy savings. The campaigns include brochures, pamphlets, general or industry-specific seminars, and energy savings contests. Training programs in energy conservation or auditing can be addressed to several different groups, such as energy auditors, energy managers of enterprises, boiler operators, and maintenance engineers, with good results. Technical assistance can be provided either in the form of free audits or audit assistance, technical advisory services, and referral services. All of the above services can be provided through appropriate institutions.

Energy audits of large and medium-sized energy-intensive facilities constitute the core of any industrial energy savings program. Energy audits are necessary to estimate the energy savings potential, identify the individual energy savings measures to be taken, and estimate their investment cost and impact on operating costs. Depending on the energy consumption level of each facility, the complexity of the in-plant energy

Exhibit 6.7

Typical Shares of Energy Costs Within Total Production Costs[1]

	Share of energy cost (percent)
Highly energy-intensive products	
Ammonia	40-50
Cement	40-55
Energy-intensive products	
Aluminum	25-30
Fertilizers	20-25
Steel	17-30
Glass	15-25
Paper	15-25
Other products	
Ceramics and construction materials	12-20
Metallurgy	3-15
Textile finishing	6-12
Food products	3-10

[1]Expressed as ratio of total energy cost (i.e., fuels and electricity) to total production costs, including depreciation.

SOURCE: World Bank.

distribution and utilization systems, and the objectives pursued, several types of audits can be designed.

Energy audits can be performed either on a voluntary or a mandatory basis. The latter case is generally used for establishments exceeding a certain energy consumption threshold (e.g., 1,000 toe per year). Some countries also provide subsidies for energy audits or provide free brief audits, often with the help of mobile energy diagnosis equipment. Crucial to the effective performance of an overall energy auditing program is the development, through training, of domestic energy auditing capabilities.

A useful complement to an energy auditing program is the training and appointment of energy coordinators or energy management teams in the major energy-consuming enterprises to ensure a follow-up of the energy audits and to help introduce better energy management practices throughout the facility. The role of the coordinators or teams can be either voluntary or mandatory.

A typical training program incorporates at least the following elements:

1. A 2-day seminar for senior officials of the ministries concerned, senior managers of public- sector corporations, and general managers of major energy-consuming industries and power plants, to create awareness of the importance of energy efficiency in industrial management.
2. A workshop (about 3-4 days) for energy coordinators and energy managers to develop awareness and provide understanding of energy conservation activities.
3. On-the-job training of government staff, energy coordinators, and energy auditors.
4. Seminars for representatives of private-sector industries, trade associations, and the Chamber of Commerce to make them aware of benefits from energy conservation activities.

Financial Assistance

Most industrial countries (ICs) -- and some LDCs -- have formulated national industrial energy savings programs that provide, at least initially, some financial assistance and incentives. Despite the inherently attractive returns on energy savings investments, such assistance has proved necessary to overcome the disinclination to make energy conservation investments, even where energy prices constitute an adequate incentive. Owing to their relatively modest size and impact on total production costs, many energy conservation investments receive a low priority within the enterprises' investment budget. In general, grants for energy conservation -- used to some extent in industrialized countries -- have been phased out and replaced over time by preferential interest rates, accelerated depreciation, and other tax-related incentives, including duty tax exemption for imported equipment. Subsidies for energy audits have been maintained in many countries. In many LDCs, the prices of the key energy products used by industry are substantially below international price levels, and therefore provide little incentive to firms to invest in energy-saving facilities. In these cases, some form of financial assistance for capital investments might be needed during the **transition period**, provided that its amount is reduced as energy prices are gradually increased. The desirability of such a subsidy should, however, be weighed against the merits and feasibility of a policy of faster energy price increases.

It is also necessary to provide adequate access to medium-term financing for energy savings investments, particularly in the case of small or medium-sized enterprises with only a few relatively small energy conservation projects. Normal banking channels might entail unduly cumbersome and time-consuming procedures and collateral for such simple investments. Simpler forms of medium-term financing that are worth studying in this respect include financial leasing or acceptances.

Institutional and Regulatory Aspects

Industrial energy pricing is an integral part of overall energy pricing and should normally be handled through the energy pricing framework existing in most countries. There are, however, a variety of specific institutional and regulatory mechanisms that can be envisaged for the remaining elements of the industrial energy conservation programs mentioned above.

Since 1973/1974, **most LDCs have considered establishing energy conservation centers** that deal mainly with industry. Such centers emphasize the technical assistance functions mentioned above, often in collaboration with other training or technical assistance entities, and sometimes with private-sector participation. However, a few LDCs -- e.g., Portugal, Bangladesh, Pakistan, Thailand, Turkey, China -- to date have established such centers or are in the process of doing so. To have maximum impact, the centers should be constituted and staffed on the basis of an in-depth review of the nature of the industrial sector in the country, the potential for energy savings, and the capabilities of the domestic technical specialists. These centers are only rarely involved directly in financial assistance (particularly because energy conservation grants have gradually yielded to loans with preferential interest rates and tax incentives, at least in most ICs). All of these centers render information and promotion services, and most sponsor training programs. Among the latter, the training of plant energy managers and local energy auditors is of special importance.

While the regulatory framework varies from country to country, many ICs and some LDCs have enacted a basic energy conservation law of a very technical nature. In most cases, energy consumption standards are foreseen for boilers, furnaces, and other combustion units, and sometimes for industrial lighting, space heating, and other items. Energy consumption standards by product are significantly more difficult to establish and administer. The record varies considerably from country to country as to the usefulness of and compliance with such standards. Other important aspects generally covered by regulations, and of particular interest to most LDCs, are the mandatory appointment of energy managers and the mandatory performance of energy audits in industrial establishments that exceed **minimal** energy consumption standards.

The experience of most ICs with energy conservation programs indicates that to be successful, energy conservation regulations should be complemented by appropriate measures for promotion, incentives, and free technical assistance. The exact blend of "carrot and stick" needs to be considered in the light of individual country circumstances and likely industry response.

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EXPERIENCES OF SELECTED COUNTRIES

A review of past and planned industrial energy conservation programs in several ICs and LDCs indicates that the reduction of industrial energy consumption is an objective common to most countries. While most industrialized countries initiated efforts to use less energy in 1974, only a handful of LDCs -- led by the Republic of Korea (ROK) -- reacted equally quickly to the first oil price shock. By the end of the 1970s, other LDCs -- mainly in Southeast Asia, North Africa, and South and Central America -- had begun to respond to the second large oil price increase. To date, LDCs in the Middle East and equatorial Africa (except Kenya) have placed little emphasis on cutting energy use.

The ICs generally initiated a conservation program that embraced all sectors, with emphasis on the transportation, residential, and commercial sectors, which offer significant short-term energy savings at low cost. LDCs, on the other hand, generally emphasized industrial energy conservation, in part because industry in LDCs accounts for a higher share of total energy consumption than it does in ICs.

In their initial phase (1974-1980), these programs have varied widely with respect to key program elements such as institutional set-up, energy pricing, legislation and regulations, incentives, technical and financial assistance, and financing channels used to provide financial assistance. Both results and expected savings are highly country-specific; in addition to the conservation policy itself, they depend on such factors as industry structure, industry energy efficiency, and the level of existing legislation and regulations on energy conservation.

Some countries have apparently achieved impressive energy savings (expressed as a physical amount of energy per physical unit of output), while others -- in some cases, countries with very stringent programs -- have performed poorly. For example, energy-efficiency leaders like Sweden and France achieved only about 6 percent savings over the 1974-1980 period, whereas the United States achieved more than 10 percent. However, to accurately gauge program succcess, the initial energy efficiency level must be taken into account. In this case, Sweden and France started with a ratio of industrial GDP to industrial energy used of approximately U.S. $2,000/toe (1975 dollars); the

United States, on the other hand, began with a ratio of less than U.S. $1,000/toe. Although all LDCs started from a low efficiency level, their results have been mixed.

In the following sections, we first summarize and attempt to analyze the various elements of the IC and LDC programs. Then, we summarize the key lessons that can be drawn from the countries' experience.

Program Initiation

Most ICs, but only a few LDCs, started industrial energy conservation efforts after the first big oil price increase in 1973. Attention in LDCs focused instead on obtaining external financing to cover the additional energy costs. By the end of the 1970s, however, almost 20 LDCs were designing industrial energy conservation programs to counteract the second oil price hike, out of domestic political necessity, and because of pressure from international financial organizations.

Institutional Set-Up

Both ICs and LDCs implemented energy information and awareness campaigns using their appropriate government agency (generally a Department of Energy or a Department of Industry). In many cases, efforts to organize the program faltered, usually because too many government bodies were involved in the decision and implementation process, and sufficient coordination and authority were lacking (e.g., Sweden, Korea). While most countries understood the need to create a new organization -- or expand an existing one -- to oversee industrial energy conservation, there have been many "trials and errors" with respect to (1) its proper location within the government organization, (2) the extent of its role (advice vs. implementation), (3) its staffing (5 or 500 people), (4) its responsibility with respect to regulation, legislation, and financial matters, and (5) its scope (selected sectors or all sectors).

On the basis of the experience of the various countries that have been reviewed, the best structure appears to be one consisting of three bodies:

1. **A policy group**, placed directly under the appropriate minister (energy, industry, planning), whose prime responsibilities are to design the energy conservation program, ensure coordination with other entities, and assume overall responsibility for energy conservation matters. This policy group may also be in charge of program evaluation.
2. **An implementing agency** (e.g., AFME in France, KEMCO in Korea), placed under the policy group and headed by a director, with or without direct industry participation, whose prime function is to implement the program adopted by the government. Its main activities are conducting information and awareness campaigns and audits, and promoting and monitoring overall energy conservation activities.
3. **A research center**, also placed under the policy group, staffed with 10-20 researchers responsible for carrying out all types of studies, data collection, and analysis required for policy planning and evaluation. The research center can also be in charge of conducting technical research and development on energy-saving technologies/equipment to help their penetration of the local market. In LDCs with low industrial energy use, the research center may not be necessary to get the program under way.

Program Goals and Scope

In the early stage of the program, very few countries had set energy conservation goals just for industry. Moreover, industrial energy efforts focused on housekeeping measures and low-cost energy savings measures. France and Sweden had national goals for industry, while the United States had a set of voluntary goals in selected energy-intensive industries. Although none of the announced national goals for industry has been reached, voluntary energy conservation program goals have been exceeded in the three countries that had such programs (France,* the United States, Japan).

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*France set both national goals and voluntary energy conservation program goals in selected industries.

Incentives and Policies

There has been much talk of the benefit of "market" energy prices, especially since 1979, but energy markets are far from "free" even now. Most countries embarked on conservation programs at a time when price controls and regulations were particularly heavy. Domestic oil prices have generally increased to reflect higher acquisition costs,* and additional taxes or "surcharges" have been levied on residual oil (e.g., France until 1980, Sweden). In contrast, much less has been done in other areas such as coal and electricity, which remain highly subsidized in many countries (e.g., coal in France, Germany, and Korea). The modification of electrical rates (tariffs) has been studied, but there is little agreement on how this is to be done.**

Nonetheless, it is the general belief in ICs and LDCs that energy prices should reflect medium- and long-term acquisition costs and that subsidies act as barriers to energy conservation. Again, practical implementation of such concepts is difficult because of the social issues involved.

In addition to energy pricing, countries with a substantial industry sector have provided a broad array of energy conservation incentives. The incentives include direct financial assistance (grants) for research, development, and demonstration (20 to 70 percent of total project cost) and for audits (100 percent for small and medium enterprises, and 50 percent for larger plants); soft loans (0.5 points to several points below market or prime with or without a grace period) for installing energy-efficient devices or equipment; and free technical assistance and information. The experience of the countries reviewed for the purpose of this report provides two facts worth noting:

- Countries -- especially LDCs -- with no financial assistance mechanism for project implementation obtained poor conservation results (e.g., Korea until 1980).

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*Except in oil-producing countries (e.g., Indonesia), where domestic prices are still much lower than international prices.

**The issue of revenue redistribution through utility rates is the focus of many debates both in ICs and LDCs.

- In most countries, but particularly in France and Sweden, grants established in 1974-1976 were eliminated in 1980 because such programs were expensive and inefficient; market prices alone generally made candidate projects financially attractive.

Most ICs offer additional financial incentives such as tax credits, accelerated depreciation, easier access to credit, and nonrefundable funds in case of project failure. LDCs also generally consider or provide duty tax exemptions for improved energy savings equipment. In most ICs, but in very few LDCs, energy conservation equipment manufacturers enjoy substantial public aid and preferential tax treatment. Exhibit 6.8 provides a summary of the financial incentives made available for industrial energy conservation in selected ICs and LDCs.

Technical Assistance Program

Developed countries required several years to recognize the need for, and subsequently organize, an auditing program in industrial facilities. A key reason for the delay was the lack of qualified auditors (prior to 1974, there was no such job). In addition, industry was sometimes reluctant to have outside people gathering detailed operating information on their processes (particularly in the case of chemicals). With the exception of the United States,* all countries reviewed had a national auditing program, often mandatory, especially for large oil users (generally above 500-1,000 toe/year). For small and medium users, audits are voluntary, and often provided free of charge.

With respect to industrial energy auditing, LDCs have made audits mandatory for so-called "designated facilities" (e.g., Korea, the Philippines). Less stringent approaches (e.g., Thailand) have not been successful.

All ICs and LDCs have strongly emphasized energy awareness and information, relying on conventional media (e.g., booklets, pamphlets, television spots, forums, conferences)

*There is no federal audit scheme in the United States. In some cases, however, there are audit programs at the state level.

Exhibit 6.8

Experience from DCs and LDCs: Financial Assistance

	Grants		Loans		Other	
	Audits	Projects	Preferential interest rates	Extended grace period	Tax credits and duty tax exemption	Accelerated depreciation
Developed countries						
United States					X	
Japan	X		X		X	X
Germany	X		X		X	
France	X	(X)	X	X	X	X
United Kingdom	X	(X)				
Sweden	X	(X)	X	X		
Developing countries						
Korea	X					
Brazil			X	X		
Thailand	(X)		X			
Philippines	X		X	X	X	X
India			(X)			

NOTE: (X) = in preparation or limited application.

SOURCE: Hagler, Bailly & Company.

and more innovative vehicles (e.g., the concept of having an instrumented bus travelling across the country in Canada and Japan, energy efficiency contests in Korea).

Technical assistance has consisted mostly of training energy managers and auditors. In LDCs, foreign assistance is generally required in this area, except in those countries with a broad industrial base and energy experience (China, Brazil, India). Exhibit 6.9 provides a summary of the technical assistance available for industrial energy conservation in selected ICs and LDCs.

Legislation and Regulations

The legislative and regulatory framework can be kept to a minimum in ICs, where price signals and financial and technical assistance are powerful enough to ensure significant savings. However, LDCs' experience provides ample evidence that regulatory means are necessary to achieve program goals. Legislation (e.g. energy utilization or rationalization law, energy conservation law, or "an act to further promote energy conservation," as in the Philippines) is generally required. Its implementation may involve a large number of government bodies in several ministries, as well as the key components of the industrial energy conservation institutional set-up (see "Institutional Set-Up," above). Regulations resulting from the law cover a broad range of energy-related activities and equipment, including lighting and space heating in industrial buildings, combustion efficiency of large boilers and furnaces, electric power factor, replacement of old energy-using equipment, and fuel diversification (e.g., United States, United Kingdom, Sweden). Exhibit 6.10 presents examples of regulations related to industrial energy conservation in selected ICs and LDCs.

Quotas on oil consumption and supply interruptions have also been used in some cases (e.g., France, United States, Thailand).

RECOMMENDATIONS FOR PROGRAM DEFINITION AND IMPLEMENTATION

The selection of the type of industrial energy conservation program that a country might wish to implement depends greatly on the program's ease of implementation and

Exhibit 6.9

Experience from DCs and LDCs: Technical Assistance

	Audits				Training		Other
	Large plants		Small and medium plants				
	Mandatory	Voluntary	Mandatory	Voluntary	Auditors	Plant energy manager	Information program
Developed countries							
United States		X		X			X
Japan		X		X	X	X	X
Germany		X		X	X	X	X
France	X			X		X	X
United Kingdom	(X)			X		X	X
Sweden		X		X		X	X
Developing countries							
Korea	X				X	X	X
Brazil		X		X		X	X
Thailand	(X)			X	X		X
Philippines	X				(X)	(X)	X
India		X		X			

NOTE: (X) = in preparation or limited application.

SOURCE: Hagler, Bailly & Company.

Exhibit 6.10

Examples of Industrial Energy Conservation Regulations
in Selected Developed and Developing Countries

	Energy conservation law	Combustion standards
Developed countries		
United States	X	(X)
Japan	X	(X)
Germany	X	
France	X	X
United Kingdom	X	X
Sweden	X	
Developing countries		
Korea	X	X
Brazil	X	
Thailand	(X)	
Philippines	X	(X)
India	X	X

NOTE: (X) = in preparation or limited application.

SOURCE: Hagler, Bailly & Company.

administration.* In turn, the relative ease of implementing and administering a program depends on factors such as the need for new legislation and the strength of vested interests that would oppose any change in the status quo, as well as the number of people or organizations -- public and private -- that must be managed or coordinated to successfully carry out the objectives of the program. It is therefore essential that a country's available institutional and regulatory resources be systematically inventoried and evaluated before any decision is made on the management structure. Only when this assessment has been carried out and the institutional and regulatory deficiencies have been identified can recommendations for modification of the existing institutional and regulatory environment be made.

The institutional assessment should focus not only on government institutions, but on the institutional resources available in the private sector (e.g., trade associations, oil companies, architect/engineering firms) and quasi-public sector (e.g., nationalized companies, utilities, universities). The institutional problems most often encountered are:

- Lack of clearly articulated objectives
- Lack of coordination among government institutions
- Conflicting and sometimes contradictory responsibilities
- Lack of managerial and technical resources.

The successful implementation of any program, measure, or task requires that four fundamental management functions be carried out:

- Initiating, which sets the activity in motion
- Performing, which encompasses the day-to-day management or performance of the activity
- Funding, which ensures that the committed funds are delivered in time for proper performance
- Monitoring and enforcing, which involves overseeing other participants' performance, adjusting activities to accommodate changing circumstances, and enforcing applicable standards or regulations.

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*Other criteria must also be considered -- e.g., potential energy savings, degree of private-sector involvement without government support, direct gross public costs, potential

Each of these management functions can be carried out by a different institution. What is important is that each function be performed in an effective and timely manner.

Once the tasks associated with the implementation of a program or a specific conservation measure have been identified, a **simple matrix** that arrays the four management functions with the specific tasks can be used to inventory and define the roles of the various public- and private-sector organizations that might be involved in the process. The same framework can be used to identify potential coordination problems that might exist across conservation measures.

Exhibit 6.11 presents an example of how the various management functions might be assigned in a hypothetical country where public- and private-sector institutions are already in place. For instance, several tasks (e.g., organization and conduct of survey, data base development) might be carried out by the National Institute of Statistics. A task force composed of representatives from the key ministries, national energy companies, universities, and industries could be created to participate in the design of the program. Once the energy conservation center has been created, it serves as the focal point for carrying out the mandate of the program, although it relies as much as possible on existing entities to perform some of the specific tasks. It can be seen from this example that the institutional arrangements are unlimited, and depend on whether program management is highly centralized or decentralized.

The existing institutional framework will often dictate the proper management structure. In the interests of objectivity and credibility, the experience of various countries has shown that **the organization(s) pursuing policy development activities should be separate from the organizations responsible for policy implementation.**

The degree of management centralization will also be dictated by the existing institutional and regulatory environment. In the past few years, many countries have taken steps -- albeit limited ones -- toward improving the energy efficiency of their industrial sector; in many cases, existing ministries and government institutions have started to implement some conservation measures. A successful country-wide energy conservation

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(cont.)
for adverse socioeconomic impacts.

Exhibit 6.11

Example of Institutional Arrangements

Phase/task	Management functions: Initiate	Perform	Fund	Monitor
I. Design				
Organize and conduct energy survey	MOI	NIS, E, U	MOF	MOI
Identify barriers to conservation	MOI	TF, U	MOF	MOI
Analyze and recommend institutional modifications	MOI	TF, U	MOF	MOI
Review and propose modifications of existing laws and regulations and energy pricing policy	MOI	TF, U	MOF	MOI
Process energy survey	MOI	NIS, E, U	MOF	MOI
Identify alternative programs	MOI	MOI	MOF	MOI
Estimate costs and benefits of alternative programs	MOI	MOI	MOF	MOI
Evaluate resources needed for each alternative	MOI	MOI, MOF	MOF	MOI
Review options for financing and incentives	MOI	MOI, TF	MOF	MOI
II. Start-Up				
Finalize national program	MOI	MOI	MOF	MOI
Set up organization	MOI	MOI	MOF	MOI
Launch awareness and information campaigns	ECC	TA, MOI	MOF	ECC
Develop auditing program	ECC	ECC, U, E	MOF	ECC
Recruit and train auditors	ECC	ECC, U, E	MOF	ECC
Conduct test audits	ECC	ECC	MOF	ECC
Organize financing channels	ECC	ECC, MOF	MOF	ECC
Adapt laws and regulations	ECC	MOJ	MOF	ECC
III. Implementation				
Define and publicize conservation goals and/or standards	ECC	ECC, MOI, TA	MOF	ECC
Conduct auditing program	ECC	ECC, U, E	MOF	ECC
Implement training program for energy auditors	ECC	ECC, U, E	MOF	ECC
Evaluate and implement projects	ECC	ECC	MOF	ECC
Monitor results	ECC	ECC, NIS	MOF	ECC
Develop data base	ECC	NIS	MOF	ECC

MOI = Ministry of Industry
ECC = Energy Conservation Center
U = Universities
E = Engineering firms
TF = Task force
MOF = Ministry of Finance
NIS = National Institute of Statistics
MOJ = Ministry of Justice
TA = Trade associations

SOURCE: Hagler, Bailly & Company.

program, however, usually requires one central body to oversee the day-to-day implementation of energy-related activities.

The focus should be on substance and not form. It is important to involve all key parties-at-interest -- both from the private and public sector -- in the planning and (if necessary) implementation process.

In evaluating institutional and regulatory options, consideration must be given to the speed at which changes can be made. Any program that requires new legislative authority will generally be more difficult to implement than one that does not. Programs requiring local action (e.g., building code amendments) will be even more difficult to adopt nationally because of the numerous jurisdictions involved. Other less serious obstacles to implementation are requirements for new administrative regulations or rules, and requirements for agency reorganization. But perhaps the most important implementation criterion is the existence of public and political support for a program, or at least the absence of opposition. Political acceptance is as critical to tactical planning as it is to strategic planning.

SESSION 7: ENERGY CONSERVATION POTENTIAL IN MAJOR ENERGY-INTENSIVE INDUSTRIES

In this chapter, we present briefly the production characteristics of selected energy-intensive industrial products (i.e., steel, ammonia, bricks, cement, textile, cane sugar, vegetable oil, and paper) and estimate their conservation potential in LDCs.

STEEL

Steel production in LDCs was approximately 120 million tonnes in 1981. The annual growth rate in steel production has averaged 7.2 percent since 1974. Although 50 LDCs produce steel, five countries account for over two-thirds of all production: China, Romania, Brazil, Spain, and Korea.

Processes

There are four steel-making processes in use today:

- Blast furnace/basic oxygen furnace
- Blast furnace/open hearth furnace
- Direct reduction plant/electric arc furnace
- Electric arc furnace.

The first three processes are used in "integrated" steel mills (i.e., mills that integrate iron and steel making). The last two processes that employ electric arc furnaces are used in so-called "mini-mills," which are growing in popularity in developing countries. A mini-mill that incorporates a direct reduction plant is an integrated mini-mill. One that employs only an electric arc furnace and steel finishing operations is a non-integrated mini-mill. Mini-mills are typically much less expensive to build and can be erected more quickly than blast-furnace iron and steel mills.

Energy Consumption

The blast furnace/basic oxygen furnace process accounts for 37 percent of steel production in LDCs. In this process, iron ore, coke, limestone, and oil are fed into the blast furnace to produce pig iron. The molten pig iron is then mixed with scrap steel in the basic oxygen furnace and converted to raw steel. Total energy requirements for this process range from 420 to 470 kilograms (kg) of oil equivalent per tonne of raw steel. Coal accounts for 71 percent of the energy requirement, electricity, 16 percent, and oil and gas, 13 percent. A modern integrated steel mill using the blast furnace/basic oxygen furnace process typically has a production capacity of 2 to 3 million tonnes per year. Some older plants have a capacity as small as 500,000 tonnes per year.

The blast furnace/open hearth furnace process, which accounts for 32 percent of LDC steel production, uses the same inputs as the basic oxygen furnace, but it is slower and less energy-efficient. Energy requirements range from 600 to 1,400 kg of oil equivalent per tonne of steel. Typical plant capacity is 800,000 tonnes per year.

In the direct reduction/electric arc furnace, which accounts for 12 percent of LDC steel production, iron ore is processed in a hydrogen atmosphere and converted into sponge iron. The sponge iron, along with scrap, is fed into an electric arc furnace, where they are converted into steel. Energy requirements range from 430 to 480 kg of oil equivalent per tonne of raw steel. Natural gas accounts for 53 percent, electricity, 32 percent, and oil, 15 percent of the energy requirement. A typical capacity of a direct reduction steel mill is 500,000 tonnes per year.

The electric arc furnace using only scrap metal as an input accounts for 19 percent of LDC steel production. Energy requirements are 150 to 210 kg of oil equivalent per tonne. Electricity accounts for 59 percent of the energy input, and oil for 41 percent. A typical electric arc furnace steel mill produces 400,000 tonnes per year.

Steel finishing is the collection of processes used to convert raw steel (in the form of billets, slabs, and blooms) into finished products (e.g., pipe, tube, plate, coil, wire, structural forms). These processes include reheating, hot rolling, cold rolling, forging, annealing, and casting. Most of the energy consumed in finishing operations is fuel for high-temperature furnaces.

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The amount of energy used in finishing depends on how many times the steel must be reworked, which in turn depends on the type of product. Steel finishing consumes from 100 to 300 kg of oil equivalent per tonne of steel.

In most LDCs, steel production accounts for a significant portion of industrial energy consumption. In Brazil and India, steel making uses over 30 percent of total industrial energy consumed. In India, the portion attributed to steel production only is 17 percent.

Energy Conservation

LDCs should be able to reduce specific energy consumption in steel making by 3 to 7 percent by employing measures that either have minimal cost (i.e., housekeeping measures) or a payback of less than 2 years. These measures include:

- Improving production scheduling to reduce inter-process holding time (thus minimizing the need for repeated reheating)
- Improving monitoring and control of air/fuel ratios in reheat furnaces
- Adding low-density ceramic fiber insulation to cycling furnaces
- Repairing skid pipe insulation in reheat furnaces
- Improving flue gas recirculation in all high-temperature furnaces
- Undertaking external desulfurization of blast furnace pig iron
- Switching from sintering to pelletizing as a means of agglomerating iron ore.

Medium-term measures that require larger investments can be expected to reduce specific energy consumption by an additional 15 to 20 percent. These measures include:

- Using high-temperature recuperators in soaking pits and annealing and forging furnaces

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- Using waste heat boilers on reheat furnaces

- Modifying blast furnaces

  - direct injection of powdered coal
  - dehumidification of blast air
  - top pressure recovery turbine

- Modifying coke-making plants

  - preheating coal prior to coking
  - dry quenching to reuse the sensible heat in hot coke.

In addition, both the continuing replacement of open hearth furnaces by basic oxygen furnaces and the increased recovery and reuse of scrap steel by steel manufacturers will help to reduce specific energy consumption.

Exhibit 7.1 provides information on investment costs and potential energy savings for these conservation measures.

AMMONIA

Worldwide production of fertilizer in less developed countries (LDCs) was approximately 35 million tonnes in 1980. Nitrogenous fertilizers, which include ammonium nitrate, nitric acid, and urea, are all derived from ammonia, the parent compound. About 95 percent of the energy consumed by the production of nitrogenous fertilizers is used in the synthesis of ammonia.

Processes

The most commonly used process for ammonia production is steam reforming of light hydrocarbons. This process, which accounts for 80 percent of worldwide production, consists of the following steps:

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Exhibit 7.1

Costs and Benefits of Selected Energy Conservation Measures

Industry: Iron & Steel

Process: Raw Steel

Typical range of specific primary energy consumption (SEC) in LDCs (in toe/ton): 0.8-1.1

	Measure/description	Energy saved (F = fuel, E = electricity)	Specific investment cost (installed) (1982 U.S. $/toe saved)	Potential energy savings (% of SEC)
A.*	Short-Term/Short-Payback			
1.	Pelletize iron ore instead of sintering	F	300-350	1.0-2.0
2.	External desulfurization of blast furnace iron	F	150-250	2.0-3.0
3.	Recover basic oxygen furnace off-gas	F	250-350	0.5-1.0
4.	Air dehumidification system for blast furnace	F	250-300	1.0-2.0
	Total (all measures not additive)		**250-350**	**3.0-7.0**
B.**	Medium-Term/Medium-Payback			
1.	Dry coke quenching	F	800-900	8.0-12.0
2.	Preheat coal prior to coking	F	800-1,200	4.0-7.0
3.	Inject pulverized coal into blast furnace	F	900-1,200	3.0-8.0
4.	Recover and use surplus blast furnace gas	F	900-1,200	3.0-7.0
	Total (all measures not additive)		**450-550**	**20.0-25.0**

*E.g., housekeeping, minor equipment retrofitting.
**E.g., equipment retrofitting, process modifications.

SOURCE: Hagler, Bailly & Company.

- Desulfurization of the feedstock
- Steam reforming
- Secondary reforming
- High-temperature and low-temperature carbon monoxide shift
- CO_2 removal
- Methanation
- Compression and ammonia synthesis.

Energy Consumption

Specific energy consumption for ammonia production from light hydrocarbon feedstock ranges from 800 to 1,100 kg of oil equivalent per tonne of ammonia. The average specific energy consumption is 1,000 kg of oil per tonne of ammonia. Approximately 94 percent of the energy input is fuel, and 6 percent is purchased electricity.

Ammonia plants range in capacity from 200 to 1,000 tonnes per day.

Energy Conservation

Specific energy consumption in ammonia production can be reduced by as much as 5 percent by housekeeping measures that require little capital investment. These measures include repairing and upgrading the thermal insulation on primary reformer surfaces, tuning the reformer burners, and fine-tuning the steam/carbon ratio to minimize steam consumption.

Energy consumption in most ammonia plants can be reduced by an additional 20 percent by the implementation of measures that are more capital-intensive but still pay back within 4 years. These measures include:

- Addition of a combustion air preheater to the primary reformer, using stack exhaust as a heat source
- Substitution of a physical process for CO_2 removal for the conventional MEA wash

- Recovery of hydrogen from the purge gas stream by hollow fibre separators
- Replacement of older gas compressors by more efficient compressors (particularly by substituting modern centrifugal compressors for reciprocating compressors in larger plants)
- Installation of modern automatic control systems in the byproduct steam generation system.

Because approximately 35 percent of the hydrocarbon input to an ammonia plant is burned to heat the primary reformer tubes, there is some potential for substitution of pulverized coal for oil and gas. There is also a potential for substituting a combustion turbine for the primary reformer burners. The turbine exhaust gases are ducted to the reformer tubes, and the turbine shaft power is used to drive the synthesis gas compressor. This system can eliminate the need to purchase electricity for ammonia production.

Investment costs and potential energy savings on short-term and longer-term conservation measures are shown in Exhibit 7.2.

BRICKS

Worldwide production of bricks in LDCs is estimated at 75 million tons in 1980.

Processes

Bricks are manufactured by one of three processes: the soft-mud, stiff-mud, or dry-press process. The stiff-mud process, which now predominates, extrudes clay containing 15 percent water into columns. The columns are then wire-cut into appropriate lengths, and the bricks repressed to make face brick. The wet bricks are dried and then fired in a kiln, generally at 980°C to 1,200°C.

The basic steps in brick-making are:

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Exhibit 7.2

Costs and Benefits of Selected Energy Conservation Measures

Industry: Chemicals

Process: Ammonia

Typical range of specific primary energy consumption (SEC) in LDCs (in toe/ton): 0.8-1.1

Measure/description	Energy saved (F = fuel, E = electricity)	Specific investment cost (installed) (1982 U.S. $/toe saved)	Potential energy savings (% of SEC)
A.* **Short-Term/Short-Payback**			
1. Improve insulation of primary reformer	F	50-150	1.3-2.5
2. Insulate steam piping	F	50-150	0.5-1.5
3. Use physical solvent for CO_2 removal	E	200-250	0.5-2.0
Total (all measures not additive)		175-200	2.0-5.0
B.** **Medium-Term/Medium-Payback**			
1. Recover H_2 from purge gas by hollow fiber membrane	F	400-600	10.0-15.0
2. Add combustion air preheater to primary reformer	F	600-700	10.0-15.0
3. Modify process (e.g., more efficient burners, gas turbine, changing steam/carbon ratio, replacing small turbines with electric motors)	F	450-550	15.0-20.0
Total (all measures not additive)		450-550	20.0-25.0
Fuel Substitution			
Substitute coal for natural gas in steam generation	F	400-500	

*E.g., housekeeping, minor equipment retrofitting.
**E.g., equipment retrofitting, process modifications.

SOURCE: Hagler, Bailly & Company.

- Mining the clay
- Crushing and grinding the clay
- Mixing the clay with water and forming bricks
- Drying bricks
- Firing bricks.

Energy Consumption

About 95 percent of the energy used in brick-making is consumed in the firing step. Approximately 90 percent of the total energy used is fuel (natural gas is the preferred fuel); 10 percent is electricity.

Specific energy consumption in brick-making ranges from 90 kg to 200 kg of oil equivalent per tonne of bricks. The average specific energy consumption is about 120 kg of oil per tonne.

Energy Conservation

Energy use in brick-making can be reduced by 10 to 15 percent by short-term measures that require modest capital investment. These measures include:

- Using kiln exhaust gases for drying (if not already done)
- Installing fans to recirculate kiln exhaust gases
- Adding insulation to ductwork and other hot surfaces not adequately insulated
- Adjusting kiln burners.

Measures that reduce energy consumption by an additional 50 percent require large capital investments that can be implemented in the medium-term. These measures include:

- Replacing older batch kilns with modern, continuous tunnel kilns
- Installing recuperators to recover waste heat for preheating combustion air.

There is considerable potential for fuel diversification in brick-making. Coal or biomass can be substituted for gas or oil. This substitution, however, may require substantial modification of the kiln, or even replacement of the existing kiln with a unit especially designed to burn coal or biomass fuel.

The investment costs and potential energy savings of conservation measures are shown in Exhibit 7.3.

CEMENT

Cement production in LDCs amounted to 373 million tons* in 1980, or 42 percent of total world production, estimated at 879 million tons. Of the LDCs, China is by far the major producer, with 73.5 million tons in 1980 (20 percent of total LDC production). Of the other major cement producers, Brazil is next (27.2 million tons), followed by India (17.8 million tons), Mexico (16.3 million tons), Romania (16 million tons), Korea (15.6 million tons), and Turkey (11.9 million tons). Most other LDCs produce less than 6 million tons per year.

There are two basic processes in cement manufacturing: the <u>wet</u> and the <u>dry</u> process.**

In the wet process, the raw materials (mostly clay and limestone) are first crushed and proportioned and then ground with water, thoroughly mixed, and finally fed into a rotary kiln in the form of slurry, where the high-temperature chemical reaction called

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*"Energy Efficiency in the Cement Industry," draft report. The World Bank, 1982.

**Other intermediary processes, called semi-dry and semi-wet, are also referred to, but are less common in LDCs. Semi-dry and semi-wet processes differ from conventional dry and wet processes by the adjunction of a grate preheater. Multistage (2-4) preheaters with or without precalciner are the most energy-efficient of recent process developments.

Exhibit 7.3

Costs and Benefits of Selected Energy Conservation Measures

Industry: Brick manufacturing

Process: All

Typical range of specific primary energy consumption (SEC) in LDCs (in toe/ton): 0.09-0.20

	Measure/description	Energy saved (F = fuel, E = electricity)	Specific investment cost (installed) (1982 U.S. $/toe saved)	Potential energy savings (% of SEC)
A.*	Short-Term/Short-Payback			
1.	Simple combustion controls	F	100-200	2-3
2.	Add ceramic fiber insulation to kiln	F	100-200	2-3
3.	Recirculate kiln gas	F	150-250	3-7
4.	Recovery kiln gas for use in dryer	F	250-350	10-20
	Total (all measures not additive)		**200-300**	**10-15**
B.**	Medium-Term/Medium-Payback			
1.	Stack gas recuperation	F	400-600	10-15
2.	More sophisticated control system (e.g., moisture)	F	500-650	5-10
3.	Kiln rebuilding	F	400-800	5-10
	Total (all measures not additive)		**450-650**	**15-20**

*E.g., housekeeping, minor equipment retrofitting.
**E.g., equipment retrofitting, process modifications.

SOURCE: Hagler, Bailly & Company.

"pyroprocessing" or "clinkering" takes place. The result of the reaction is called "clinker." After cooling, clinker is mixed and ground again with additives to form cement.

The dry process differs from the wet process primarily in its preparation stage. In the dry process, the raw materials are ground and predried with recovered hot kiln gases, homogenized, and fed into the kiln in their dry state. The remaining steps are similar to those of the wet process.

The share of the wet process in LDCs is currently -- and is expected to remain -- 30-35 percent of total cement production.

Energy Consumption

While cement is less energy-intensive than many other basic industrial products such as steel, glass, petroleum products, and chemicals, cement manufacturing consumes a larger portion of total commercial energy than any other industry in LDCs.* The reason is that the quantity produced is much larger than in most other industries. Based on an annual production of 373 million tons and an average specific thermal energy consumption of 0.12 toe/ton of cement, total fuel consumption for cement manufacturing amounts to 45 million toe. More importantly, oil is the major fuel used, except in China, India, and Argentina, which burn mainly coal. Electric power consumption is also significant. Total electricity consumption for cement manufacturing is estimated at 37 billion kWh, using an average specific electricity consumption of 100 kWh/ton.**

Specific energy consumption depends primarily on the process used:

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*It is estimated that the cement industry consumes 2 to 6 percent of total commercial energy in most LDCs. However, in some countries, this percentage is much higher (e.g., 40 percent in Togo).

**Equivalent to 10 million toe of primary fuel consumption at the thermal power plant.

Process	Total energy consumption (kcal/kg of clinker)	Energy efficiency (%)
Wet	1,400	30
Semi-wet (grate preheater)	950	44
Semi-dry (grate preheater)	835	50
Dry (long rotary kiln)	965	43
4-stage preheater	800	52
4-stage preheater/precalciner	750	56

SOURCE: Lafarge Cimenterie.

Other factors influencing the specific energy consumption include the age of the plant, the raw material characteristics (which dictate the process to be used), the type of operation, and the type of fuel used.

Energy Conservation

Specific energy consumption is typically 10-20 percent higher than that of industrialized countries, indicating substantial potential for conservation, given that the cement industry consumes a large percentage of commercial energy, and oil is the major fuel used in that industry in most LDCs.

Short-Term Measures

There are several typical measures that can be implemented in LDCs to reduce energy consumption at low cost and within a short time frame. Such measures are listed below for both wet and dry processes:

- Improve combustion efficiency (e.g., reduce excess air)
- Improve raw material preparation (increase homogeneity)
- Reduce primary air leakage
- Increase kiln thermal insulation
- Install auxiliary burners in crude preheating zone (dry process only)
- Reduce excess water content in slurry (wet process only)
- Reduce heat losses
- Produce hot water from exhaust gases
- Improve kiln heat transfer
- Improve cooler waste heat recovery
- Use fly ash
- Increase additive content in cement
- Increase power factor.

Representative costs and benefits of these measures are shown in Exhibit 7.4. Based on the hypothetical case of an average LDC, a representative combination of all of the above measures is likely to result in approximately 9 percent energy savings in the dry process and 11 percent in the wet process.

Longer-Term Measures

Other measures that can reduce energy consumption involve substantial capital expenditures. These measures are process-specific:

- Dry process

  - increase waste heat recovery for crude preheating
  - install/increase stages in suspension preheater
  - install flash furnace
  - install process controls
  - modify/replace grinders (roller mills)
  - use oxygen enrichment techniques
  - cogenerate electricity (topping or bottoming)
  - increase kiln capacity

Exhibit 7.4

Costs and Benefits of Selected Energy Conservation Measures

Industry: Cement

Process: Wet and dry

Typical range of specific primary energy consumption (SEC) in LDCs (in toe/ton): 0.09-0.21

Measure/description	Energy saved (F = fuel, E = electricity)	Specific investment cost (installed) (1982 U.S. $/toe saved)	Potential energy savings (% of SEC)
A.* Short-Term/Short-Payback			
1. Improve kiln combustion efficiency (burner modification and controls, reduce excess air)	F	150-350	1.5-5.0
2. Increase kiln insulation (and fix leaking seals)	F	200-800	2.0-5.0
3. Install auxiliary burners in crude preheating zone	F	350-450	1.5-2.5
4. Install/improve WHR boiler combustion controls**	F	200-250	—
5. Use fly ash as a raw material (also bottom ash, slag)	F	N/A	8.0-15.0
6. Increase additive content in cement	F	Negligible	5.0-10.0
7. Reduce water content in slurry; use surface active agents and filter press	F	N/A	2.0-5.0
8. Produce hot water from exhaust gases	F	100-200	
9. Increase power factor and other housekeeping measures	E	200-300	1.0-5.0
Total (all measures not additive)		225-275	9.0-11.0
B.* Medium-Term/Medium-Payback**			
Wet process			
1. Increase waste heat recovery for crude preheating	F	300-800	10.0-32.0
2. Install process controls	F	200-600	1.0-3.0
3. Modify grinders (from ball to roller)	E	600-2,000	0.5-2.0
4. Increase kiln speed, length, capacity	F	600-1,000	1.0-5.0
5. Convert from oil/gas to coal or waste fuels	F	400-1,000	—
6. Cogenerate electricity (topping or bottoming system)	E, F	400-800	2.0-5.0
7. Convert to dry process (all sources)		1,000+	20.0-40.0
Total (all measures not additive)		700-800	15.0-20.0
Dry process			
1. Increase waste heat recovery for crude preheating (all sources)			
2. Install/increase stages in suspension preheater	F	500-700	10.0-25.0
3. Install flash furnace (precalcination)			
4. Install process controls	E, F	400-500	1.0-3.0
5. Modify grinders (roller mills) (all)	F	800-1,000+	2.0-3.0
6. Increase kiln capacity (length, speed)	E, F	800-1,000+	1.0-3.0
7. Convert from oil/gas to coal	E	400-800	—
8. Oxygen enrichment	E	600-1,000	3.0-11.0
9. Cogeneration (topping or bottoming)	E, F	400-600	2.0-5.0
Total (all measures not additive)		750-850	20.0-25.0

*E.g., housekeeping, minor equipment retrofitting.
**Mostly on wet kilns.
***E.g., equipment retrofitting, process modifications.

SOURCE: Hagler, Bailly & Company.

- Wet process

  - increase waste heat recovery for crude preheating
  - install process controls
  - modify/replace grinders (roller mills)
  - cogenerate electricity
  - increase kiln capacity (speed, length)
  - convert to dry process.

This last option, which is widely contemplated in LDCs, is a major capital expenditure. Conversion can be full or partial. A **full conversion** requires a drastic modification in the raw material preparation, which can be feasible only at the cost of installing expensive handling and preparation equipment. Full conversion can be made according to one of the three following alternatives:

- Long dry kiln
- 1- or 2-stage preheater kiln
- 4-stage preheater or precalciner kiln.

For a 1,000-tpd kiln, capital costs would be approximately U.S. $17 million, $45 million, and $55 million, respectively. The corresponding fuel savings rates would be approximately 35 percent, 38 percent, and 41 percent, respectively.

Raw material characteristics may prevent full conversion (e.g., extremely high natural moisture content). In this case, only **partial conversion** is possible. There are three basic alternatives:

- Grate preheater with filtration
- 2-stage preheater with filtration and dryer
- 4-stage preheater/precalciner with filtration and dryer.

Typical fuel savings are 30 percent, 35 percent, and 39 percent, respectively, or only slightly less than the savings achieved under full conversion. Capital costs are on the same order of magnitude as full conversion.

Conversions from wet to dry should not be contemplated for energy savings alone, which would not generally justify the investment.* The major benefit of conversion is the ability to significantly increase plant output (by 10 percent, 30-60 percent, and 50-80 percent for each alternative, respectively).

For a typical LDC cement plant, medium-term energy conservation alone can save an estimated 15 percent of the fuel used in a wet process plant and 20 percent of the fuel used in a dry process plant. Conversion from wet to dry can save an average of approximately 35 percent.

Switching from oil or gas to coal also represents a major opportunity to cut energy costs. Successful examples of such large-scale programs exist in France and Japan. The problem facing LDCs when considering conversion to coal are (1) coal availability and delivered price** and (2) the large capital cost of the conversion (U.S. $1.5-5 million for a 1,000-tpd kiln).

TEXTILES

The production of textiles in LDCs was approximately 12 million tonnes in 1981. The textile industry has been on the rise in LDCs because the labor-intensive technology provides a good match with manpower availability.

Processes

In the textile industry, finishing equipment is among the major energy-consuming machinery. Approximately 60 percent of the total energy used in the textile industry is consumed in the finishing process, also known as the wet process. During this process, the yarn or fabric is prepared, dyed, coated, and waterproofed or otherwise finished.

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*Assuming a conversion cost of U.S. $20,000/tpd, the payback would be roughly 6-7 years.

**The price differential between oil and coal has substantially decreased since 1979.

Energy Consumption

Wet processes predominately use thermal energy for heating water, fixing and curing chemicals, dyeing, and heat setting. Energy is either transformed and used indirectly as steam (e.g., in heating dye liquors) or used directly by fuel combustion (e.g., in drying operations). Specific energy consumption in textile production ranges from 950 kg to 2,500 kg of oil equivalent per tonne of textile product. The average energy consumption is 1,600 kg of oil equivalent per tonne of textiles.

Energy Conservation

Specific energy consumption in the textile industry can be reduced by about 6 percent by housekeeping measures requiring little financial investment. These measures include the maintenance of steam traps, an increase in the power factor on electric motors, and improved operational control in terms of lighting, scheduling, and maintenance control.

Energy consumption can be reduced further using more capital-intensive measures that have a payback of less than 2 years. The measures apply to either the boilers or the steam system. For the boilers, these measures include:

- Installation of air-fuel ratio control
- Installation of waste-heat recovery from blowdown.

For the steam system, these measures include:

- Repair or installation of insulation on steam lines and tanks
- Addition of a condensate return system.

In the longer term, specific energy consumption could be further reduced by approximately 50 percent using energy conservation measures having a payback period of over 2 years. These measures include:

- Replacement of existing boilers with newer, more efficient gas/oil boilers
- Installation of waste-heat recovery devices on such equipment as dye baths and dryers
- Modifications in bleaching and dyeing processes
- Use of waste as fuel
- Installation of back pressure turbines to generate electricity in large plants, primarily when burning coal or waste fuels
- Installation of economizers on boilers.

Costs and benefits of these various measures are presented in Exhibit 7.5.

FOOD

Although reliable statistics do not exist, the amount of energy used in food manufacturing appears to be relatively high in LDCs. Whereas beet sugar, milk, and animal feed tend to be the major food products in DCs with respect to total energy used, cane sugar, vegetable oil, and canned products are the major energy-intensive food products in LDCs.

Cane Sugar

Raw Sugar

More than 90 percent of total sugar cane production occurs in LDCs. Most of the plants processing raw cane to produce raw sugar do not burn commercial fuels, but bagasse -- which is the cellulosic combustible by-product of cane crushing. Although plants often have excess bagasse, it is important to ensure that the bagasse is burned efficiently. Any energy saving in the process results in additional bagasse for other uses and saves commercial fuels at the national level.

On-site power generation (topping cogeneration) represents the most powerful means of achieving commercial fuel savings and should be encouraged. Other measures that can result in savings should be estimated from both the enterprise perspective and the national perspective. In cases where bagasse has no potential economic application in

Exhibit 7.5

Costs and Benefits of Selected Energy Conservation Measures

Industry: Textiles

Process: Finishing

Typical range of specific primary energy consumption (SEC) in LDCs (in toe/ton): 0.95-2.5

	Measure/description	Energy saved (F = fuel, E = electricity)	Specific investment cost (installed) (1982 U.S. $/toe saved)	Potential energy savings (% of SEC)
A.*	**Short-Term/Short-Payback**			
1.	Boiler: install air/fuel ratio control	F	200-300	2-5
2.	Boiler: install waste-heat recovery from blowdown	F	200-400	1-3
3.	Steam system: repair/install insulation on steam lines and tanks	F	100-200	up to 5
4.	Steam system: add condensate return system	F	200-300	5-10
5.	Steam system: repair leaks in steam traps	F	100-200	2-4
6.	All other housekeeping measures (operation, scheduling, lighting, maintenance, increase power factor on electric motors)	F	100-300	3-5
	Total (all measures not additive)		**225-275**	**12-15**
B.**	**Medium-Term/Medium-Payback**			
1.	Replace existing boiler with more recent, more efficient boilers (gas/oil)	F	300-500	10-15
2.	Install waste-heat recovery devices in process -- liquid-to-liquid	F	300-600	5-15
3.	Process modifications (dyeing, bleaching, etc.)	F	400-650	5-20
4.	Install backpressure turbine to generate electricity (cogeneration)	F	600-800	10-20
5.	Boiler: install economizers	F	400-600	5-10
	Total (all measures not additive)		**550-650**	**15-17**

*E.g., housekeeping, minor equipment retrofitting.
**E.g., equipment retrofitting, process modifications.

SOURCE: Hagler, Bailly & Company.

other plants,* however, the enterprise perspective -- based on financial value -- will result in very limited opportunities. Nonetheless, in most cases such applications exist, and should be subjected to careful economic analysis.

Cane Sugar Refining

In contrast, cane sugar refining makes extensive use of commercial fuels, primarily oil. Short-payback and longer-payback measures that can be taken in cane sugar refining are listed below:

- Short-term/short-payback measures
  - increase boiler combustion efficiency
  - install preheaters/economizers in boilers
  - recover waste heat from boiler blowdown
  - repair and increase steam system insulation
  - increase condensate return to boiler
  - recover flash steam.
- Medium-term/medium-payback measures
  - increase bagasse utilization
  - install bagasse dryer
  - install additional evaporator effect(s)
  - install vapor recompression systems
  - install cogeneration equipment
  - convert crystallization from batch to continuous operation.

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*The economics of bagasse are heavily dependent on the transportation cost, because bagasse has a low heat content per unit of weight and volume, owing to the high moisture content. In addition, special boilers and handling equipment are necessary.

The costs and benefits of these measures are presented in Exhibit 7.6.

Vegetable Oil

Vegetable oil is another important energy-consuming industry in LDCs. A large portion of peanut oil, palm oil, olive oil, coconut oil, and cottonseed oil is produced in LDCs.

While there are some variations in the manufacturing processes, depending on the raw materials, the generic process involves the following common steps:

- Raw product cleaning (and eventually drying)
- Dehulling, cracking, or chopping
- Oil extraction (thermal or mechanical)
- Cooking
- Filtering.

Solvent extraction processes encompass an additional step of solvent recovery.

Typical specific fuel consumption ranges from 0.04 to 0.24 toe/ton of oil, with an average of approximately 0.08 toe/ton. Total primary energy used in LDCs for vegetable oil production averages 0.12 toe/ton of oil. With an estimated production of 17.3 million tons in 1980, total energy consumption is approximately 2 mtoe, which is relatively small.

Short-term measures, consisting primarily of combustion and steam system improvements, have the potential to save 8-10 percent of this energy. Medium-term/longer-payback measures can save up to 15 percent of this energy. These measures include waste heat recovery and boiler replacement.

PULP AND PAPER

Pulp and paper production in LDCs was approximately 24 million tonnes in 1980, or 14.2 percent of total world production (170.7 million tonnes). The major producers

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Exhibit 7.6

Costs and Benefits of Selected Energy Conservation Measures

Industry: Food

Process: Cane sugar processing (raw and refining)

Typical range of specific primary energy consumption (SEC) in LDCs (in toe/ton): 0.35-0.80

	Measure/description	Energy saved (F = fuel, E = electricity)	Specific investment cost (installed) (1982 U.S. $/toe saved)	Potential energy savings (% of SEC)
A.*	Short-Term/Short-Payback			
1.	Boilers: instrumentation — air/fuel ratio controls — replace burners	F	100-400	2.0-10.0
2.	Boilers: install economizer/air preheater	F	300-500	5.0-10.0
3.	Boilers: recover waste heat from blowdown	F	250-400	0.5-3.0
4.	Steam: repair/increase steam line and tank insulation; fix traps	F	100-200	1.0-15.0
5.	Increase condensate return	F	50-150	1.0-15.0
6.	Recover flash-vented steam	F	300-600	2.0-5.0
	Total (all measures not additive)		**175-225**	**16.0-18.0**
B.**	Medium-Term/Medium-Payback			
1.	Install efficient bagasse dryer (eventually using boiler flue gases)	F	350-450	5.0-20.0
2.	Install additional effect(s) on evaporator	F	400-500	4.0-7.0
3.	Install vapor recompression system	F	600-1,000	4.0-6.0
4.	Install process controls	E, F	400-500	1.0-5.0
5.	Install/increase cogeneration	E, F	500-700	--
6.	Modify batch crystallization to continuous crystallization	F	600-1,000	1.0-3.0
7.	Increase bagasse utilization by installing new boiler	F	300-500	0.0-50.0
8.	Increase power factor (when electricity is cogenerated)	E	400-500	1.0-10.0
9.	Modify operation by lengthening season (syrup storage)	F	N/A	
	Total (all measures not additive)		**600-700**	**15.0-30.0**

*E.g., housekeeping, minor equipment retrofitting.
**E.g., equipment retrofitting, process modifications.

SOURCE: Hagler, Bailly & Company.

were China and Brazil, with 22 percent and 14 percent of total LDC production, respectively.

	Pulp		Paper	
Country	Million short tons	% of LDCs*	Million short tons	% of LDCs*
China	5.19	31.6	5.35	22.1
Brazil	3.51	21.4	3.47	14.3
Mexico	0.73	4.5	1.90	7.8
Korea	0.19	1.2	1.69	7.0
Taiwan	0.28	1.7	1.48	6.1
Subtotal	9.90	60.4	13.90	57.3
Other	6.50	39.6	10.31	32.7
Total LDCs	16.40	100.0	24.2	100.0
DC	115.40		146.5	
Total world	131.80		170.7	

*All LDCs, including China, plus Czechoslovakia, Hungary, and Yugoslavia.

SOURCE: Pulp and Paper International. Annual Review, July 1982.

Processes

Papermaking involves the mechanical or chemical treatment of raw biomass, mostly wood, to produce an intermediary product, pulp. Pulp, which can be bleached or unbleached, is then mixed with other qualities of pulp, drained, dried, and calendered to produce paper or paperboard.

Pulp and paper manufacturing processes offer a much greater variety than other energy-intensive industries (i.e., steel, cement, bricks). They can be classified along two dimensions:

- The horizontal integration level
- The pulping process.

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Other subcategories in the classification include the drying process and the type of final product (e.g., writing paper, wrapping paper, paperboard, specialty papers).

Integration

Plants starting from raw wood and producing pulp only are called pulp mills or nonintegrated pulp mills. Plants starting from raw wood and producing the final product (i.e., paper or paperboard) are called integrated paper mills. Finally, plants buying pulp as their feedstock and producing the final product -- paper or paperboard -- are called nonintegrated paper mills.

Most LDCs, with the exception of China and Brazil, do not produce sufficient pulp for their needs. Consequently, they operate essentially nonintegrated paper mills.

Pulping Process

LDCs produce only 16.4 million tonnes of pulp, compared with 24.2 of paper, and rely mostly on chemical pulping, i.e., kraft, sulfite, and soda (56 percent). Mechanical pulping accounts for only 14 percent of the pulp produced, while 30 percent is made by other hybrid processes (e.g., thermomechanical).

Energy Consumption

Total LDC fuel and electricity consumption for pulp and paper making is not known, but based on average specific energy consumption, it is estimated that between 10.9 mtoe and 36.3 mtoe of purchased energy are used.* The amount of noncommercial energy used (wood, sawdust, bark, bagasse, and black liquor) is not known.

*Based on the assumption that most plants are nonintegrated, small to medium-size paper mills with a specific energy consumption ranging from 0.45 toe/ton to 1.5 toe/ton.

Specific Energy Consumption

Specific energy consumption varies widely by product, process, and country, from 0.2 toe/ton of pulp to 0.5 toe/ton of pulp, and 0.45 toe/ton to 2 toe/ton in the worst cases. The average consumption of purchased energy is around 0.7-0.8 toe/ton of paper.

Energy Conservation

As suggested by the broad range of specific energy consumption, there is considerable room for energy savings in LDCs. Typical short-term/short-payback measures and longer-term/longer-payback measures are presented below:

- Short-term/short-payback measures
  - improve boiler efficiency by reducing excess air
  - replace burners by more efficient ones
  - recover waste heat from boiler blowdown
  - increase condensate return to boiler
  - improve steam system by increasing insulation, repairing leaks, and fixing steam traps
  - increase power factor
  - recycle hot water for pulping
- Longer-term/longer-payback measures
  - install waste heat recovery devices on paper machines
  - install air preheater/economizer on boilers
  - install automatic controls on large energy-using equipment
  - improve evaporation of black liquor by installing supplemental effects, thermocompression system, or mechanical compression system
  - retrofit water demineralization plant
  - retrofit press section for higher pressure
  - produce or increase on-site power (cogeneration).

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The costs and benefits of the above measures are presented in Exhibit 7.7.

The pulp and paper industry also offers opportunities for switching from oil and gas to coal or, preferably, noncommercial fuels. Most pulp mills and integrated paper mills generate large quantities of byproducts that can be used as fuel. These include:

- Bark and sawdust (approximately 10 percent of the raw wood used)
- Bagasse dust when bagasse is used as raw material (e.g., in Peru)
- Black liquor in kraft and sulfite pulping.

While the use of coal is always technically feasible for boiler applications, it may not be practical for the lime kiln, which consumes 5-10 percent of all fuel used at the mill. The use of biomass byproducts can generally displace 10 to 15 percent of all commercial fuel used. However, capital requirements (and additional operating and maintenance costs) are substantial, generally ranging from U.S. $100,000-140,000 per tonne of steam produced per hour (low pressure) to $200,000 per ton of steam produced per hour (high pressure suitable for cogeneration). For a 1,000-tpd plant, a typical high-pressure boiler burning noncommercial fuels and sized at 100 tons of steam per hour would cost U.S. $14-20 million, with associated fuel storage and handling equipment.

Exhibit 7.7

Costs and Benefits of Selected Energy Conservation Measures

Industry: Pulp and paper

Process: Integrated mill — chemical pulping (includes kraft and sulfite pulping)

Typical range of specific primary energy consumption (SEC) in LDCs (in toe/ton): 0.25-2.0

Measure/description	Energy saved (F = fuel, E = electricity)	Specific investment cost (installed) (1982 U.S. $/toe saved)	Potential energy savings (% of SEC)
A.* Short-Term/Short-Payback			
1. Boilers: install efficient combustion controls 2. Boilers: replace burners by more efficient ones	F	200-400	1.0-5.0
3. Boilers: recover waste heat from blowdown	F	100-400	1.0-3.0
4. Steam: increase condensate return	F	200-600	1.0-5.0
5. Steam: recover vented steam (blow tank and paper machine)	F	200-400	3.0-10.0
6. Steam system: install/repair line tank insulation; steam traps	F	300-400	2.0-5.0
7. Lime kiln: install air/fuel ratio control/air preheater	F	300-500	0.5-1.0
8. Lime kiln: increase insulation thickness	F	200-600	0.5-1.0
9. Generate hot water from waste heat	F	200-500	3.0-10.0
10. Repair compressed air leaks	E	Negl.	0.5-1.0
11. Switch off equipment/lights when not necessary, and other operation measures (also improve power factors, but savings in toe are impossible to generalize)	F, E	Negl.	1.0-5.0
Total (all measures not additive)		**300-350**	**12.0-14.0**
B.** Medium-Term/Medium-Payback			
1. Install waste heat recovery devices on paper machine***	F	400-800	2.0-8.0
2. Install air preheater/economizer on boilers	F	400-800	2.0-5.0
3. Install automatic controls (digesters, bleachers, paper machines)	F, E	400-500	1.0-3.0
4. Convert batch digesters to continuous digesters	F	400-600	1.0-3.0
5. Add up effect(s) on black liquor evaporator	F	—	—
6. Increase black liquor recovery (additional boiler)	F	(400-500)	(5.0-10.0)
7. Increase use of waste fuels/convert to coal	F	500-800	N/A
8. Install backpressure steam turbine cogeneration	E	400-1,000	5.0-20.0
9. Replace water demineralization plant by a more effective one	E, F	—	1.0-2.0
10. Replace press section by a more efficient one (higher pressure)	F	—	3.0-6.0
Total (all measures not additive)		**500-600**	**10.0-15.0**

*E.g., housekeeping, minor equipment retrofitting.
**E.g., equipment retrofitting, process modifications.
***Feasible only on closed hoods.

SOURCE: Hagler, Bailly & Company.

SESSION 8: INTRODUCTION TO ENERGY AUDITING IN INDUSTRIAL PLANTS

The industrial plant energy audit is the most important element of any energy conservation and management program. The purpose of the energy audit is primarily to determine where energy waste occurs and to develop strategies for elimination of that waste.

However, the audit is not the only step taken in an energy conservation program. To be effective, such a program must also involve plant and corporate technical and management personnel at all levels and indicate a corporate commitment to the reduction of energy waste on a continuing basis.

In this session, we will place the auditing activities in the overall framework and organization of a typical energy management program as well as describing the steps taken in an energy audit program. Finally, basic requirements for implementing a successful energy management program will be presented.

Establishing an energy conservation and management program indicates a commitment to achieving certain goals. To achieve these goals, basic management techniques -- the same used to solve any management program -- are brought into play. These management techniques include:

- Planning and organizing
- Information gathering
- Decision-making
- Implementation of action plan
- Verification of plan success.

All of these techniques depend on information provided by the energy audit process. The energy audit is a study that determines how well energy resources are used and provides management with the information needed to develop strategies for controlling energy waste. The energy audit:

- Identifies areas of high energy use
- Identifies areas where energy waste occurs

- Allows energy waste reduction priorities to be developed
- Provides an index from which improvements may be measured.

An energy management program should be organized in a logical sequence. One such organization is presented in Exhibit 8.1. As shown, the energy audit is at the center of the energy management program.

Completion of a successful audit requires following a procedure that has proved successful in the energy audit process. This step-by-step process is described in this session. Within the energy audit process are two separate but consecutive activities:

- Preliminary Energy Audit
- Detailed Energy Audit.

These activities are the key elements of the procedure, and the activities are discussed below.

PRELIMINARY ENERGY AUDIT

The Preliminary Energy Audit (PEA) is essentially a preliminary data gathering and analysis effort. It uses only available data and is completed without sophisticated instrumentation. The PEA is conducted in a very short time frame (i.e., within a few days), during which the energy auditor relies on his experience to gather all relevant written, oral, or visual information that can lead to a quick diagnosis of the plant's energy situation. The PEA permits the identification of obvious sources of energy waste. Examples of easily identified waste are missing insulation, steam and compressed air leaks, inoperative instrumentation, and equipment operating unnecessarily. The typical output of a PEA is a set of recommendations on immediate low-cost actions that can be taken, and usually a recommendation for a more extensive plant energy analysis -- the detailed energy audit.

The PEA generally has five steps, as shown in Exhibit 8.2. The PEA outline presented assumes that the energy auditor has no prior knowledge of the structure of the facility to be audited and has no details of any energy management program that may exist.

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Exhibit 8.1

Steps in an Energy Conservation Program

1. **Appoint energy coordinator**

2. **Define scope and objectives of program**

3. **Conduct preliminary energy audit**
   - Organize resources
   - Collect energy consumption data
   - Analyze data
   - Develop action plan for detailed energy audit

4. **Conduct detailed energy audit**
   - Collect energy performance data
   - Analyze data
   - Determine potential for conservation
   - Develop action plan for implementation

5. **Implement strategies**

6. **Monitor savings achieved**

Exhibit 8.2

Steps in a Preliminary Energy Audit

1. **Organize resources**

   - Manpower/time frame
   - Instrumentation

2. **Identify data requirements**

   - Data forms

3. **Collect data**

   a. Conduct informal interviews

      - senior management
      - energy manager/coordinator
      - plant engineer
      - operations and production management and personnel
      - administrative personnel

   b. Conduct plant walkthrough/visual inspection

      - material/energy flow through plant
      - major functional departments
      - installed instrumentation, including utility meters
      - energy report procedures
      - production and operational reporting procedures
      - conservation opportunities

4. **Analyze data**

   a. Develop data base

      - historical data for all energy suppliers
      - time frame basis
      - other related data
      - process flow sheets
      - energy-consuming equipment inventory

   b. Evaluate data

      - energy use -- consumption, cost, and schedules
      - energy consumption indices
      - plant operations
      - energy savings potential
      - plant energy management program

Exhibit 8.2 (continued)

Steps in a Preliminary Energy Audit

5. Develop action plan

- Conservation opportunities for immediate implementation
- Projects for further study
- Resources for detailed energy audit
  - systems for testing
  - instrumentation -- portable and fixed
  - manpower requirements
  - time frame
- Refinement of corporate energy management program

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DETAILED ENERGY AUDIT

The Detailed Energy Audit (DEA), which must always be conducted **after** a PEA, is an instrumented survey followed by a detailed plant energy analysis. Sophisticated instrumentation, including flow meters, psychrometers, flue gas analyzers, and infrared scanners, is used to enable the energy auditor to compute energy efficiences and balances during typical equipment operation. The actual tests performed and the instruments required depend on the type of facility under study and the objective, scope, and level of funding of the energy management program. Thus, a detailed energy audit can take as little as 1 man-week in a light manufacturing building or as much as several man-years in a sophisticated plant such as a petrochemical complex, where expected savings justify such an effort. A typical detailed energy audit in a plant using 1,000 to 5,000 TOE annually is likely to require and justify an audit period of 1 to 6 man-weeks. Types of tests conducted during an energy audit include combustion efficiency tests and measurement of temperatures and air flows of major fuel-using equipment, determination of power factor degradation caused by various pieces of electrical equipment, and testing of process systems for operation within specification.

The energy auditor needs to check and validate his test results by using preliminary computation and existing support materials (tables, charts, manual computers). He uses the results to build energy balances, first for each major piece of equipment tested and then for the plant as a whole. From such balances, he can determine how efficiently each piece of equipment is actually operating and whether there is room for savings. Next, he analyzes the data, concentrating on identifying costs and benefits of selected options (actions, investments) for each opportunity. In some cases, the energy auditor will be unable to recommend a specific investment because of its magnitude or associated risk. In such cases, the auditor will recommend specific feasibility studies (e.g., boiler replacement, furnace modification, steam system replacement). The energy audit process stops at this point; its final output is a detailed report presenting the auditor's recommendations, together with their associated costs, benefits, and implementation characteristics (e.g., timing, impact on production).

STEPS IN A DETAILED ENERGY AUDIT PROGRAM

The major steps of a DEA program are shown in Exhibit 8.3. The audit program is designed to increase energy efficiency and reduce energy-related costs without adversely affecting a facility's ability to produce quality products.

Although sophisticated instruments are used to collect data, energy auditing is **not** an exact science. The energy auditor must also use his knowledge and judgment in collecting and interpreting data on energy use.

Step 1: Review Energy Management Program to Date

The first step is to review the existing energy management program, if any, with senior corporate staff. The energy auditor can then decide what changes may be needed in the scope of the proposed energy audit.

Step 2: Conduct Preliminary Energy Audit

If a preliminary energy audit (PEA) has not been previously done, it should be done after the review.

Step 3: Develop Action Plan, Including Detailed Energy Audit

On the basis of the review and the PEA, the energy auditor should develop an action plan, including a detailed energy audit. The action plan should take account of:

- The management of energy-related matters within the facility
- Monitoring and reporting considerations
- Relationships with manufacturers' representatives
- The availability of resources for implementing the action plan
  - money
  - personnel (in-house and external).

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Exhibit 8.3

Major Steps in Implementing Detailed Energy Audit Program

Step 1: **Review energy management program to date**

Step 2: **Conduct preliminary energy audit**

Step 3: **Develop action plan, including detailed energy audit**

Step 4: **Select scope of detailed energy audit**

- Manpower
- Testing procedures
- Instruments
- Costs

Step 5: **Complete preparatory work**

- Instrumentation repair/purchase
- Install test points
- Time frame

Step 6: **Carry out detailed energy audit field work**

- Conduct selected tests
- Collect data

Step 7: **Evaluate collected data**

Step 8: **Identify conservation opportunities**

- Operation and maintenance changes
- Capital-intensive measures

Step 9: **Develop action plan for implementation**

- Timetable
- Feasibility studies

Step 10: **Continue to monitor energy use**

Step 11: **Refine overall energy management program**

Step 4: Select Scope of Detailed Energy Audit

The next step is to determine the scope of the detailed energy audit. This step is necessary to finalize resource requirements in four areas:

- Manpower
- Testing procedures
- Instruments
- Costs.

Manpower should be selected on the basis of a review of internal and external sources. Several agencies throughout the world have standard **testing procedures** for evaluating equipment performance, and the energy auditor may want to use these procedures as a guide. For example, the U.S. Association of Mechanical Engineers provides methods for testing steam generating plant and other mechanical equipment. British standards are laid down for testing many industrial process plants.

Instrument needs will be dictated by the extent of information needed, the testing procedures used, the equipment to be tested, and the location of proposed measuring positions. The auditor must often compromise on the number and accuracy of the instruments at his disposition because of lack of funds. Typical instruments for energy auditing are listed in Exhibit 8.4. Exhibit 8.5 contains a list of U.S. suppliers of instruments.

The cost of the audit should be estimated. The cost will depend on the use of internal or external staff, the time required to complete the audit, and the sophistication of the instrumentation used. Typically, an energy audit by outside consultants in the United States costs between $20,000 and $40,000 for a plant with an energy bill of $1-$2 million.

Step 5: Complete Preparatory Work

The next step is to complete all preparatory work. All instruments to be used should be serviced and/or repaired, additional instruments purchased, and all test measuring positions and connections completed.

Exhibit 8.4

Detailed Energy Audit Instrument Kits

Instrument	Number required
Tape measure - 30 meters	1
5 meters	1
Flashlight	3
Stopwatch/chronometer	1
Pedometer	1
Gas analyzer, chemical	1
Spare parts for above	2
Gas analyzer, chemical (Includes tubes)	1
Smoke test kit	1
Temperature indicator	1
(Probes for above) - Immersion	1
300 mm	1
600 mm	1
surface probe	1
Manometers - 0-75 mm	1
0-350 mm	1
0-1200 mm	1
Velometer and probes	1
Psychrometer - electric	1
Psychrometer - mercury-in-glass	4
Spare thermometers	4
Total dissolved solids meter	1
Clamp-on ammeter	1
Watt meter	1
Power factor meter	1
Light meter	1
Stethoscope	1
Infrared pyrometer	1

Plus: assorted tubing and hand tools.

Exhibit 3.5

U.S. Suppliers of Portable Industrial Instrumentation

The following list is by no means comprehensive, but indicates some available suppliers of industrial instrumentation in the United States. The United States itself is not the only supplier of instrumentation, and equipment may be available from other countries. The prices shown are best estimates for purchase in the United States. Some equipment may not be available locally. We do not endorse any instrumentation supplier and do not accept any responsibility for any problems with any instrumentation that may be purchased from any of the listed suppliers.

Type	Supplier	F.O.B. price (U.S. dollars)
Flue gas analyzers		
Chemical CO_2, O_2 concentration combustion test kit, including smoke gun	Bacharach Instruments 301 Alpha Drive Pittsburgh, PA 15238 Telephone: (412) 782-3500 Telex: 866407	300
Electrochemical digital Fyrizer Model 10	Bacharach Instruments 301 Alpha Drive Pittsburgh, PA 15238 Telephone: (412) 782-3500 Telex: 866407	2,500
Electrochemical fuel efficiency monitor	Neotronics N.A. Inc. P.O. Box 370 411 Bradford Street, NW Gainsville, GA 30503 Telephone: (404) 535-0600	1,470
Temperature measurement		
Digital temperature indicator Model 9300	Tesoterm, Inc. P.O. Box 111509 Nashville, TN 37211-1509 Telephone: (615) 834-5082 Telex: 55-5112	200
Probes for above	Tesoterm, Inc. P.O. Box 111509 Nashville, TN 37211-1509 Telephone: (615) 834-5082 Telex: 55-5112	60-100

Exhibit 8.5 (continued)

U.S. Suppliers of Portable Industrial Instrumentation

Type	Supplier	F.O.B. price (U.S. dollars)
Temperature measurement (continued)		
Digital temperature indicator -- Digital Series 450	Omega Engineering Inc. One Omega Drive Box 4047 Stamford, CT 06907 Telephone: (203) 359-7700 Telex: 996404	275
Probes for above	Omega Engineering Inc. One Omega Drive Box 4047 Stamford, CT 06907 Telephone: (203) 359-7700 Telex: 996404	75-150
Infrared pyrometer -- Model 80 HT-3CPH (1,100°C-1,750°C)	Mikron Instrument Company Inc. P.O. Box 211 Ridgewood, NJ 07451 Telephone: (201) 891-7330	1,700
Infrared pyrometer -- Model 80 DHS - 19XC (600°C-1,700°C)	W. Wahl, Export Manager Wahl International Ltd. 5750 Hannum Avenue Culver City, CA 90230 Telephone: (213) 641-6931 Telex: 66-4406	2,250
Infrared pyrometer -- Model 80 OS-2000A (-30°C-1,400°C)	Omega Engineering Inc. One Omega Drive P.O. Box 4047 Stamford, CT 06907 Telephone: (203) 359-7700 Telex: 996404	1,900
Infrared pyrometer -- Model 8500 (0°C-700°C)	Tesoterm, Inc. P.O. Box 111509 Nashville, TN 37211-1509 Telephone: (615) 834-5082 Telex: 55-5112	1,125

Exhibit 8.5 (continued)

U.S. Suppliers of Portable Industrial Instrumentation

Type	Supplier	F.O.B. price (U.S. dollars)
Humidity measurement		
Electronic psychrometer Model 6400	Tesoterm, Inc. P.O. Box 111509 Nashville, TN 37211-1509 Telephone: (615) 834-5082 Telex: 55-5112	675
Mechanical psychrometer	Vista Scientific Corporation 85 Industrial Drive Northampton Industrial Park Ivyland, PA 18974 Telephone: (215) 322-2255	125
Air/gas flow measurement		
Alnor velometers, Series 6000P	Alnor Instruments Company 7301 North Caldwell Avenue Niles, IL 60648 Telephone: (312) 647-7866 Telex: 72-4458	800
Hot wire anemometer	Alnor Instruments Company 7301 North Caldwell Avenue Niles, IL 60648 Telephone: (312) 647-7866 Telex: 72-4458	1,000
Pitot tube and manometer, Series 400	Dwyer Instruments Inc. P.O. Box 373 Michigan City, IN 46360 Telephone: (219) 872-9141	300
Draft measurement		
"U" tube manometers	Dwyer Instruments Inc. P.O. Box 373 Michigan City, IN 46360 Telephone: (219) 872-9141	25-100
TDS meter -- conductivity meter	John J. Berg, Export Manager Myron L. Company 6231C Yarrow Drive Carlsbad, CA 92008-4893 Telephone: (619) 438-2021 Telex: 695009	150

Exhibit 8.5 (continued)

U.S. Suppliers of Portable Industrial Instrumentation

Type	Supplier	F.O.B. price (U.S. dollars)
Electrical measurement		
Clamp-on ammeter	Epic, Inc. 150 Nassau Street New York, NY 10038 Telephone: (212) 349-2470	285
Clamp-on power factor meter	Epic, Inc. 150 Nassau Street New York, NY 10038 Telephone: (212) 349-2470	450
Clamp-on wattmeter	Epic, Inc. 150 Nassau Street New York, NY 10038 Telephone: (212) 349-2470	450
Clamp-on ammeter, Model 1000	T.I.F. Instruments, Inc. 3661 NW 74th Street Miami, FL 33147 Telephone: (305) 696-7100 Telex: 512302	175
Clamp-on wattmeter, Model 2000	T.I.F. Instruments, Inc. 3661 NW 74th Street Miami, FL 33147 Telephone: (305) 696-7100 Telex: 512302	400
Clamp-on power factor meter, Model 1000	T.I.F. Instruments, Inc. 3661 NW 74th Street Miami, FL 33147 Telephone: (305) 696-7100 Telex: 512302	400
Light meter	Simpson Electric Company 853 Dundee Avenue Elgin, IL 60120 Telephone: (312) 697-2260 Telex: 72-2416	350

The energy auditor should make sure that the time frame selected for the audit does not conflict with the operation of the equipment to be tested or the plant in general. The chosen testing date should also be representative of normal plant operation.

Step 6: Carry Out Detailed Energy Audit Field Work

The field work consists of two main tasks. The first task is to perform the following tests on selected equipment to evaluate its efficiency:

- Combustion efficiency tests of boilers and other direct-fired equipment
- Measurement of temperatures and air flows in equipment such as kilns, dryers, and air handling units
- Examination of steam distribution systems for failed steam traps
- Verification of proper flow rates in fluid handling systems to determine pump performance
- Determination of power factor degradation caused by various pieces of electrical equipment
- Testing of process systems for operation within specification.

The second task is to gather data enabling the energy auditor to evaluate all energy aspects within a facility. The energy auditor should use the PEA as a starting point, expanding on it to fill data gaps and to learn more about the operation of the plant. He should conduct interviews with selected personnel, examine records, observe operations, and monitor and check conditions. In this step, the energy auditor will often gather data, review them, gather data again, and review them again.

Step 7: Evaluate Collected Data

There are several areas in which energy data can be evaluated, such as energy purchasing and energy use. However, the main purpose and function of the analysis will be to evaluate energy conservation opportunities by following the steps presented in Exhibit 8.6.

Exhibit 8.6

Evaluation of Energy Conservation Opportunities

1. **Evaluate existing operating conditions**

   - Hours of operation
   - Method of operation
   - Energy requirements
   - Initial product specification
   - Final product specification under existing conditions

2. **Identify alternative operation conditions**

   - Hours of operation
   - Method of operation
   - Energy requirements
   - Final product specification under alternative operating conditions

3. **Calculate energy consumption under alternative operation conditions**

4. **Determine feasibility of alternative operation conditions**

   - Product quality
   - Cost

5. **Estimate savings from switching to alternative operation conditions**

   - Difference in energy consumption
   - Energy cost savings

6. **Next steps to implement alternative condition operations**

   - Capital needs
   - Feasibility studies

7. **Implement**

Step 8: Identify Conservation Opportunities

The results of the evaluation step can be used to identify two types of conservation opportunities:

- Operation and maintenance (O&M) changes
- Capital-intensive measures.

O&M opportunities are those that require little or no major capital investment and have rapid returns on investment. On a simple payback basis, O&M changes have paybacks of 1 year or less. They are sometimes called no-cost/low-cost or housekeeping measures.

Capital-intensive measures require large capital investments (typically in excess of $25,000). Simple payback periods are usually more than 1 year. The energy auditor should use payback periods as a guideline when making his list of recommendations. He should also identify the company's attitude on capital-intensive projects as part of his detailed energy audit activities.

Step 9: Develop Action Plan for Implementation

The energy auditor will probably not have the authority to implement the measures identified, especially if capital requirements are large. Instead, he will complete a report for corporate decision-makers. The report, which will present the findings of his audit, should include an action plan.

The action plan should contain a timetable for implementation. It should be possible to implement O&M changes immediately. However, major capital-intensive measures may require feasibility studies before a decision can be made to implement them. The energy auditor should indicate the overall time frame to give decision-makers an idea of when energy cost savings will begin to show positive cash flow.

An action plan often includes a recommendation for a self-financing program. In a self-financing program, O&M changes are implemented, and the resulting cost savings are invested directly in lower-cost capital-intensive measures to bring even more savings. Eventually, cost savings are available to pay for the most costly capital-intensive measures.

Step 10: Continue to Monitor Energy Use

Energy efficiency in a company should not begin and end with the detailed energy audit. To sustain its energy efficiency, a company must continue to monitor its energy use.

The detailed energy audit report should recommend improvements to the existing monitoring and reporting procedures for energy use. Very few, if any, companies have an adequate system of procedures in place. Without such a system, it is hard to spot changes in consumption that result from increases or decreases in efficiency.

Possible improvements that can be made to monitoring and reporting procedures include:

- Upgrading of instrumentation
- Introduction of energy reporting procedures
- Development of energy consumption indices
- Development of energy models.

Step 11: Refine Overall Energy Management Program

The major recommendations of the energy audit should be refinements to the overall corporate energy management program. Because energy affects many aspects of a company's operations, improvements in energy use will not take place without commitment at the highest levels of management. Management's perception of the state of energy use will determine the success of any energy management program. The requirements for a successful overall corporate energy management program are detailed in Exhibit 8.7.

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Exhibit 8.7

Basic Requirements for Successful Corporate Energy Management Program

- Commitment at corporate level to energy conservation
  - resources, personnel, funds
  - goals

- Optimum use of resources
  - intercompany information system
  - centralized technical support
  - facilities management training

- Identification of opportunities
  - quick-payback items
  - capital-intensive projects
  - evaluation and relationship to production

- Implementation of projects
  - self-financing program
  - capital project selection
  - specifications and bid

- Establishment of operational criteria
  - optimum production/energy targets
  - operations and maintenance procedures

- Monitoring and targeting
  - evaluation
  - reevaluation

Recommendations for changes may include:

- Appointing personnel to be responsible for energy
- Formally structuring a corporate energy management program
- Training staff and employees in energy awareness.

SUMMARY

The energy audit procedure described has proved successful worldwide, since Reliance Energy Services first developed the technique in 1966. To date, Reliance has conducted more than 4,000 energy audits for clients in all industrial sectors in developed and developing countries.

However, it should be remembered that an energy audit alone **does not** produce energy savings. Energy savings are **not** realized until the recommendations of the audit are implemented. There are many examples of successful audits that did not achieve savings because of the failure of management to take the next and vital step of implementation. Where management has made that step, energy cost reductions and subsequent increased profitability have been documented.

Also, an energy audit is not a one-time, on-off action. Industrial facilities are dynamic; thus, energy requirements today may not be the same as energy requirements in 2 or 3 years. Technological changes may take place that can lead to conservation opportunities not yet anticipated. The energy audit process should be an ongoing activity in an industrial facility in the same fashion as equipment maintenance functions.

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SESSION 9: INDUSTRIAL ENERGY AUDITING — INSTRUMENTATION

INTRODUCTION

This session covers the use of fixed and portable instruments to gather data to determine energy performance of various types of plant equipment. The session deals with the actual gathering of data only; Session 10 covers the data analysis step.

In Session 8, two different types of energy surveys were defined. These were the preliminary energy audit and the detailed energy audit. It is only in the detailed energy audit that sophisticated instrumentation, such as those about to be described, is used.

The types of test instrumentation introduced and described in this session are used for:

- Temperature measurements
- Electrical measurements
- Flow measurements
- Combustion efficiency measurements
- Light level measurements.

Each of the above categories are discussed below.

TEMPERATURE MEASUREMENT

Probably the most important category of instruments used in the conduct of a detailed energy audit is instruments for temperature measurements. There are many types available for use in different temperature ranges, varying accuracy, speed of response, cost, and maintenance requirements. Three types of instruments are discussed in more detail below:

- Thermometers and thermocouples
- Pyrometers
- Psychrometers.

Thermometers and Thermocouples

The simplest type of temperature measuring device is the **liquid-in-glass thermometer.** A liquid is enclosed in a sealed glass capillary tube. Temperature is sensed by measuring the volume change of the incompressible liquid that accompanies any temperature change. The most common is the mercury-in-glass thermometer (see Exhibit 9.1). These thermometers are generally usable over the temperature range -35°C to 650°C with an accuracy of plus/minus 0.5°C-0.75°C over the range.

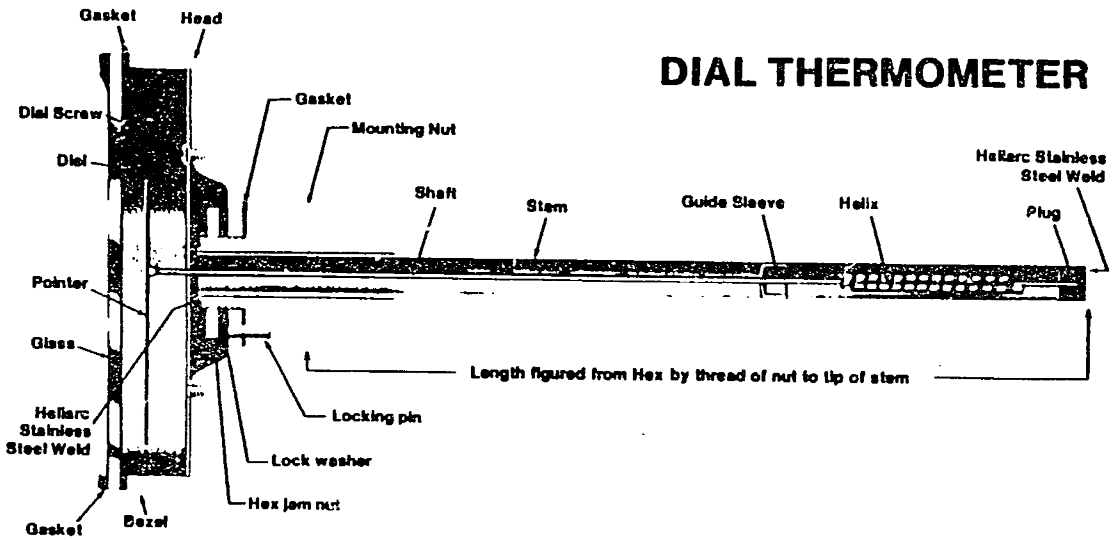
Liquid-in-glass thermometers are immersion type instruments, which means that the sensing portion of the thermometer must be in intimate contact with, or immersed in, the object under study. Mercury-in-glass thermometers are used by immersing the bulb at the bottom end in the fluid to be measured (liquid or gas). The major disadvantage is its relatively slow response time. The glass tube is also rather fragile; care should be taken when handling the thermometer.

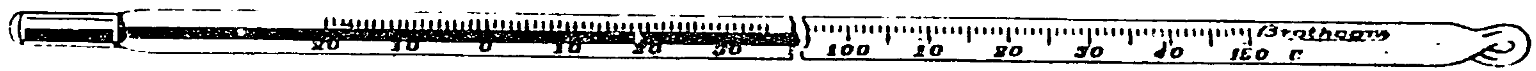
A similar type of temperature measurement device is the **dial thermometer.** The dial thermometer consists of a direct reading dial with a stem attached. The stem is sealed and contains a helix made of two layers of dissimilar metals. Changes in temperature cause the metals to expand or contract at different rates, imparting motion to the dial. These thermometers are also of the immersion type and are available in a large temperature ranges.

While these thermometers are useful for portable measurements, they can also be used for permanent installation. This involves mounting a thermometer well into a pipe or wall that contains the fluid to be measured. The thermometer well can be installed either with pipe thread connection or welded flange. Proper selection of thermometer well materials is required to afford protection from corrosive materials, high pressure, or flow.

A more sophisticated temperature measurement device is the **thermocouple.** A thermocouple consists of a pair of conductors of different metals or alloys, joined together at both ends. One end is placed in the area where temperature is to be measured. The difference in temperature between that end (the measuring junction) and the other end (the reference junction) causes a voltage to be generated. The magnitude of the

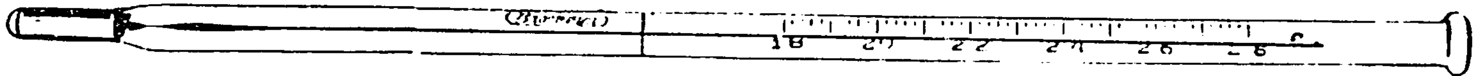
DIAL THERMOMETER





RED MERCURY MAGNIFYING Code: RM

The mercury column of code RM thermometers is magnified to approximately 1/16" across, and by internal reflection it appears as a bright red for easier reading. It is lens front tubing, somewhat triangular in cross section.



RED MERCURY ROUND Code: RR

By internal reflection the normal width mercury column appears as a bright red for easier reading. The tubing is round in cross section.

MICRO 4 to 5mm. O.D. Code: O

The thin 4 to 5mm. diameter and small sensitive mercury bulbs of Micro thermometers make them ideal for small sample distillations or where space is limited. They fit 3/16" stopper holes and the scale starts unobscured above the stopper. The thin diameter permits use of other tubes alongside. Micro thermometers are made shorter than Standard to reduce fragility.

MERCURY-IN-GLASS THERMOMETER

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voltage is a function of the difference in temperatures between the measuring and the reference junctions. The thermocouple is also an immersion-type instrument.

Various combinations of metals can be used in the manufacture of thermocouples. The choice of thermocouple depends on the application (see Exhibit 9.2). Seven types have been given letter designations by the Instrument Society of America, and temperature/voltage correlations have been published and recognized by standards organizations throughout the world. The seven types are described below.

The **Type B thermocouple** consists of two platinum/rhodium conductors (one at 6 percent rhodium, the other at 30 percent rhodium); it can be used over a temperature range of 0°C to 1,820°C in an oxidizing or inert atmosphere (continuous service) and in a vacuum (short service). It produces a low voltage output and cannot be used in a reducing atmosphere (hydrogen or carbon monoxide) or in the presence of metallic or non-metallic vapors; it cannot be used with a metallic protection tube or in a thermometer well.

The **Type R thermocouple** consists of platinum and platinum/rhodium (13 percent) conductors and can be used over a temperature range of -50°C to 1,768°C. In other respects, it is similar in application to the Type B thermocouple; its chief advantage over the Type B thermocouple is its higher voltage output.

The **Type S thermocouple** consists of platinum and platinum/rhodium (10 percent) conductors. It can be used over the same range as the Type R and is similar in application to the Type B and Type R thermocouples. This type is the original thermocouple, and is the standard for measuring temperature between the melting points of antimony and gold (630°C to 1,064°C).

The **Type J thermocouple** consists of an iron conductor coupled to a conductor made of an alloy of 55 percent copper and 45 percent nickel. Its effective temperature range is -210°C to 760°C; above 540°C, the iron wire tends to oxidize and heavy gauge wire is required. This thermocouple type is satisfactory for continuous use in oxidizing, reducing, or inert atmospheres, but should not be used in high-temperature sulfurous atmospheres. These thermocouples are very commonly used chiefly because of their relatively low cost.

Exhibit 9.2

Standard Thermocouple Application Chart

Thermocouple type	Temperature range	Atmosphere* R	O	I	V	Millivolt output
B	0°C to 1,820°C 32°F to 3,310°F		X	X	X	0 to 13.814
R	-50°C to 1,768°C -60°F to 3,210°F		X	X		-0.226 to 21.108
S	-50°C to 1,768°C -60°F to 3,210°F		X	X		-0.236 to 18.698
J	-210°C to 760°C -350°F to 1,400°F	X	X	X	X	-8.096 to 42.922
K	-270°C to 1,372°C		X	X		-6.458 to 54.875
T	-270°C to 400°C -450°F to 750°F	X	X	X	X	-6.258 to 20.869
E	-270°C to 1,000°C -450°F to 1,830°F		X	X		-9.835 to 76.358

*R = reducing
O = oxidizing
I = inert
V = vacuum.

The **Type K thermocouple** is also known as a Chromel/Alumel thermocouple. Chromel is an alloy of 10 percent chromium and 90 percent nickel; Alumel is an alloy of 95 percent nickel plus aluminum, silicon, and manganese. They can be used over a range of -270°C to 1,372°C in oxidizing and inert atmospheres; they are not suitable for use in reducing atmospheres. This is the most popular thermocouple used in industry.

The **Type T thermocouple** is of copper and constantan construction and is usable over a temperature range of -270°C to 400°C, which limits its industrial uses. It can be used in continuous service in a vacuum or in oxidizing, reducing, or inert atmospheres.

Finally, the **Type E**, or Chromel/constantan thermocouple, is effective over a range of -270°C to 1,000°C and has the highest voltage output of any standard type of thermocouple. It can be used in oxidizing and inert atmospheres.

Thermocouples are available in a variety of configurations and designs for a large number of applications. Thermocouple probes (consisting of the thermocouple sheathed in a protective metal case and a handle) are available in various lengths and shapes.

The thermocouple itself must be used with a device that converts the voltage produced into a measure of temperature. A simple voltmeter can be used in conjunction with calibration curves for a particular thermocouple, but this is an unwieldy procedure since the reference junction temperature must be known. Special thermocouple thermometers are available that provide direct digital readout of measured temperature (see Exhibit 9.3). These devices automatically compensate for reference junction temperature.

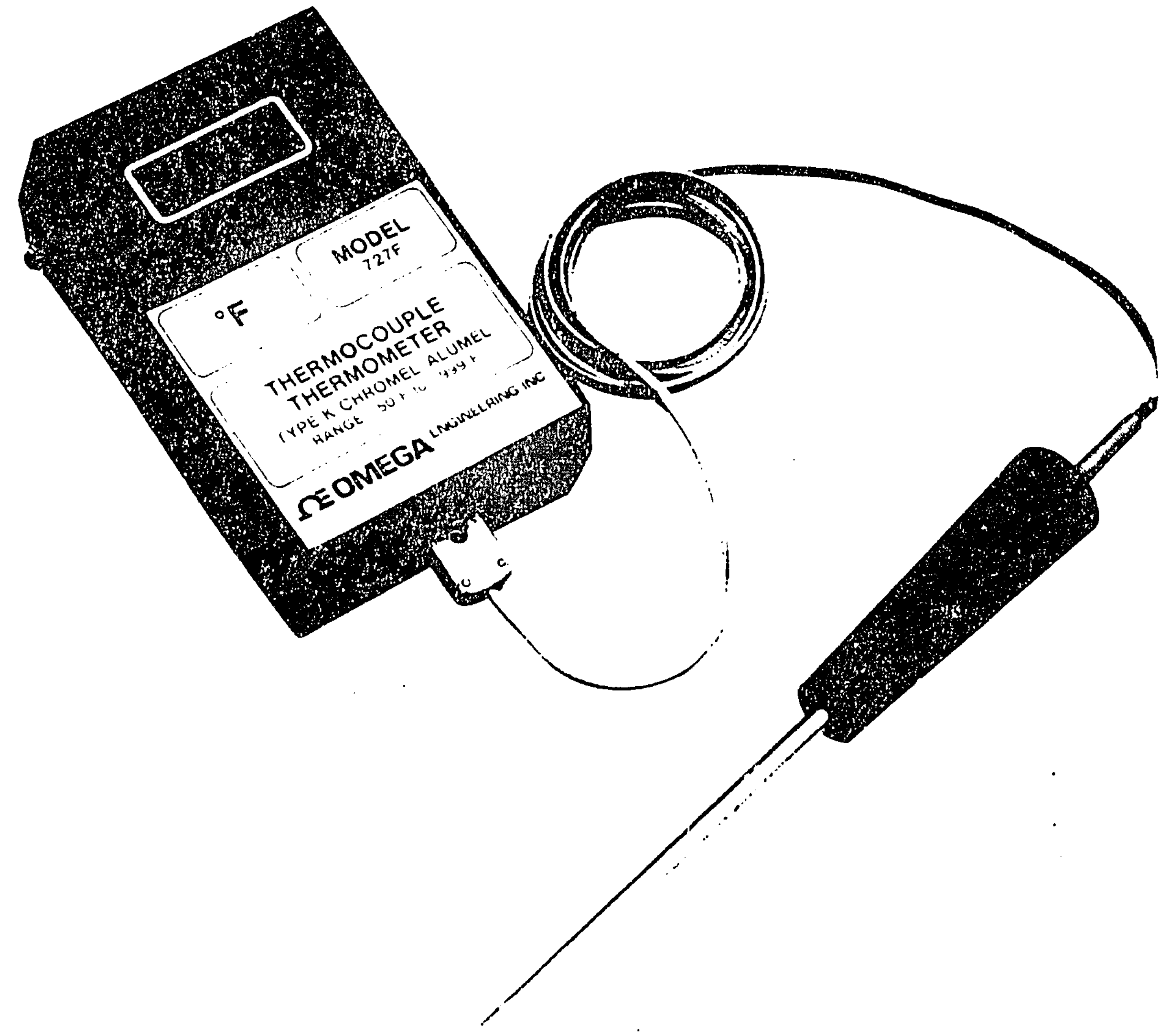
Pyrometers

The liquid-in-glass and thermocouple temperature measurement systems described in the previous section depend on being in contact with the object whose temperature is to be measured. Another type of temperature measurement instrument does not require physical contact; these are thermal **radiation sensors** or **pyrometers.**

Thermal radiation is a part of the electromagnetic spectrum that includes infrared and part of the visible light range. Visible light range extends from wavelengths of about

Exhibit 9.3

THERMOCOUPLE AND MATCHED THERMOMETER



0.4 to 0.75 microns; the infrared band extends from 0.75 to 1,000 microns. For a given wavelength, the intensity of thermal radiation emitted increases with temperature.

A perfectly radiating material is known as a "black-body." It is a surface that absorbs all radiant energy that falls on it and radiates the maximum thermal energy possible for a particular temperature. There is no "perfect" black-body; it is a concept. Real bodies do not absorb all the energy falling on them and do not radiate the maximum thermal energy possible. The ratio of the thermal energy radiated by the object to be measured to that expected by a black-body is called the emissivity. The value of emissivity can range between 0 and 1 and, in practice, is always less than 1. Emissivity depends on the finish of the surface being measured, and on the material of which it is made.

Because emissivity is less than 1, a radiation pyrometer will receive less than the maximum radiation that could be radiated by the surface being measured. To compensate, the pyrometer has an emissivity control to account for this. To achieve accurate temperature measurements, the emissivity of the surface to be measured must be known. In Exhibit 9.4, emissivity values for a variety of materials are presented.

It is possible to "fix" the emissivity of an object whose temperature is to be measured. Manufacturers of radiation pyrometers offer paints that can be applied to the object under study. The paint provides a dull black finish of known emissivity, and is most useful for measurement of fixed or moving bodies.

There are four types of radiation pyrometers:

- Broadband pyrometer
- Optical pyrometer
- Bandpass pyrometer
- Ratio pyrometer.

The broadband and optical pyrometers are the most common pyrometers and are discussed in more detail than the bandpass and ratio pyrometers. Each type is discussed in the following paragraphs.

These tables are presented for use as a guide when making infrared temperature measurements with the OMEGASCOPE™ or other infrared pyrometers. The total emissivity (Є) for Metals, Non-metals and Common Building Materials are given.

Since the emissivity of a meterial will vary as a function of temperature and surface finish, the values in these tables should be used only as a guide when making relative or delta measurements.

The exact emissivity of a material should be determined when absolute measurements are required.

Exhibit 9.4

MATERIAL	TEMPERATURE (°F)	Є - EMISSIVITY
Alloys		
20-Ni, 24-CR, 55-FE, Oxidized	392	.90
" " " "	932	.97
60-Ni, 12-CR, 28-FE, Oxidized	518	.89
" " " "	1040	.82
80-Ni, 20-CR, Oxidized	212	.87
" " "	1112	.87
" " "	2372	.89
Aluminum		
Unoxidized	77	.02
"	212	.03
"	932	.06
Oxidized	390	.11
"	1110	.19
Oxidized at 1110°F	390	.11
" " "	1110	.19
Heavily Oxidized	200	.20
" "	340	.31
Highly Polished	212	.09
Roughly "	212	.18
Commercial Sheet	212	.09
Highly Polished Plate	440	.04
" " "	1070	.06
Bright Rolled Plate	338	.04
" " "	932	.05
Alloy A3003, Oxidized	600	.40
" " "	900	.40
Alloy 1100-0	200-800	.05
Alloy 24ST	75	.09
" " Polished	75	.09
Alloy 75ST	75	.11
" " Polished	75	.08
Bismuth, Bright	176	.34
" Unoxidized	77	.05
" "	212	.06
Brass		
73% Cu, 27% Zn, Polished	476	.03
" " "	674	.03
62% Cu, 37% Zn, Polished	494	.03
" " "	710	.04
83% Cu, 17% Zn, Polished	530	.03
Matte	68	.07
Burnished to Brown Color	68	.40
Cu-Zn, Brass Oxidized	392	.61
" " "	752	.60
" " "	1112	.61
Unoxidized	77	.04
"	212	.04
Cadmium	77	.02
Carbon		
Lampblack	77	.95
Unoxidized	77	.81
"	212	.81
"	932	.79
Candle Soot	250.95,	
Filament	500	.95
Graphitized	212	.76
"	572	.75
"	932	.71
Chromium	100	.08
"	1000	.26
" Polished	302	.06
Cobalt, Unoxidized	932	.13
" "	1832	.23
Columbium, Unoxidized	1500	.19
" "	2000	.24
Copper		
Cuprous Oxide	100	.87
" "	500	.83
" "	1000	.77
Black, Oxidized	100	.78
Etched	100	.09
Matte	100	.22

MATERIAL	TEMPERATURE (°F)	Є - EMISSIVITY
Roughly Polished	100	.07
Polished	100	.03
Highly Polished	100	.02
Rolled	100	.64
Rough	100	.74
Molten	1000	.15
"	1970	.16
"	2230	.13
Nickel Plated	100-500	.37
Dow Metal	0-600	.15
Gold		
Enamel	212	.37
Plate (.0001)		
on .0005 Silver	200-750	.11-.14
on .0005 Nickel	200-750	.07-.09
Polished	100-500	.02
"	1000-2000	.03
Haynes Alloy C, Oxidized	600-2000	.90-.96
Haynes Alloy 25, "	600-2000	.86-.89
Haynes Alloy X, "	600-2000	.85-.88
Inconel Sheet	1000	.28
" "	1200	.42
" "	1400	.58
Inconel X, Polished	75	.19
Inconel B, "	75	.21
Iron		
Oxidized	212	.74
"	930	.84
"	2190	.89
Unoxidized	212	.05
Red Rust	77	.70
Rusted	77	.65
Liquid	2760-3220	.42-.45
Cast Iron		
Oxidized	390	.64
"	1110	.78
Unoxidized	212	.21
Strong Oxidation	104	.95
" "	482	.95
Liquid	2795	.29
Wrought Iron		
Dull	77	.94
"	660	.94
Smooth	100	.35
Polished	100	.28
Lead		
Polished	100-500	.06-.08
Rough	100	.43
Oxidized	100	.43
Oxidized at 1100°F	100	.63
Gray Oxidized	100	.28
Magnesium	100-500	.07-.13
Magnesium Oxide	1880-3140	.16-.20
Mercury	32	.09
"	77	.10
"	100	.10
"	212	.12
Molybdenum	100	.06
"	500	.08
"	1000	.11
"	2000	.18
" Oxidized at 1000°F	600	.80
" " " "	700	.84
" " " "	800	.84
" " " "	900	.83
" " " "	1000	.82
Monel, Ni-Cu	392	.41
" "	752	.44
" "	1112	.46
" " Oxidized	68	.43
" " Oxidized at 1110°F	1110	.46

MATERIAL	TEMPERATURE (°F)	Є - EMISSIVITY
Nickel		
Polished	100	.05
Oxidized	100-500	.31-.46
Unoxidized	77	.05
"	212	.06
"	932	.12
"	1832	.19
Electrolytic	100	.04
"	500	.06
"	1000	.10
"	2000	.16
Nickel Oxide	1000-2000	.59-.86
Palladium Plate		
(.00005 on .0005 silver)	200-750	.16-.17
Platinum	100	.05
"	500	.05
"	1000	.10
" Black	100	.93
" "	500	.96
" "	2000	.97
" Oxidized at 1100°F	500	.07
" " " "	1000	.11
Rhodium Flash		
(.0002 on .0005 Ni)	200-700	.10-.18
Silver		
Plate (.0005 on Ni)	200-700	.06-.07
Polished	100	.01
"	500	.02
"	1000	.03
"	2000	.03
Steel		
Cold Rolled	200	.75-.85
Ground Sheet	1720-2010	.55-.61
Polished Sheet	100	.07
" "	500	.10
" "	1000	.14
Mild Steel, Polished	75	.10
" " Smooth	75	.12
" " Liquid	2910-3270	.28
Steel, Unoxidized	212	.08
" Oxidized	77	.80
Steel Alloys		
Type 301, Polished	75	.27
" " "	450	.57
" " "	1740	.55
" 303, Oxidized	600-2000	.74-.87
" 310, Rolled	1500-2100	.56-.81
" 316, Polished	75	.28
" " "	450	.57
" " "	1740	.66
" 321	200-800	.27-.32
" " Polished	300-1500	.18-.49
" " w/BK Oxide	200-800	.66-.76
" 347, Oxidized	600-2000	.87-.91
" 350	200-800	.18-.27
" " Polished	300-1800	.11-.35
" 446, Polished	300-1500	.15-.37
" 17-7PH	200-600	.44-.51
" " Polished	300-1500	.09-.16
" C1020, Oxidized	600-2000	.87-.91
" PH-15-7 MO	300-1200	.07-.19
Stellite, Polished	68	.18
Tantalum		
Unoxidized	1340	.14
"	2000	.19
"	3600	.26
"	5306	.30
Tin, Unoxidized	77	.04
" "	212	.05
Tinned Iron, Bright	76	.05
" " "	212	.08

The **broadband pyrometer** (see Exhibit 9.5) is the simplest pyrometer both in design and use. It measures radiation in all wavelengths in the visible and infrared regions, and is suitable for use in a temperature range from less than 0°C to over 3,000°C. The emissivity of the material to be measured is set on the emissivity control. The object is sighted in the same manner as a gun (some models use optical sighting instead of bead and groove sighting). The trigger is depressed, and a reading is indicated in the display. The model shown in the exhibit has a digital display; some models use a dial-type display.

An **optical pyrometer** (see Exhibit 9.6) measures by comparing the brightness of visible radiation from the object being measured to that of a reference. It operates over a narrow wavelength band and is useful in the temperature range of 600°C to over 3000°C. The optical pyrometer is slightly more complex in operation than the broadband pyrometer. The instrument depends on the ability of the human eye to discern the difference in brightness between two sources of light. As with the broadband pyrometer, the object to be measured is sighted. The adjusting control is rotated until the brightness of the object measured equals that of the reference as viewed through the eyepiece. The adjusting control is coupled to a temperature scale for direct reading. This instrument is used in high-temperature applications where the emissivity of the object being measured is close to unity. No provision is normally made for adjustment of emissivity.

A **bandpass pyrometer** operates over a selected range of wavelengths by use of special filters to eliminate undesired wavelengths. These devices are useful in measuring such materials as glass or plastic films. Since glass is not transparent to wavelengths above about 2.8 microns, the pyrometer must be sensitive only to those wavelengths to avoid measurement of the temperature of materials behind the glass.

The **ratio pyrometer** measures the intensities of radiation emitted by the object at two wavelengths, using the ratio to compute the object's temperature.

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Exhibit 9.5

BROAD BAND PYROMETER

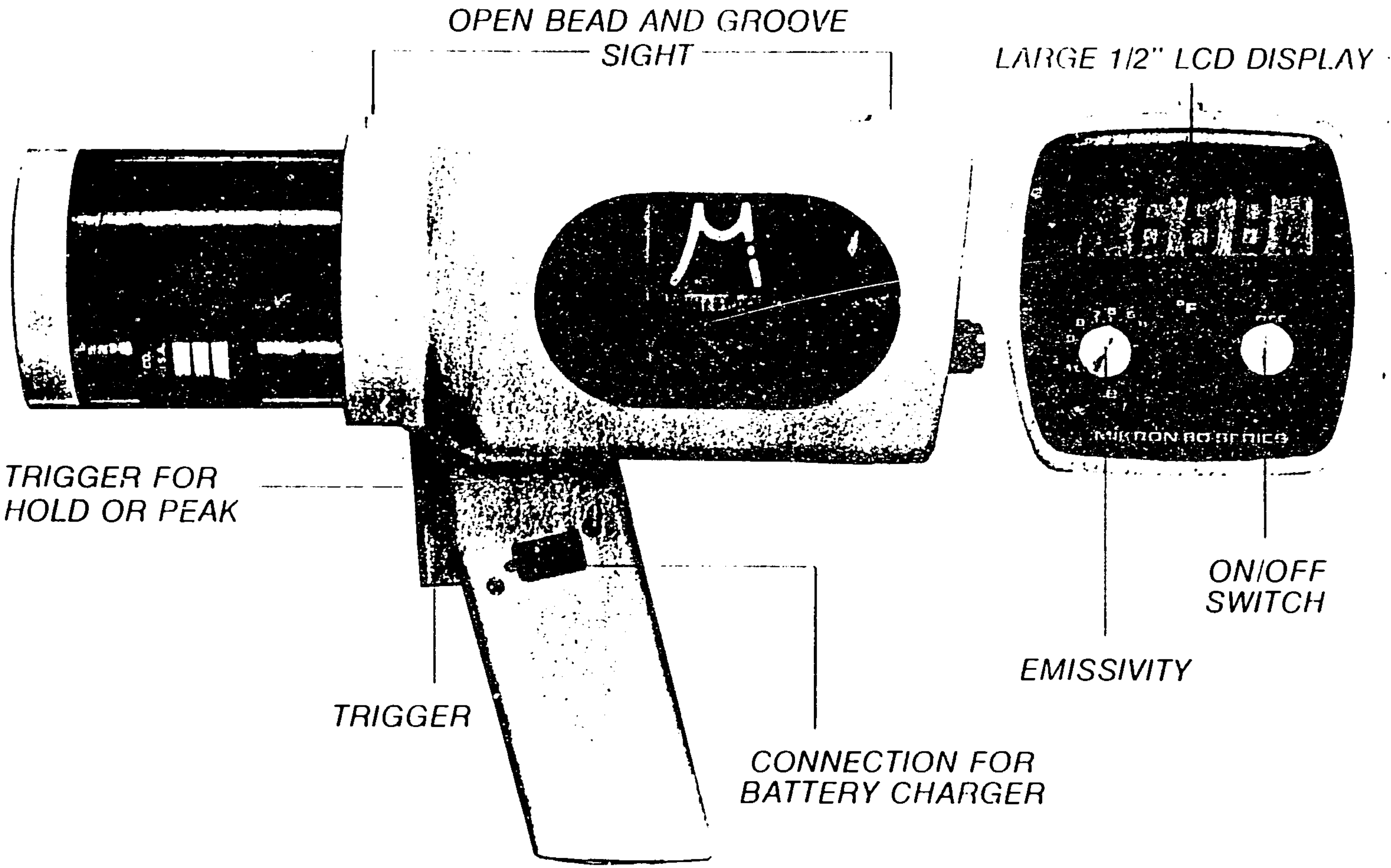

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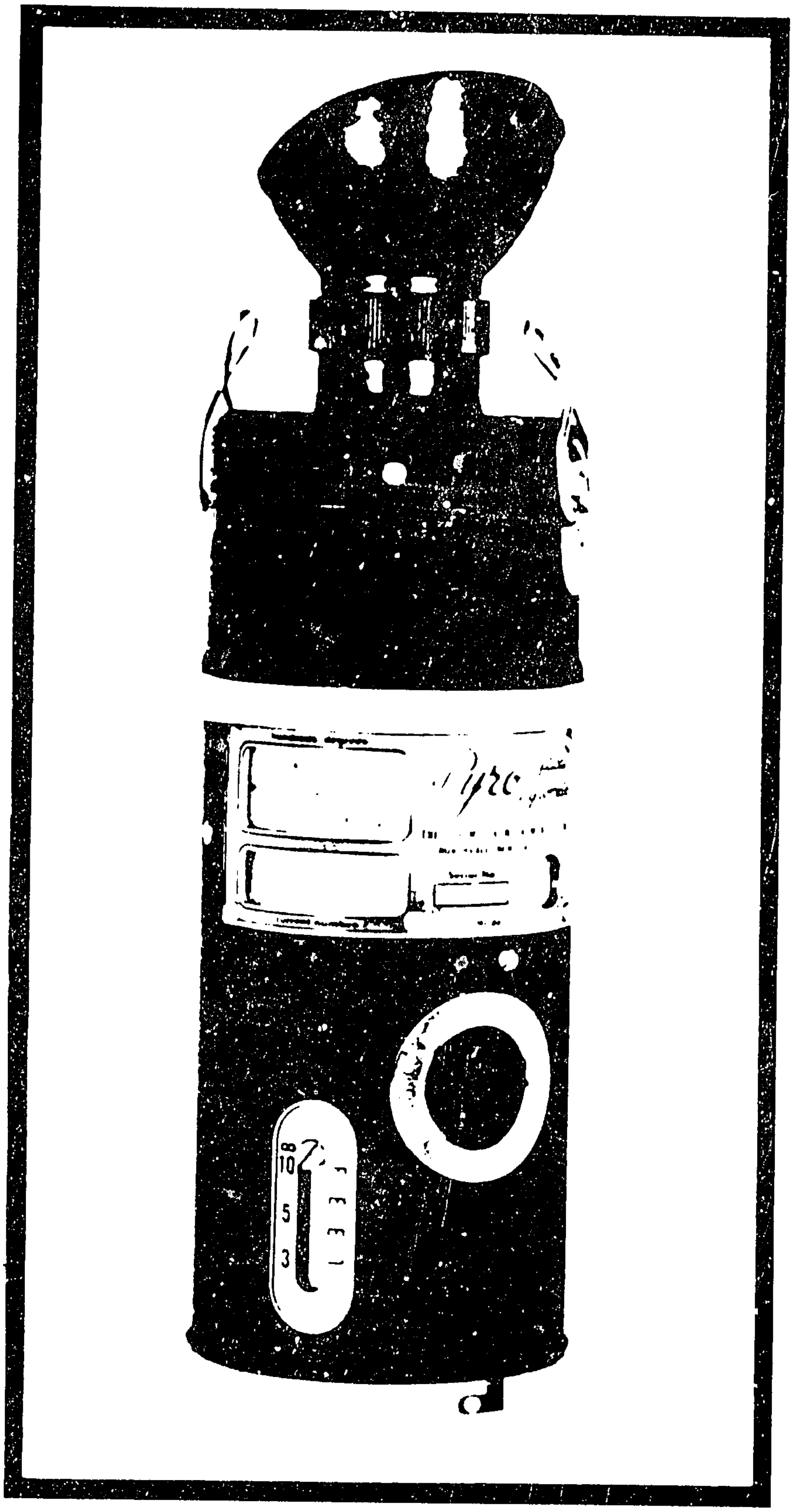
Exhibit 9.6

OPTICAL PYROMETER



Psychrometers

Psychrometers are used to measure air flow temperature. They provide information not only on the dry bulb temperature of the air flow to be measured, but indicates its wet bulb temperature, or relative humidity, as well.

Two types of psychrometers are available (see Exhibit 9.7). The first is a **mechanically-aspirated psychrometer**. This device consists of two mercury-in-glass thermometers, one of which is covered about the mercury reservoir by a wick. The wick is wetted by water and indicates wet bulb temperature. Relative humidity is determined by reference to a psychrometric chart or by use of built-in scales. Other psychrometric properties may be determined by reference to a psychrometric chart. A built-in fan pulls air over the thermometer bulbs to speed response time.

The second type of psychrometer is the **sling psychrometer**, which is twirled to provide rapid response. It is electronic in nature and yields temperature and relative humidity information directly.

Psychrometers are used by immersion of the entire psychrometer (mechanically aspirated) or probe (electronic) in the air stream to be measured. After allowing the needed measurement time to elapse, readings are taken from the instrument. Psychrometers are used to test air handling units, dryers, and combustion systems.

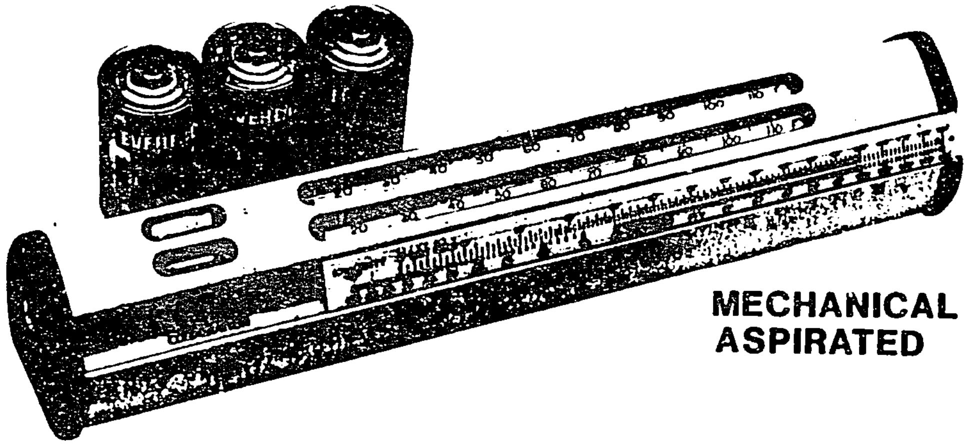
ELECTRICAL MEASUREMENT

There are four electrical measurements of particular interest in the conduct of a detailed energy audit. These are:

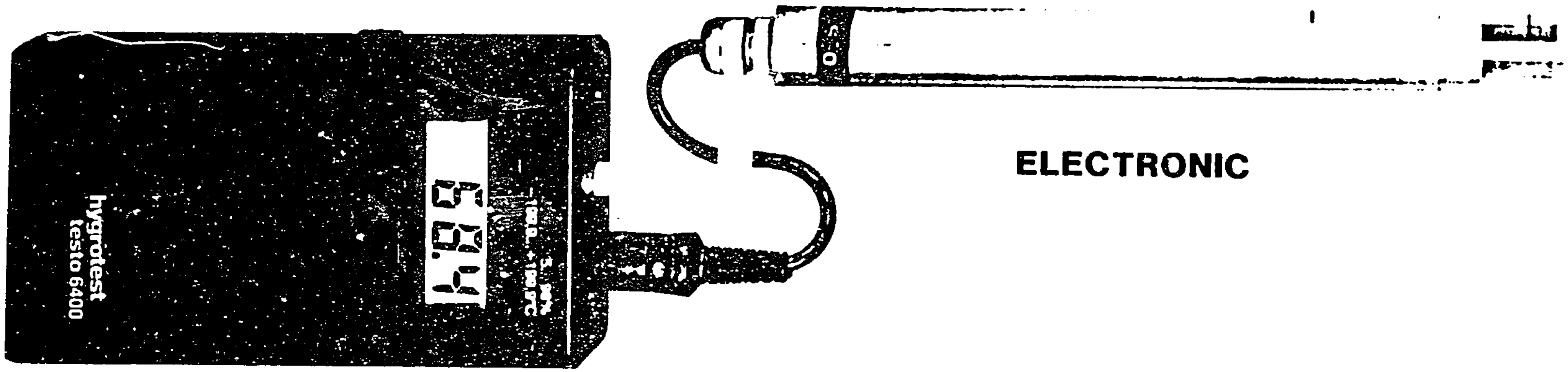
- Amperage
- Voltage
- Wattage (or instantaneous demand)
- Power factor.

Exhibit 9.7

PSYCHROMETERS



MECHANICAL ASPIRATED



ELECTRONIC

Amperage is a measure of the flow of electrons in an electric current. The current carrying capacity of the conductor is called ampacity. Standard tables are available that show, for a given conductor size and insulation system, the maximum allowable current that will not cause damage to the insulation due to heat generated.

Amperage is measured using an **ammeter.** Several types of ammeters are available. The most common used are the clamp-on type and the recording ammeter.

The **clamp-on ammeter** (see Exhibit 9.8) is a portable instrument providing direct readout of the current flowing through a conductor. The **recording ammeter** (see Exhibit 9.9) is similar in operation, but it provides a graphical presentation of amperage in a circuit over a period of time. Both ammeters consist of a current transducer (the toroid) that is connected to the display portion of the device.

A current flowing in a conductor sets up a magnetic field at right angles to the conductor. The current transducer is placed within that magnetic field, and a current is induced in it. The magnetic field strength is proportional to the current in the conductor; the induced electric current in the current transducer is proportional to the magnetic field strength. The current induced in the current transducer is measured by the ammeter; the ammeter is a calibrated device that gives the actual current in the conductor.

Both types of ammeters are easy to use. These devices may have different scales for measurement (e.g., 0-300 amps, 0-1,000 amps); the proper scale should be selected. The current transducer should be properly selected, based on the magnitude of the current to be measured. The current transducer must close around the conductor under study and be slipped over the conductor feeding the load under study to ensure proper readings. For polyphase power systems, it is sometimes useful to obtain amperage readings on all phases to determine imbalances.

Safety precautions must be observed when measuring any electrical system. Care should be taken in any attempt to use a current transducer on any bare (uninsulated) electrical conductor. Insulated gloves should always be worn.

Voltage is a measure of the force used to move electrons in an electric current, and is generally constant. While voltage is not of primary importance in the conduct of

Exhibit 9.8

CLAMP ON AMMETER

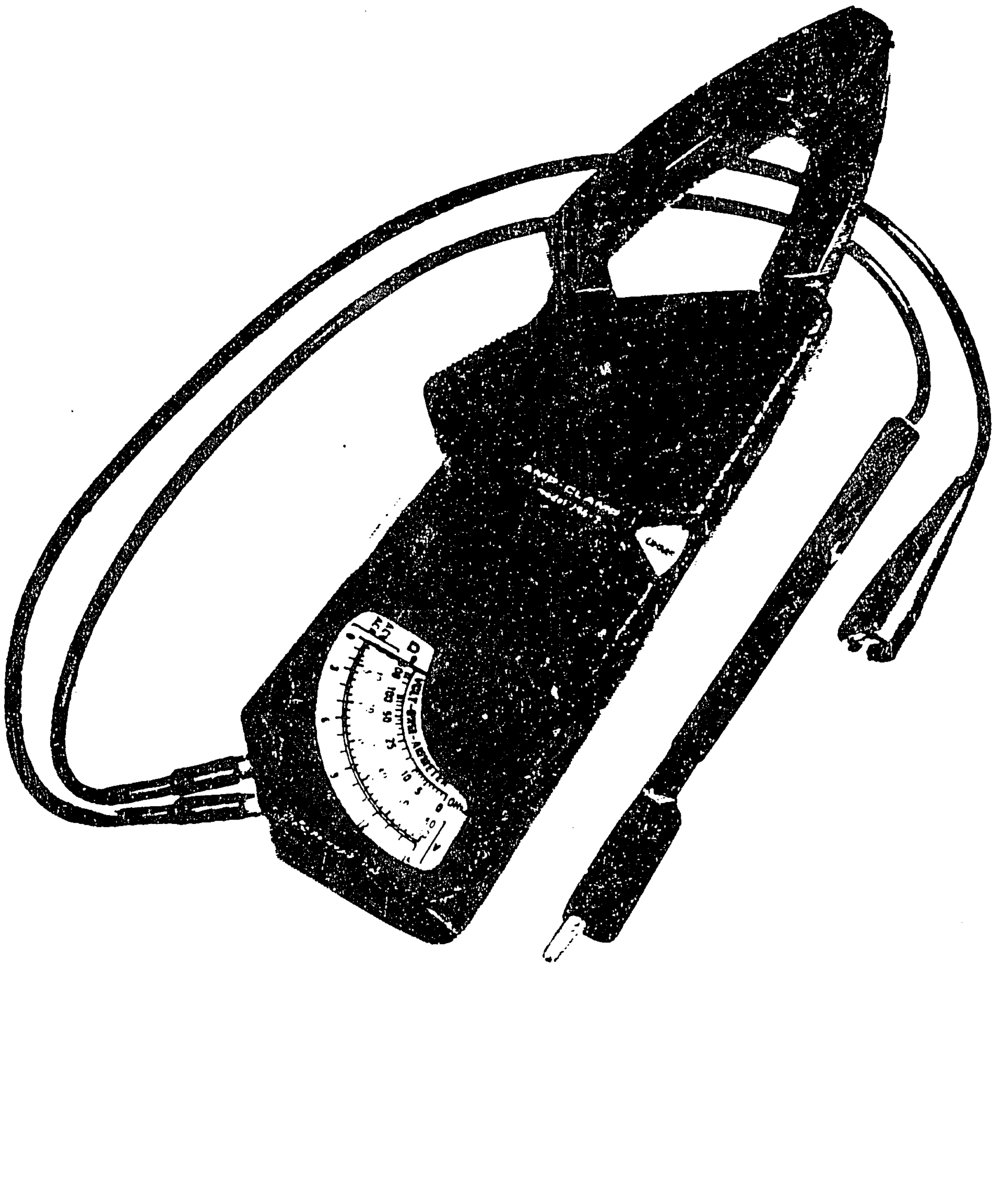
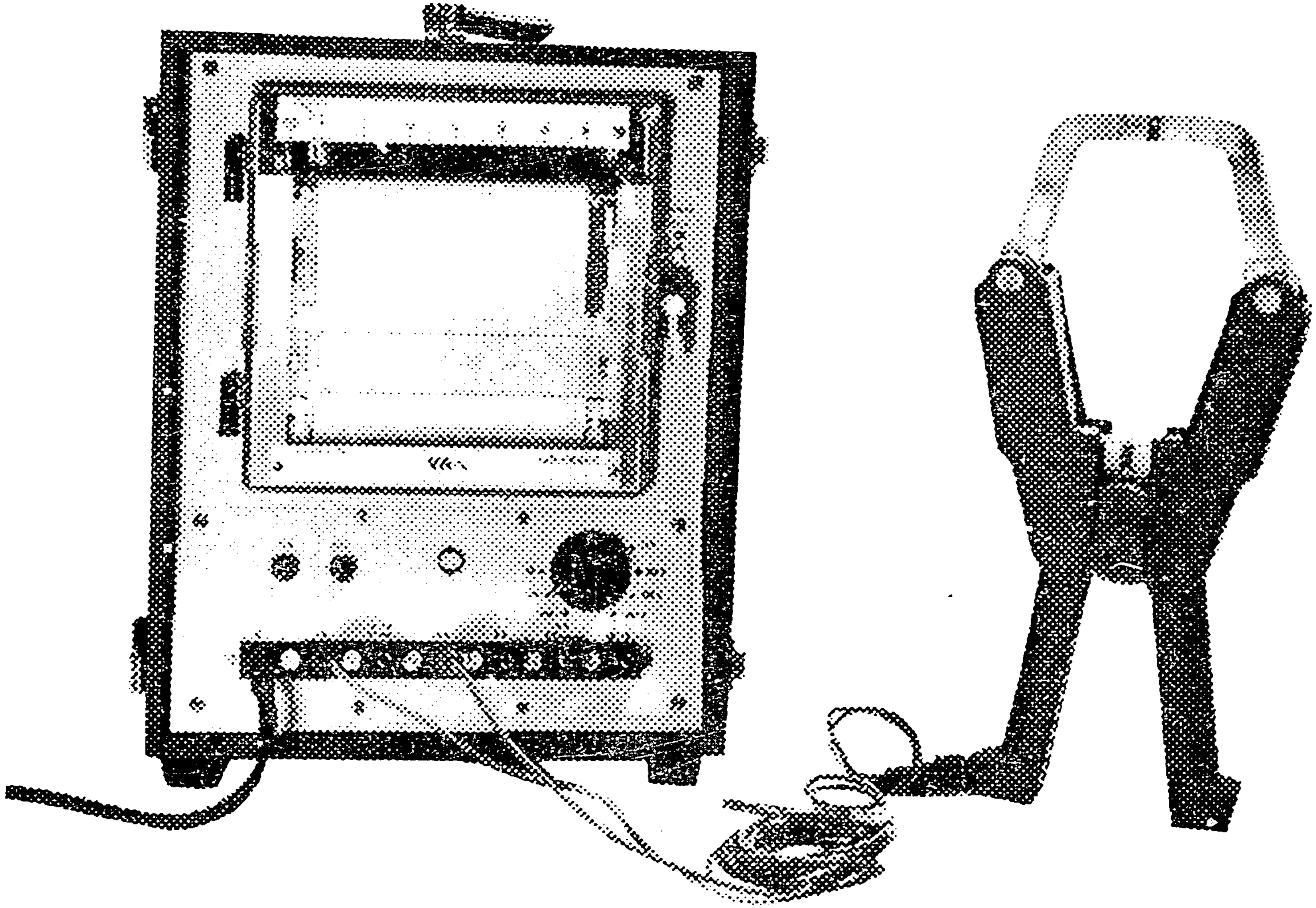


Exhibit 9.9

RECORDING AMMETER



an energy audit, it should be measured to ensure the proper operation of facility voltage reduction and distribution systems.

The instrument used to measure voltage is the **voltmeter.** In some cases, voltage measurement is combined with amperage and/or resistance in a device called the electrical multimeter. An example of a digital multimeter is shown in Exhibit 9.10. The instrument is used by connecting the voltage probes to the conductor (not the insulation) under study. Voltage is read directly on the appropriate scale on the instrument.

Safety precautions must be observed when measuring any electrical system. Care must be taken in the presence of uninsulated electrical conductors to avoid shock. Insulated gloves should always be worn.

Wattage is a measure of electrical power in a circuit. The **wattmeter** is used to determine the amount of power used by a piece of equipment. The recording ammeter or clamp-on ammeter can also be used to determine power consumption indirectly, since the apparent power in a circuit is equal to the product of current times voltage times the square root of the number of phases in the power system. (The actual power in a circuit is the product of apparent power and power factor).

The wattmeter consists of three clip-type terminals, one of which is distinguished by a mark (#1), a current transducer, and a display. The wattmeter is used by making one connection to each leg of the polyphase power system at the device being measured, and connecting the current transducer around the same legs as the marked clip. Power in the circuit is read directly from the instrument. A sample wattmeter is shown in Exhibit 9.11. The wattmeter shown is of the instantaneous clamp-on type. Wattmeters are also available that provide records in the form of graphs or as a summing meter.

The wattmeter is used in a different manner for each type of power supply encountered. Some combinations are described below (see Exhibit 9.12).

- Active power, no neutral, balanced load, three phase: clips are clipped in arbitrary sequence onto each leg; current transducer is clipped onto the same leg as the marked terminal. The instrument directly indicates active three-phase power.

Exhibit 9.10

DIGITAL MULTIMETER

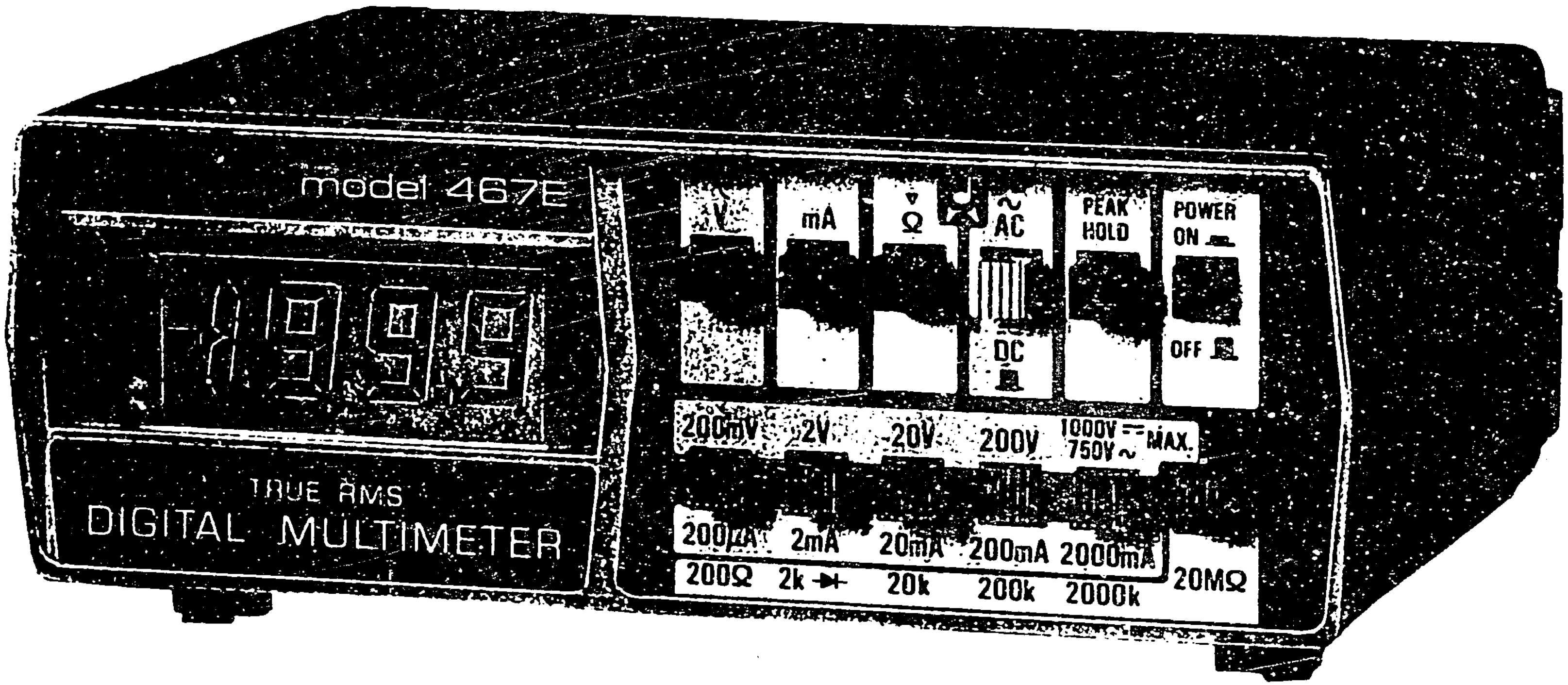


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Exhibit 9.11

CLIP ON WATTMETER

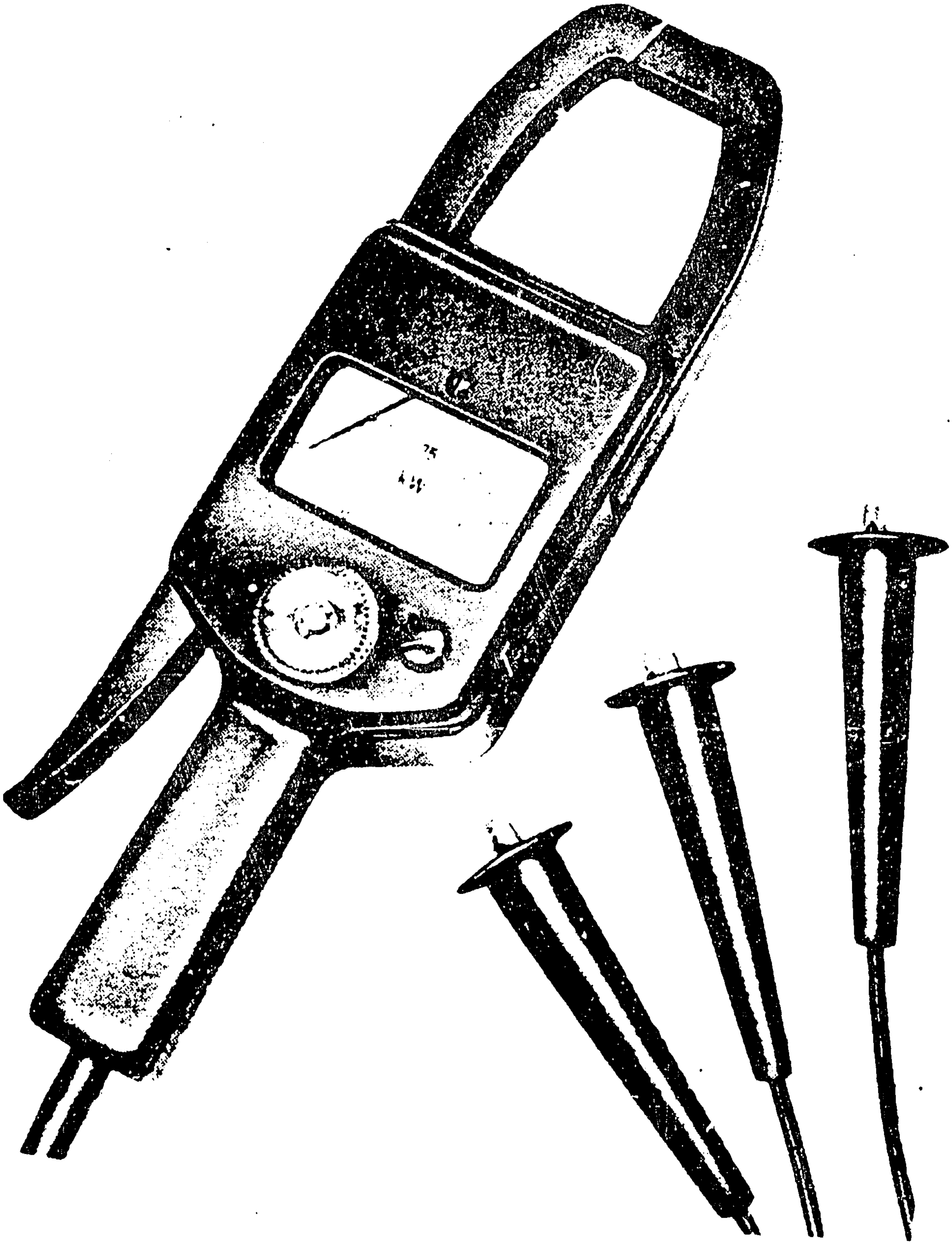
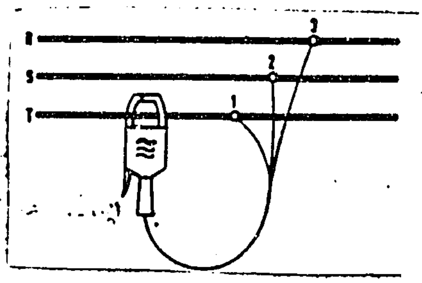


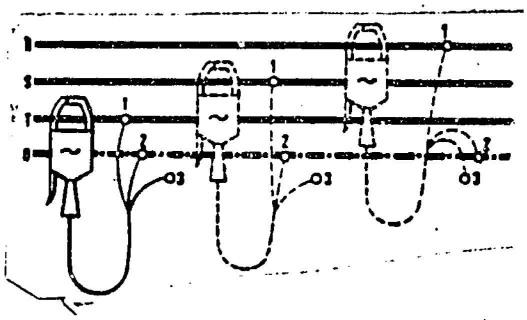
Exhibit 9.12

EXAMPLES OF WATTMETER USAGE

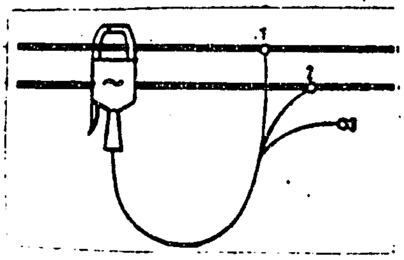
ACTIVE POWER NO NEUTRAL
BALANCED LOAD THREE PHASE



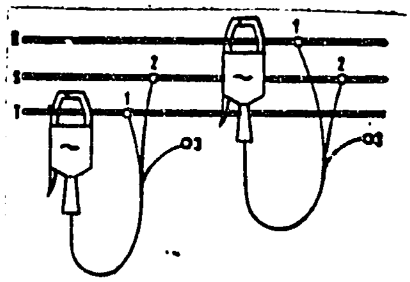
ACTIVE POWER NEUTRAL
UNBALANCED LOAD THREE PHASE



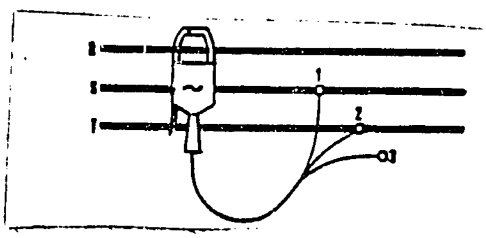
ACTIVE POWER SINGLE PHASE



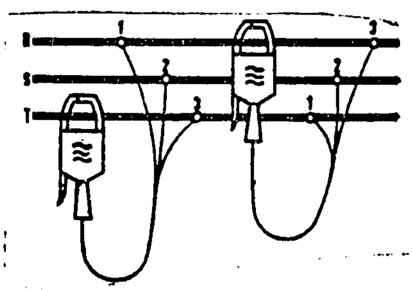
ACTIVE POWER NO NEUTRAL
UNBALANCED LOAD THREE PHASE



REACTIVE POWER NO NEUTRAL
BALANCED LOAD THREE PHASE



REACTIVE POWER NO NEUTRAL
UNBALANCED LOAD THREE PHASE



- Active power, neutral, unbalanced load, three phase: the marked clipped and the current transducer are connected to one of the three legs and the clip marked #2 is clipped to the neutral. The third clip is not used. The instrument measures the active power of one phase only; the process must be repeated for the other phases. The measured values are added.
- Active power, single phase: use the same procedure as described immediately above.
- Active power, no neutral, unbalanced load, three phase: two clip-on wattmeters is needed. Clip #2 for both meters are connected to the same phase. The marked clip and current transducer for the first wattmeter are connected to one of the remaining phases, while the marked clip and current transducer for the other wattmeter are connected to the remaining phase. Clip #3 for both meters is unused. The measured values are added.
- Reactive power, no neutral, balanced load, three phase: the marked clip and clip #2 are connected to two phases; the current transducer is connected to the remaining phase. Clip #3 is not used. The reactive power is determined by multiplying the reading by 1.73.
- Reactive power, no neutral, unbalanced load, three phase: this measurement requires two wattmeters. The three terminal clips on the wattmeter are indicated as #1 (the marked clip), #2, and #3. The clips for each meter are connected as follows:

Phase	Meter #1	Meter #2
1	Clip #1	Clip #3
2	Clip #2	Clip #2
3	Clip #3	Clip #1

The current transducer for each meter is connected to the same phase as clip #3 for that meter. The reactive power is found to be the difference between the two readings divided by 1.73.

Safety precautions must be observed when measuring any electrical system. Care should be taken in any attempt to connect a current transducer or clip to any bare (uninsulated) electrical conductor. Insulated gloves should always be worn.

The last electrical measurement to be covered here is power factor. A **power factor meter** is used for this measurement; an example of a clip-on power factor meter is presented in Exhibit 9.13. Physically, the clip-on power factor meter is very similar to the wattmeter previously discussed. The power factor meter incorporates part of the wattmeter mechanism. The instrument incorporates a current transducer and three clip-type terminals, one of which is distinguished by a mark (#1). A direct reading display is also provided.

The marked terminal and the current transducers are connected to one of the three phases; the other two clips are connected to the other phases in phase order. The instrument indicates improper connection if the indicating needle deflects in the wrong direction when activated (before connection of current transducer). In this case, exchange clips #2 and #3. The current transducer is connected to the same phase as clip #1. For the meter shown, a reading is obtained by rotating the knob until the indicating needle is centered. The power factor scale is coupled to the knob, and a direct reading is taken.

It is recommended that separate power factor measurements be made for each phase when there is a gross imbalance in phase current. The power factor in the three phase system is then computed by taking a weighted average of power factor in relation to phase current:

$$\text{Three phase power factor} = \frac{(A_1 \times PF_1) + (A_2 \times PF_2) + (A_3 \times PF_3)}{A_1 + A_2 + A_3}$$

where A = amperage in each phase

PF = power factor in each phase.

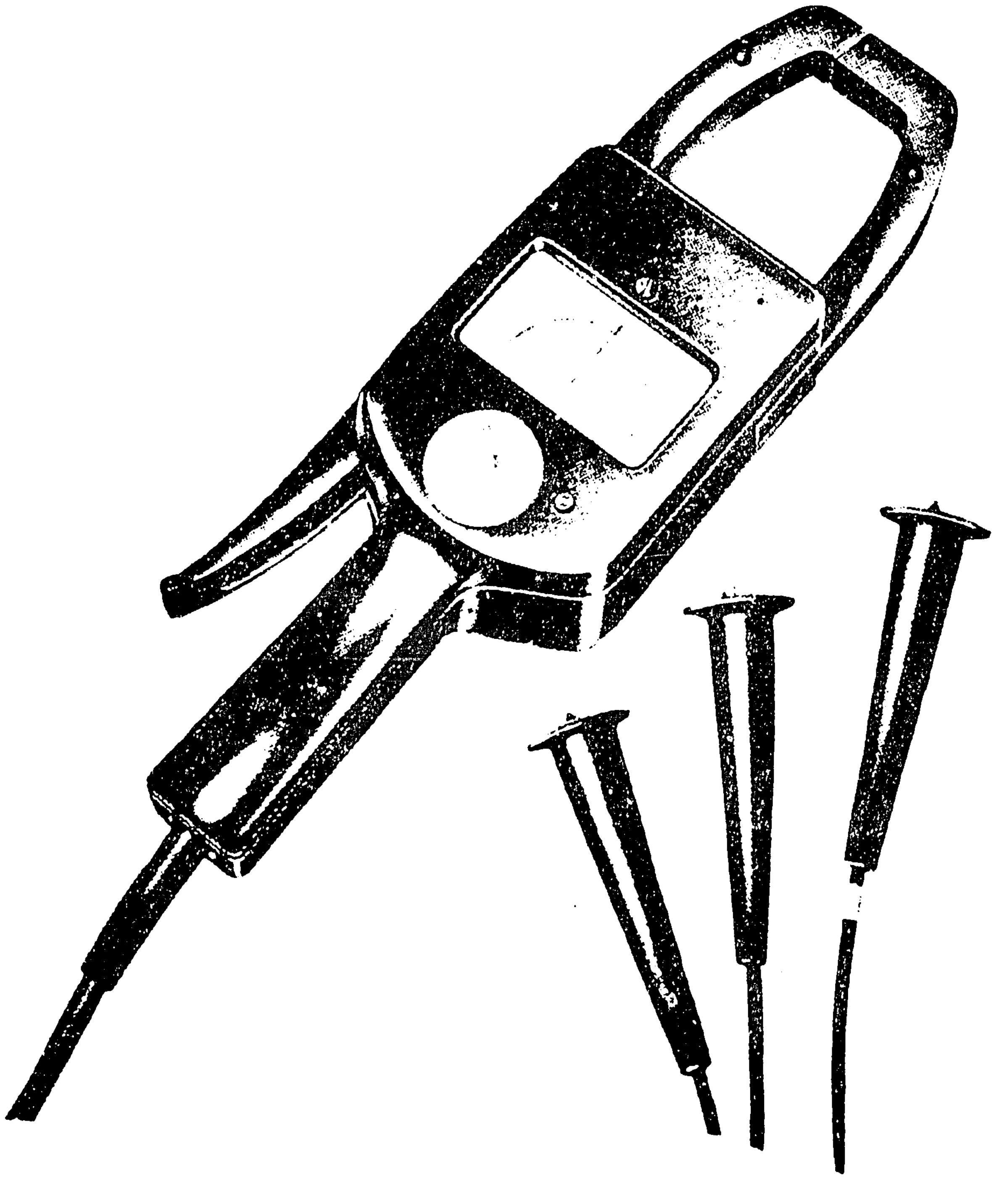
Safety precautions must be observed when measuring any electrical system. Care should be taken in any attempt to connect a clip or current transducer to any bare (uninsulated) electrical conductor. Insulated gloves should always be worn.

FLOW MEASUREMENT

There are several different instruments available for use in energy auditing for measurement of gas and liquid flow.

Exhibit 9.13

POWER FACTOR METER



The simplest flow measurement device is the **pitot tube**, used in conjunction with a **manometer**. The pitot tube is inserted into the air stream whose velocity is to be measured. It operates on the principle that an air flow across the end of an open tube causes a pressure drop. That pressure drop can be measured with the manometer.

The manometer is a U-shaped tube that is partially filled with some liquid, generally water or mercury. One end is generally open to the atmosphere, while the other end is connected to the pitot tube. The pressure drop is indicated by a difference in height between the two liquid columns of the U tube.

When using a water-filled manometer, velocity is calculated using the following equation:

$$V = 420.4 \times (h/d)^{1/2}$$

where V = air velocity, meter per minute
h = height difference between columns, millimeter
d = density of air, kg per cubic meter.

This expression can be used with any system of measurement by application of the appropriate conversion factors. An illustration of a pitot tube and manometer appears in Exhibit 9.14.

The **velometer** operates on the same principle as the pitot tube. This instrument is generally sold as a kit, with a number of probes available for use under different flow conditions. Instead of requiring the use of a manometer for measuring pressure drop, a built-in direct reading meter is provided. A velometer is illustrated in Exhibit 9.15.

The use of pitot tubes or velometer probes for flow measurement has a serious drawback: velocity is measured at only one location. In practice, the velocity of a gas in a duct is not uniform across any section. Hence, a traverse is usually made to determine average velocity. The best method for velocity measurement is the equal area traverse method.

With a circular duct, the cross-section is divided into six or eight concentric rings of equal area (see Exhibit 9.16). Measurements are taken at specified locations across two diameters at right angles to each other. For a rectangular duct, a similar approach is

Exhibit 9.14

PITOT TUBE AND MANOMETER

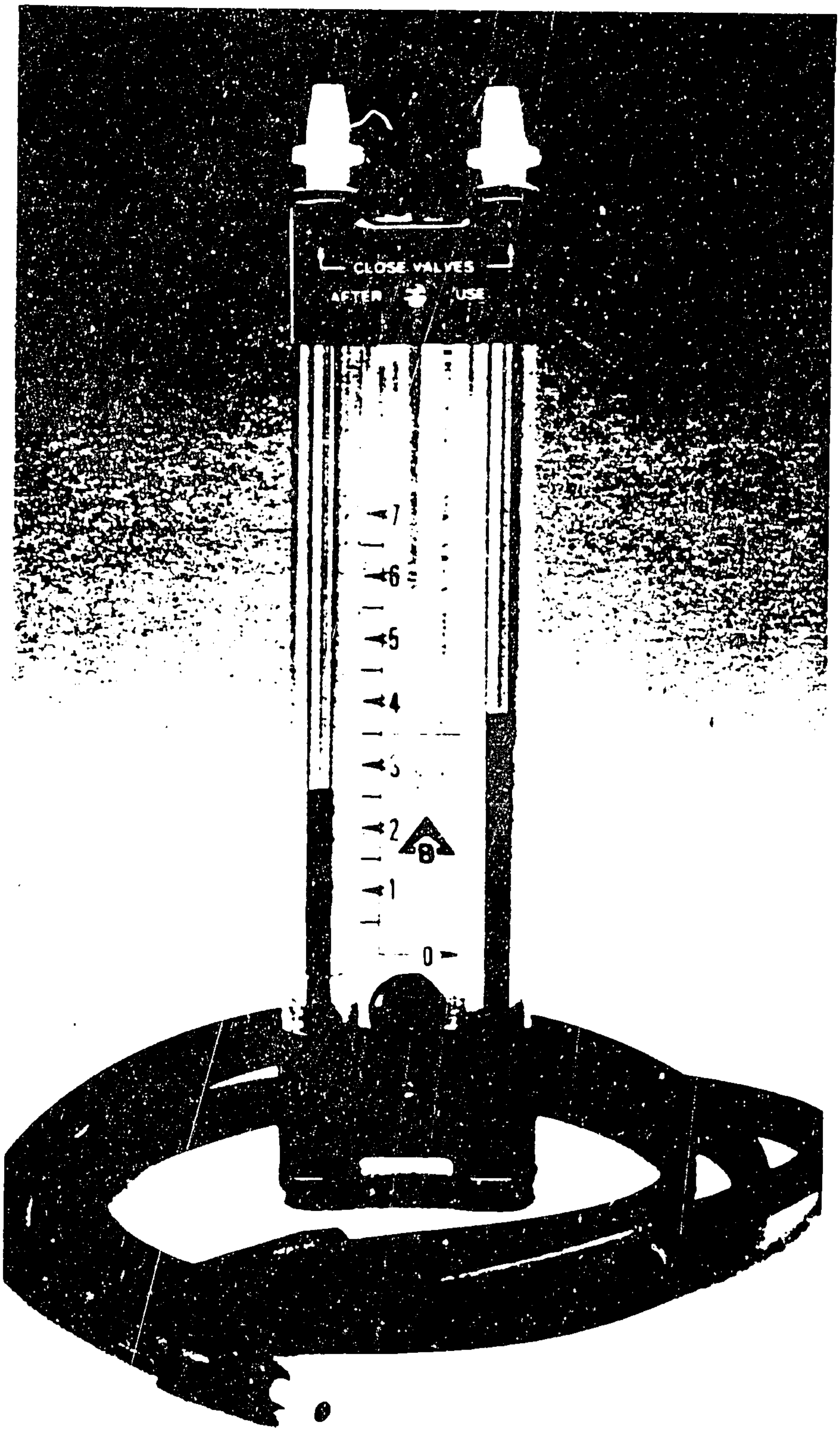
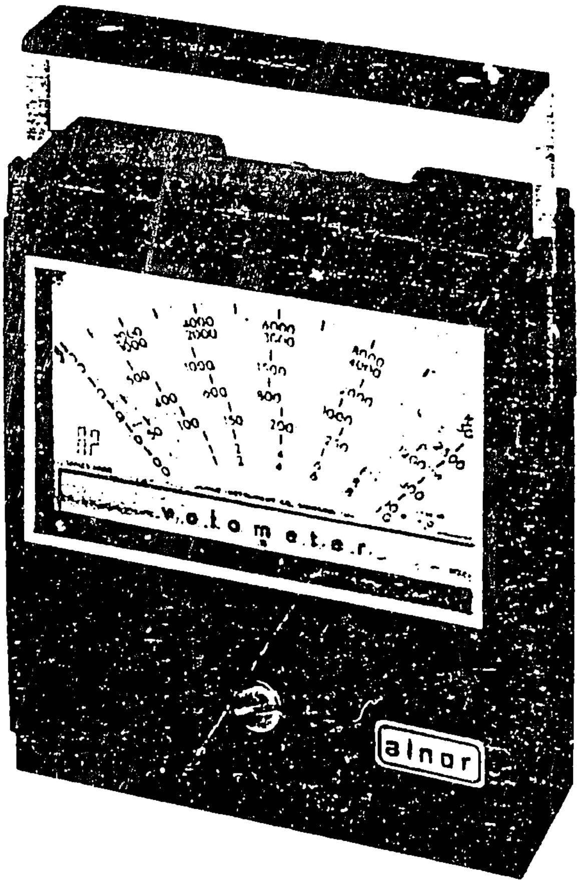


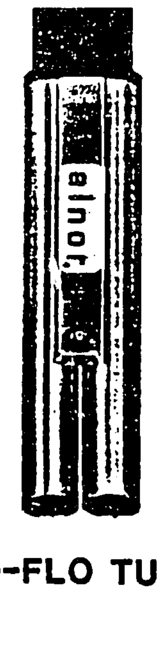
Exhibit 9.15

VELOMETER

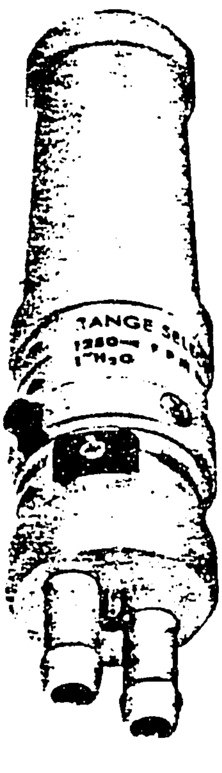


VELOMETER

PITOT PROBE



LO-FLO TUBE

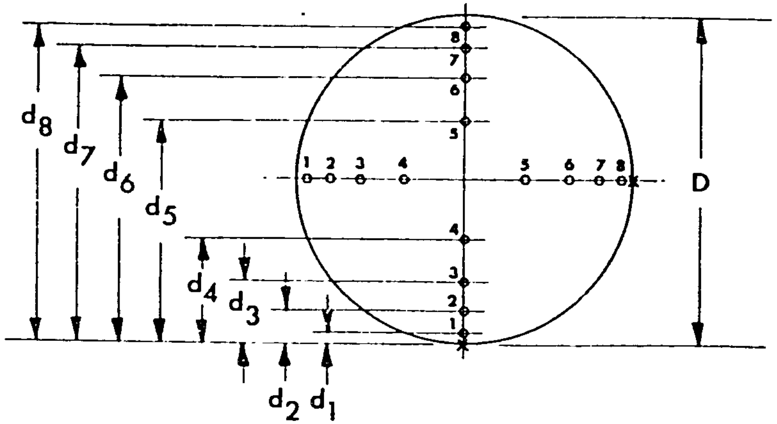


RANGE SELECTOR

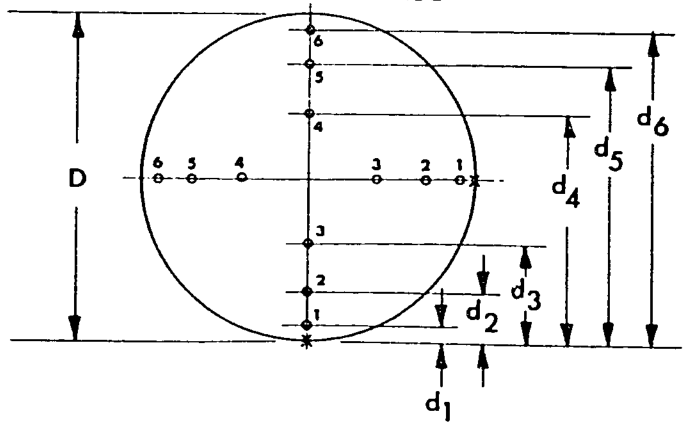
Exhibit 9.16

EQUAL AREA TRAVERSE FOR CIRCULAR DUCTS

EIGHT POINT TRAVERSE



SIX POINT TRAVERSE



Traverse Method	Probe immersion in Duct Diameters									
	d_1	d_2	d_3	d_4	d_5	d_6	d_7	d_8	d_9	d_{10}
6 point	0.043	0.147	0.296	0.704	0.853	0.957	–	–	–	–
8 point	0.032	0.105	0.194	0.323	0.677	0.806	0.895	0.968	–	–

taken by dividing the duct into 16 to 64 equal rectangular areas and taking measurements at the center of each rectangle (see Exhibit 9.17). For either duct, the bulk velocity is found by using either the average of individual velocity readings, or the average of the square roots of manometer indication; it is not proper to average manometer indication directly. The volumetric flow rate through the duct can be determined by multiplication of average flow rate by the cross-sectional area of the duct.

Easily usable and portable instrumentation for liquid flow measurement is not as readily available. One type, the **ultrasonic flow meter,** consists of a set of transducers that are coupled with a display computer (see Exhibit 9.18). The transducers are clamped onto opposite sides of the pipe containing the liquid under study. One transducer sends an ultrasonic signal into the fluid that is detected by the other transducer. Velocity is determined either by measurement of time required to receive the transmitted signal or by measurement of the signal's frequency change owing to the Doppler effect.

The equipment is expensive to acquire and may be limited in application. Very dirty liquids (those with large quantities of suspended solids) cannot be measured accurately.

A less expensive and easy to use metering instrument is the **rotameter,** illustrated in Exhibit 9.19. The rotameter consists of a float that is free to move vertically in a transport tube. The fluid to be measured enters at the bottom of the tube and passes through the annulus formed between the float and tube well. At any particular flow rate, the float will assume a defined position in the tube. The rotameter may be obtained precalibrated for specific fluids and in a range of sizes.

For permanent installation, **positive displacement meters** are available (see Exhibit 9.20). These instruments are useful for metering the flow of liquids and gases. The fluid being measured flows into compartments of definite size. As the compartments fill, they rotate to allow the fluid to leave the meter. The flow rate through the meter is equal to the product of compartment size, number of compartments, and rate of rotation of the rotor. These meters are particularly useful in determining flow over long periods of time.

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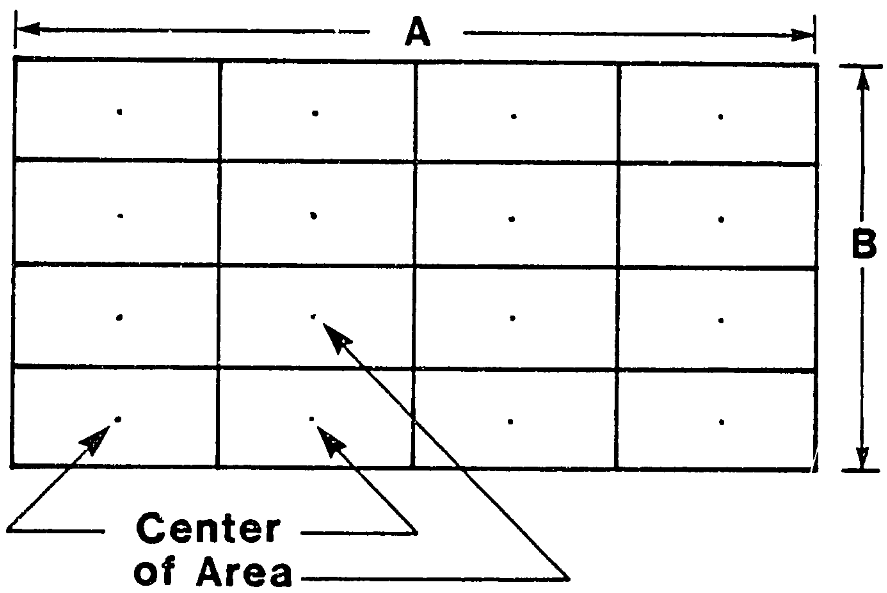
Exhibit 9.17

EQUAL AREA TRAVERSE FOR RECTANGULAR DUCTS

Use 16 to 64 Equal Area Rectangles



Make Measurement at Center of Rectangle

Exhibit 9.18

ULTRASONIC FLOWMETER

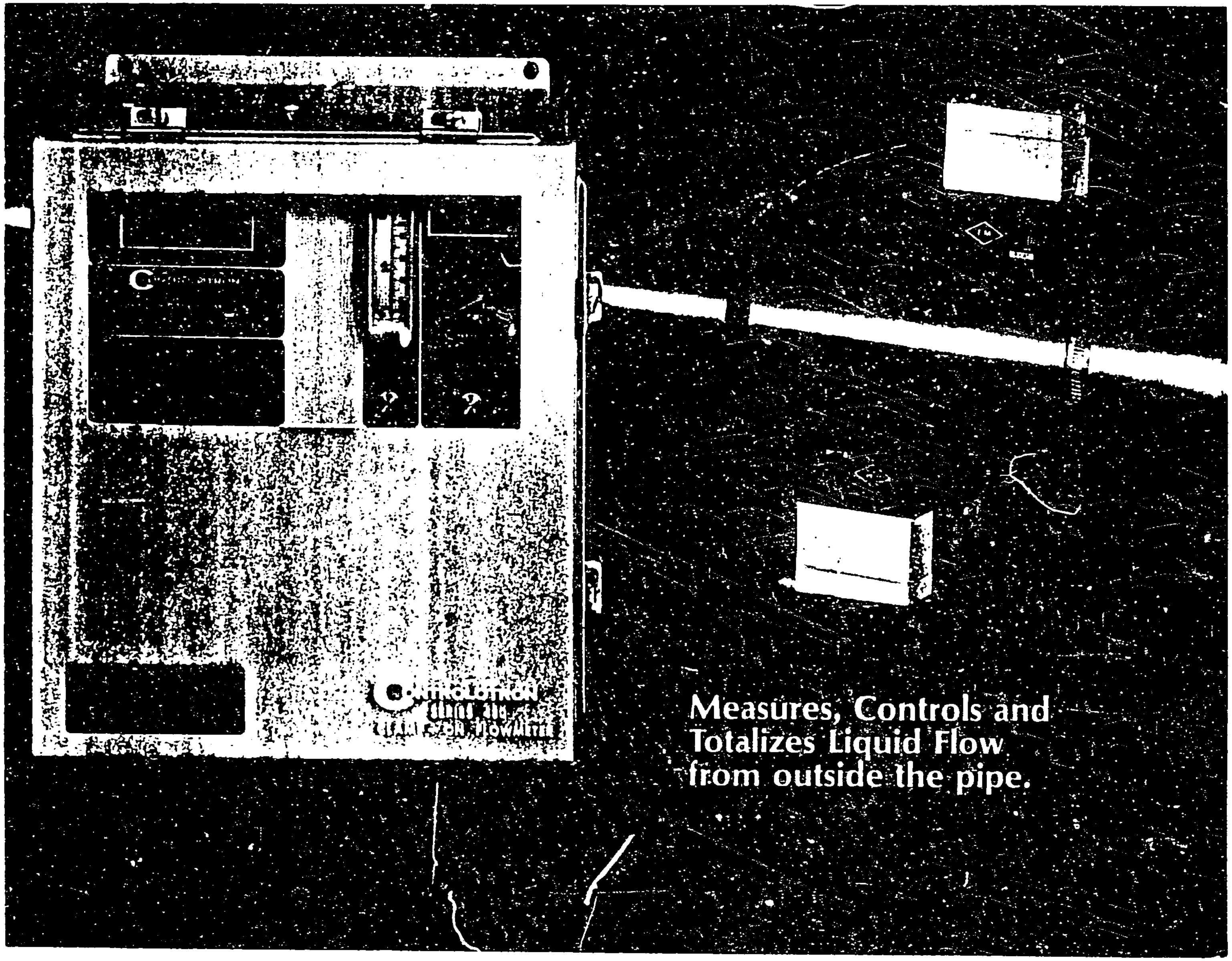


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Exhibit 9.19

Rotameter

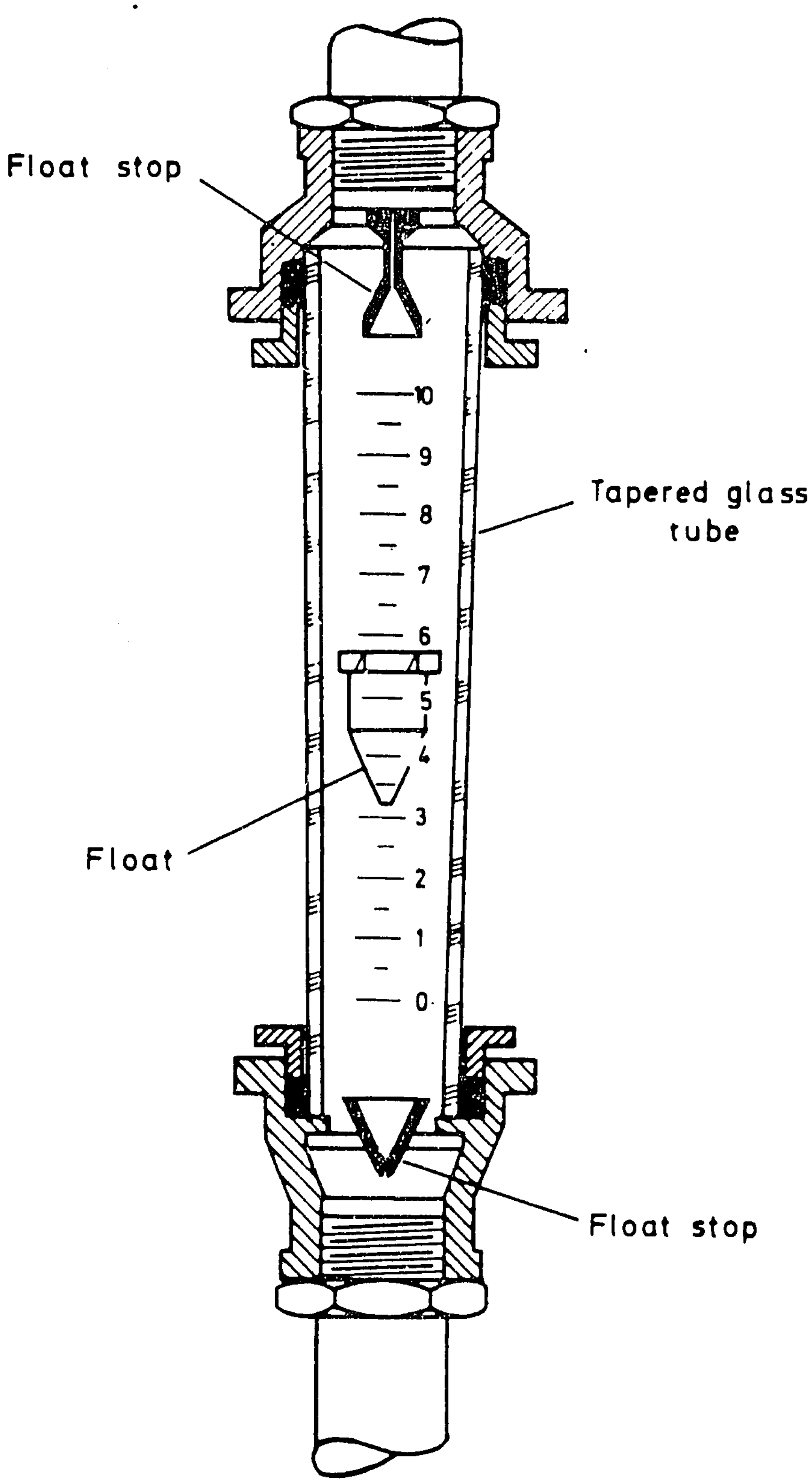
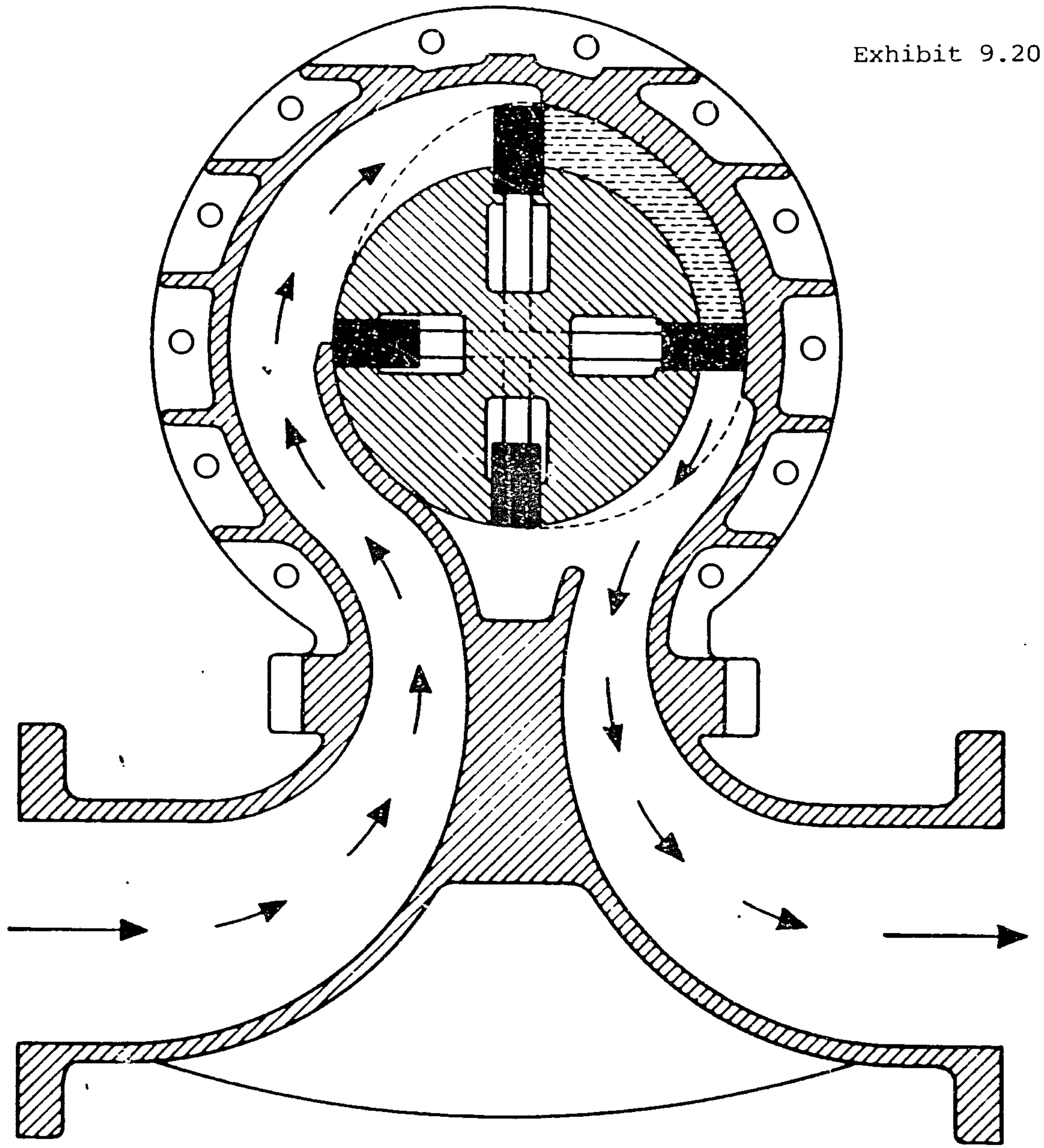


Exhibit 9.20



Positive displacement meter. Principle of operation

COMBUSTION EFFICIENCY MEASUREMENT

The measurement of combustion efficiency requires temperature measurements, psychrometric measurements, and the analysis of the products of combustion. The following paragraphs focus on combustion efficiency measurements of boilers. However, the principles, procedures, and instruments described for boilers may be applied to other combustion systems such as kilns and direct-fired dryers.

Boilers operate at different efficiencies, depending on their load. To determine boiler combustion efficiency in an accurate manner, boilers must be tested over the whole range of load operating conditions. At a minimum, boilers should be tested at low-fire, medium-fire and high-fire conditions (at about one-third, two-thirds and full load). To cover the complete range of boiler operating conditions, they should be tested at increments of 10 percent of full load.

Before testing a boiler, it should be allowed to operate at the load to be tested for 15 to 30 minutes prior to testing to achieve steady-state conditions. Three sets of tests should be made at each load condition. The measurements taken at each load condition are used to calculate combustion efficiency individually; the three efficiencies for each load are then averaged.

Combustion system testing requires acquisition of the following data:

- Temperature of entering combustion air
- Temperature of combustion gases
- Composition of combustion gases
  - carbon dioxide (CO_2)
  - carbon monoxide (CO)
  - oxygen (O_2)
- Amount of smoke in combustion gases
- Firebox and stack draft
- Amount of dissolved solids in boiler water.

Temperature measurements for entering combustion air and combustion gases are required to determine the "net stack temperature." Any appropriate temperature measuring device may be used. It is recommended that a mercury-in-glass thermometer be used to determine entering combustion air temperature, while an appropriate thermocouple be used to measure the temperature of the combustion gases.

Entering combustion air temperature should be measured at the point where it enters the system. In the case of a forced draft boiler, for instance, combustion air temperature is measured at the fan inlet. Combustion gas temperature should be measured at a point as close to the heat transfer section of the combustion system as possible. In a boiler, access to the stack at as close a point as possible to the breeching is recommended. The net stack temperature is the difference between the combustion gas temperature and entering combustion air temperature.

Combustion gases are sampled at the same point the flue gas temperature is taken. Because some flue stacks may have "dead spots," it is useful to make measurements with a velometer or other flow measurement device to ensure that the gas samples are indeed well mixed.

Combustion gases are analyzed for three components: carbon dioxide, carbon monoxide, and oxygen. With good mixing, perfect combustion is obtained when (a) the combustion gas analysis shows no carbon monoxide or oxygen, and (b) the maximum amount of carbon dioxide for that fuel type and flow rate. In practice, however, the two conditions are rarely met.

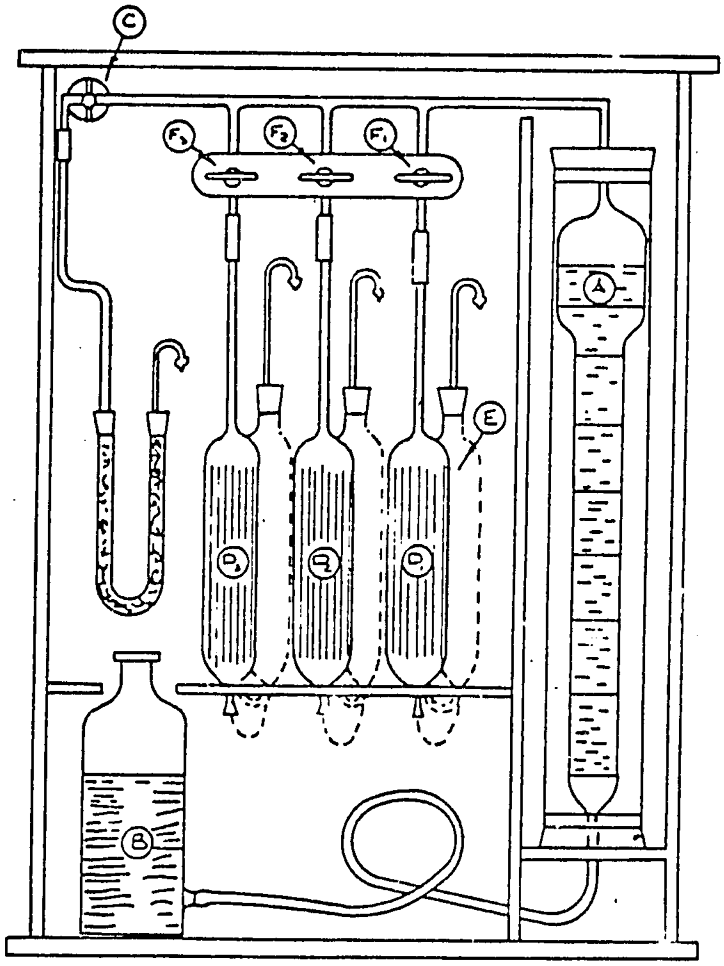
A number of instruments can be used for analyzing combustion gases. These may be divided into two categories:

- Chemical analysis
- Electrochemical analysis.

<u>Chemical analysis</u> devices include the <u>Orsat apparatus</u> and <u>Fyrite analyzer</u>. The <u>Orsat apparatus</u> is the traditional instrument used for combustion gas analysis. This instrument, illustrated in Exhibit 9.21, is very fragile, not particularly portable, and requires a great deal of skill in use. A measured amount of combustion gas is induced into the instrument. The combustion gas reacts with various chemicals that cause the various components of interest -- carbon dioxide, carbon monoxide, and oxygen -- to be absorbed from the gas.

Exhibit 9.21

ORSAT APPARATUS



A GRADUATED BURETTE

B ASPIRATOR BOTTLE

C COCK FOR TAKING IN GAS SAMPLE

D_1 D_2 D_3 ABSORBENT LIQUIDS

E DISPLACEMENT RESERVOIRS

F_1 F_2 F_3 COCKS FOR BURETTES

ORSAT GAS ANALYSIS APPARATUS.

The successive volume changes of the gas indicate the amounts of carbon monoxide, carbon dioxide, and oxygen in the gas sample.

A more portable chemical analysis kit is the so-called **Fyrite analyzer**, illustrated in Exhibit 9.22. Fyrite analyzers are available for carbon dioxide and oxygen analysis. As with the Orsat apparatus, a chemical reaction with the gas component being measured causes a volume change that, in turn, indicates the quantity of that component in the gas sample. In the paragraphs below, the use of the Fyrite analyzer for measurement of oxygen and carbon dioxide is discussed (see Exhibit 9.23).

The Fyrite should be in proper operating condition, with the proper amount of chemicals added. Before beginning a series of tests, the zero scale should be adjusted. Holding the Fyrite upright, depress the valve on the device top and release. Turn the indicator bottle upside down until all the fluid has run down and then turn the bottle right side up again. Repeat this operation three more times. Then, hold the bottle at a 45-degree angle for about 5 seconds to drain fluid droplets from the inside surfaces. Hold the bottle level and depress and release the valve again. Adjust the zero scale to correspond to the top of the liquid column. (Note that if the liquid level drops more than 1/2 inch (1.25 cm) after depressing the valve, repeat the procedure.)

The aspirator assembly consists of a length of tubing, a filter, and a rubber bulb. At one end of the tubing is a metal pipe; at the other is a rubber connecting tip. The open end of the metal tube is inserted into the gas stream to be measured. After insertion and before sampling, the rubber bulb should be squeezed about 20 times to purge the aspirator assembly of ambient gases.

To begin sampling, place the rubber connector flat against the valve on top of the Fyrite bottle. Depress the valve and steadily squeeze and release the aspirator bulb 18 times for oxygen analysis or carbon dioxide analysis. On the 18th squeeze, before releasing the rubber bulb, remove the connector from the top of the bottle and release the valve. The sample is then trapped for analysis.

Invert the bottle and reverse four times for oxygen and twice for carbon dioxide. This forces the gas sample through the absorbent chemical. Allow all the chemical to run back into the bottom of the bottle by holding it at a 45-degree angle for about 5 seconds.

Exhibit 9.22

FYRITE GAS ANALYZER

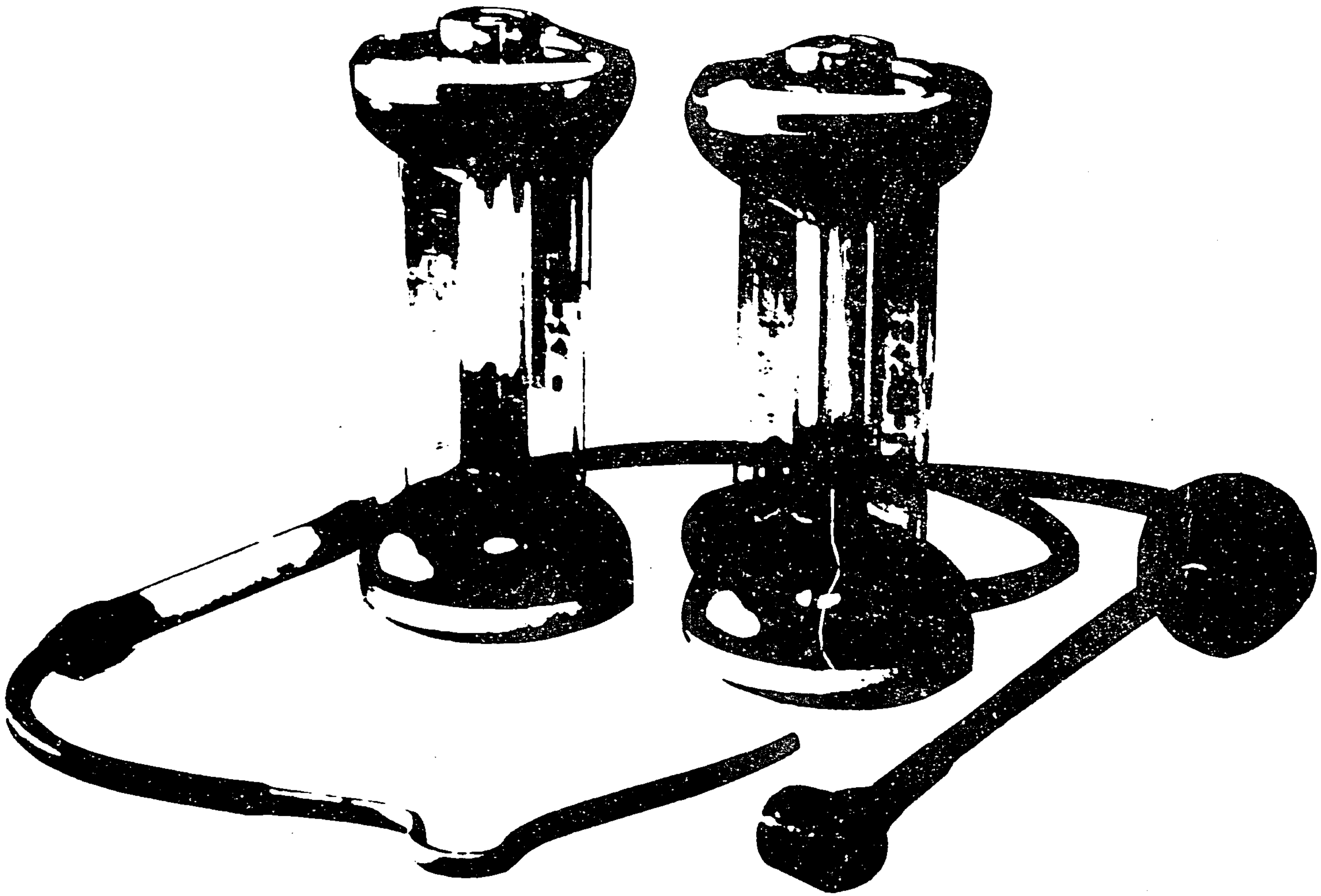


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Exhibit 9.23

Use of Fyrite Gas Analyzer

1. Adjust zero percent scale.

2. Purge gases from aspirator.

3. Pump sample into bottle.

4. Release aspirator from bottle.

5. Invert and release bottle to mix sample

   - 4 times for oxygen
   - 2 times for carbon dioxide.

6. Allow fluid to run into bottle

   - hold at 45-degree angle.

7. Hold upright and read gas content.

8. Depress valve to set for next sample.

9. Return to Step 3 for next analysis.

Holding the bottle upright, read the percent oxygen or carbon dioxide content of the gas from the scale. Before taking the next sample, depress the valve on top of the bottle to dispel the gas sample.

The Fyrite bottles are used for carbon dioxide and oxygen measurement only. Carbon monoxide readings should also be taken with certain types of fuels to ensure that complete combustion is taking place. Carbon monoxide content can also be determined by chemical means. For this purpose, a monoxide indicator such as that shown in Exhibit 9.24 is used. A gas sample is drawn into contact with a chemical reagent in a glass tube. Carbon monoxide causes a stain to appear in the indicator tube; the length of the stain is compared with a calibrated scale to determine percentage carbon monoxide content. A new indicating tube must be used for every measurement.

Electrochemical devices (also called combustion computers) are also used for combustion efficiency measurement. These devices incorporate the temperature measurement and gas analysis functions described previously and directly calculate combustion efficiency. The instrument incorporates a microprocessor which allows the user to set the instrument to the type of fuel used. An example of an electrochemical combustion analyzer is illustrated in Exhibit 9.25.

Electrochemical instruments are faster and easier to use than chemical devices. An electrochemical analyzer consists of a gas sampling probe that is placed in the flue gas stream. The probe is connected to the analyzer by a length of tubing. The probe also contains a thermocouple that measures stack temperature. Gas samples are drawn through the probe by a pump. There is also a thermocouple present in the analyzer for determination of combustion air temperature. Hence, net stack temperature is automatically computed.

In use, the probe is placed in the flue gas stream, and the device is activated and set to the proper fuel type. At the end of a sampling cycle, the device determines:

- Oxygen content of gas sample
- Carbon monoxide content of gas sample
- Net stack temperature
- Carbon dioxide content (computed)

Exhibit 9.24

GAS ANALYZER FOR CARBON MONOXIDE

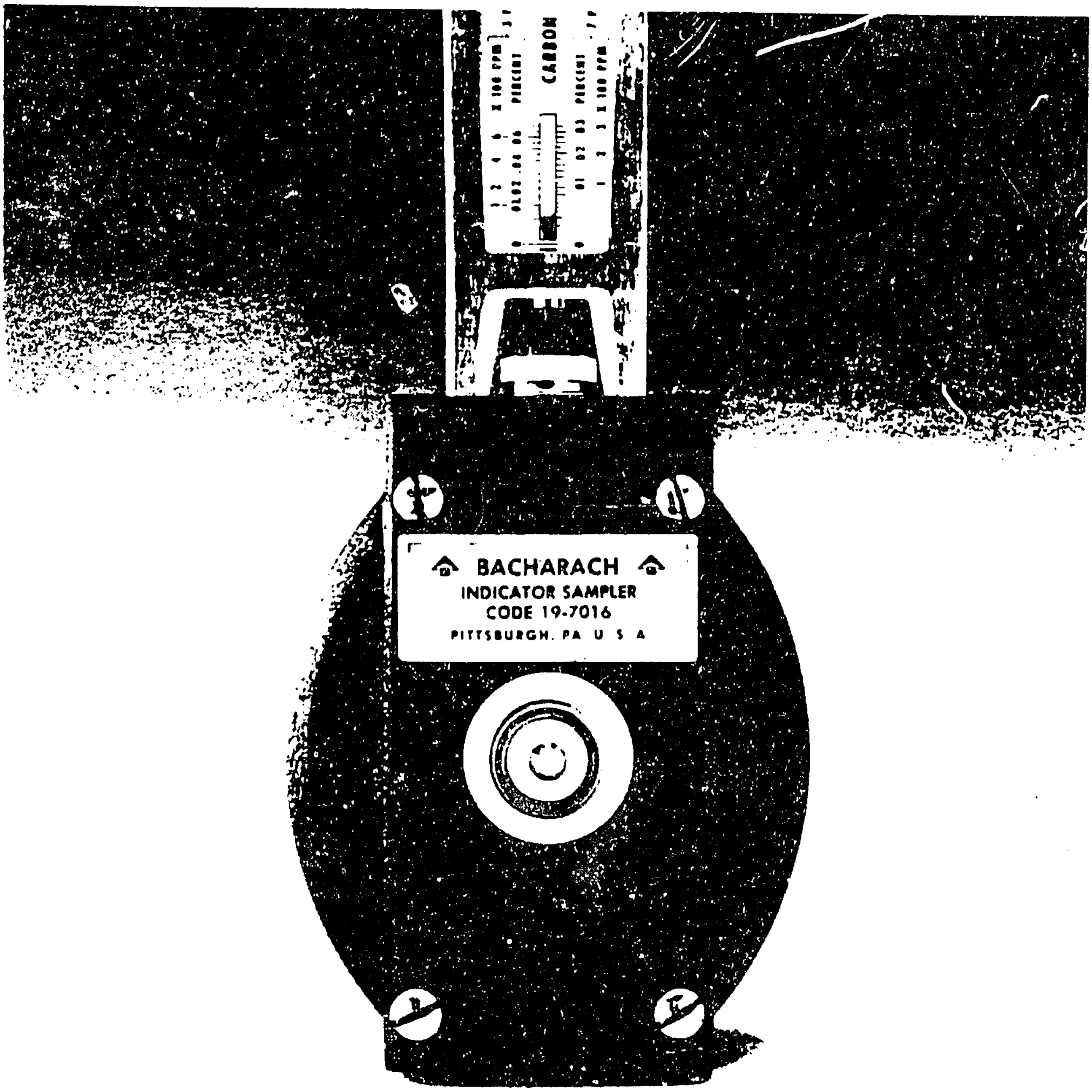
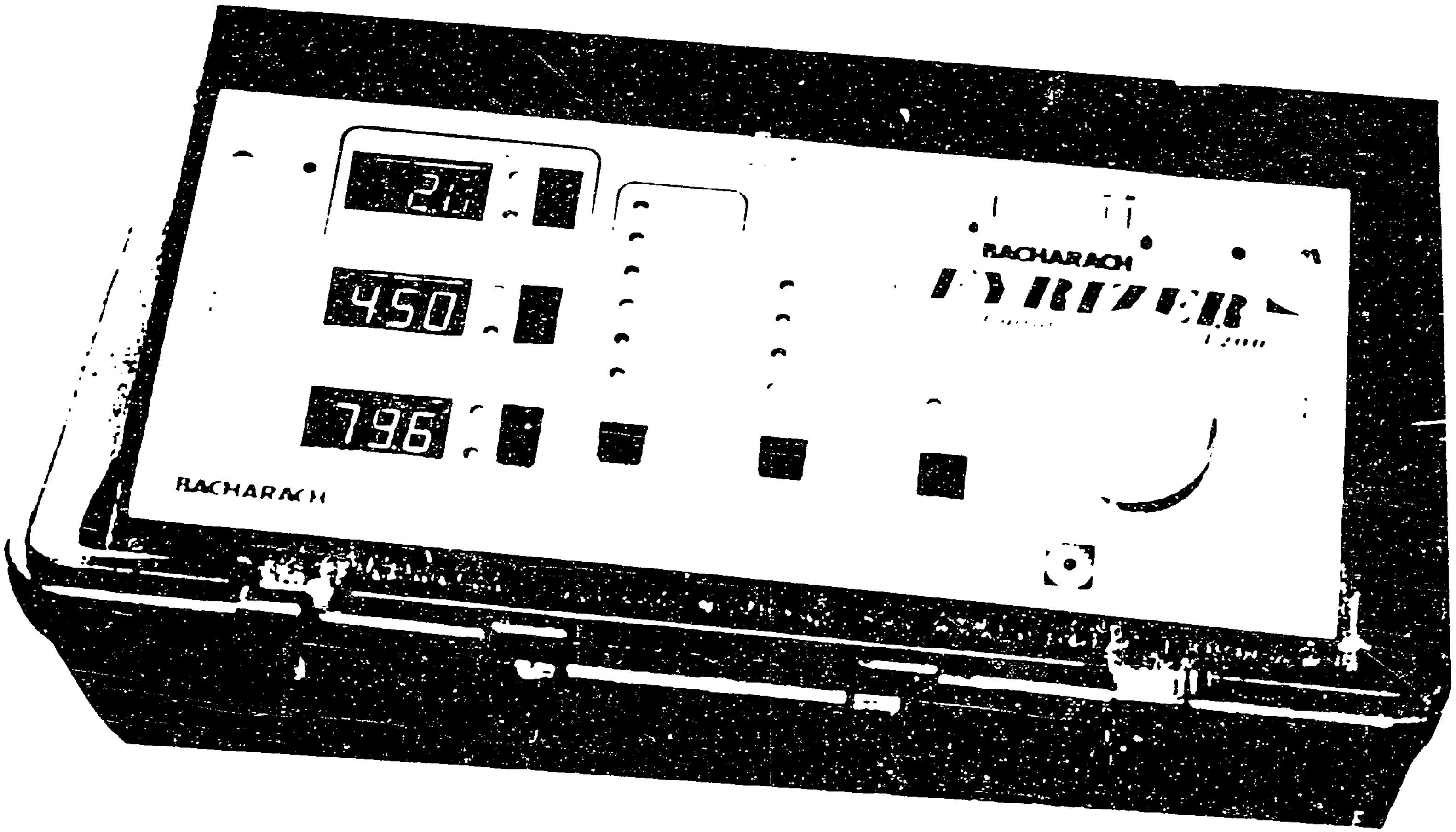


Exhibit 9.25

ELECTROCHEMICAL COMBUSTION ANALYZER



- Percent excess air (computed)
- Combustion efficiency (computed).

Measuring smoke in combustion gases can be performed with a **smoke test pump** as illustrated in Exhibit 9.26. Special filter paper is placed in the pump sampling port. The sample probe is placed in the combustion gas stream, and the pump handle is pulled through ten strokes to draw a measured amount of gas through the filter paper. The filter paper is removed from the pump and compared with a comparative scale to determine the extent of incomplete combustion. The ten spots on the scale range in equal photometric steps from white (spot 0) to black (spot 9). Burners firing No. 2 oil should not present a filter darker than spot #2, while a measurement comparable to spot #3 is acceptable for heavy fuel oils. The built-in pump of an electrochemical combustion gas analyzer can also be used for smoke testing in a similar fashion to the smoke test pumped discussed above.

It is also important to determine the draft at the firebox and at the stack. The draft indicates the pressure at which the combustion system operates. The intensity of the draft determines the rate at which combustion gases pass through the boiler or furnace, and the amount of air provided for combustion. Excessive draft can increase the stack temperature (causing incomplete heat transfer), while insufficient draft may cause smoking owing to insufficient combustion air.

Draft is measured with a pressure measurement device. The manometer, illustrated in Exhibit 9.14, may be used. Alternatively, special **draft gauges,** as illustrated in Exhibit 9.27, may be used. The draft gauge is used by inserting the probe into the area where draft is to be measured (either the firebox or the flue). The draft is read directly from the scale.

The last measurement to be covered in this discussion is a measure of dissolved solids in the boiler water. While this is not a combustion test, the amount of dissolved solids in boiler water is an indication of boiler heat transfer capability. High concentrations of dissolved solids in the boiler water indicates the potential for fouling of boiler heat transfer surfaces.

Exhibit 9.26

SMOKE TEST PUMP AND SCALES

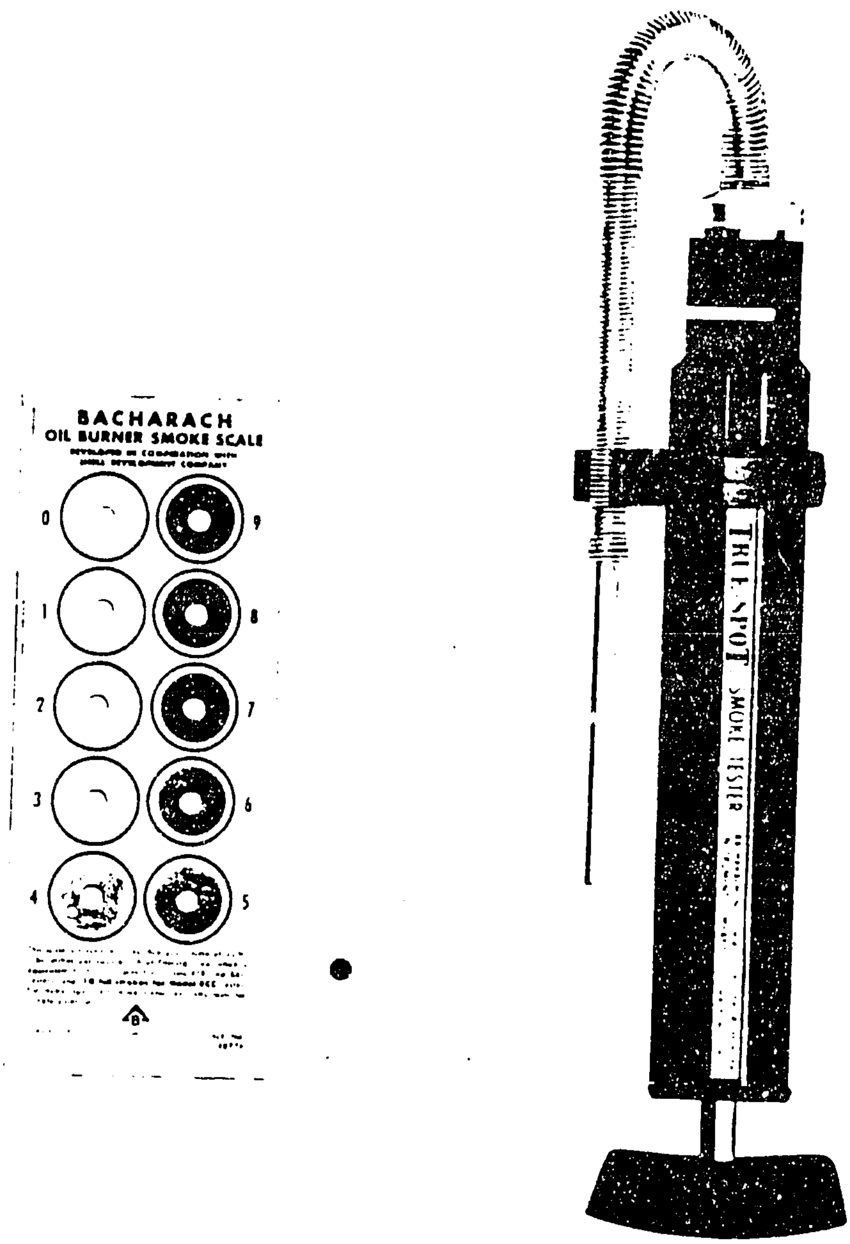
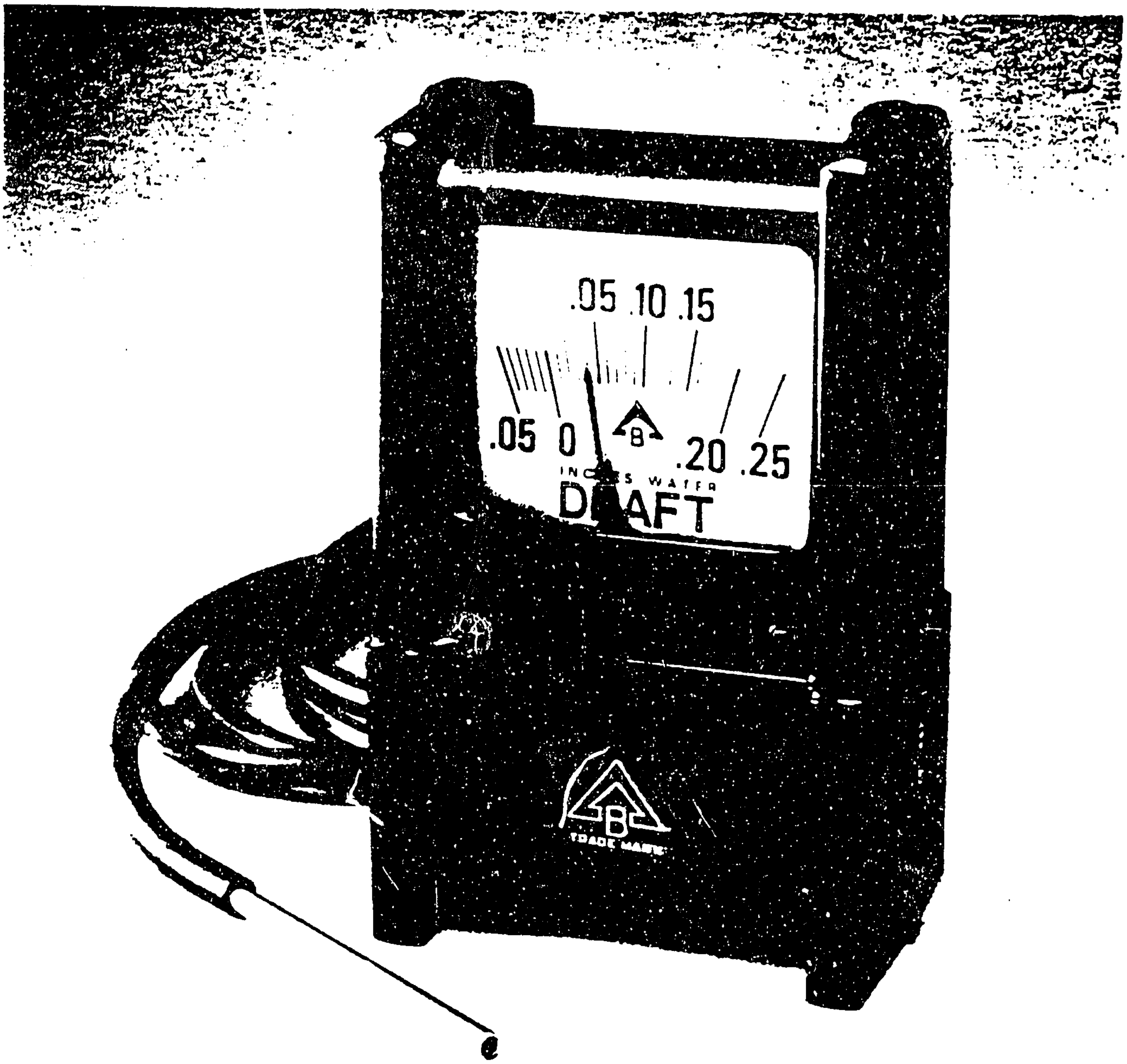


Exhibit 9.27

Draft Gauge



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A **conductivity meter**, or **total dissolved solids (TDS) meter**, is used to determine the concentration of dissolved solids in the boiler water. An example of a conductivity meter is illustrated in Exhibit 9.28. The meter measures the electrical resistance (the inverse of conductivity) of a liquid sample. Since pure water is not a conductor, its electrical conductivity is zero. However, solids dissolved in water will increase its conductivity. The meter shown is calibrated to give a direct reading of dissolved solids in parts per million.

A sample of boiler water is taken from a blowdown point. This sample is used to wash the sample cup on the meter. The cup is washed several times before filling with the actual sample to be measured. The cup is then filled with the sample to a point above the top electrode. The measurement button is depressed and the meter directly indicates the total dissolved solids concentration in the sample.

Other chemical tests of boiler water and boiler feedwater may be performed to determine the concentration of various ions. These tests can be performed as part of a program to specify proper water treatment for the boiler plant.

LIGHT LEVEL MEASUREMENT

Determining proper illumination levels involves:

- Definition of space served by luminaires
- Identification of type of luminaire in use
- Measurement of light level on task.

An example of a data form for light level survey measurements is presented in Exhibit 9.29. Each discrete area in the facility surveyed is indexed in Column 1 of the form. The location and principal use are noted in Columns 2 and 3, respectively.

The dimensions of the area, including actual length and width, are recorded in Column 4. The height refers to the height from the luminaire to the floor; this may be different from ceiling height if the lighting fixtures are suspended from the ceiling.

Exhibit 9.28

CONDUCTIVITY METER USED FOR DISSOLVED SOLIDS MEASUREMENT

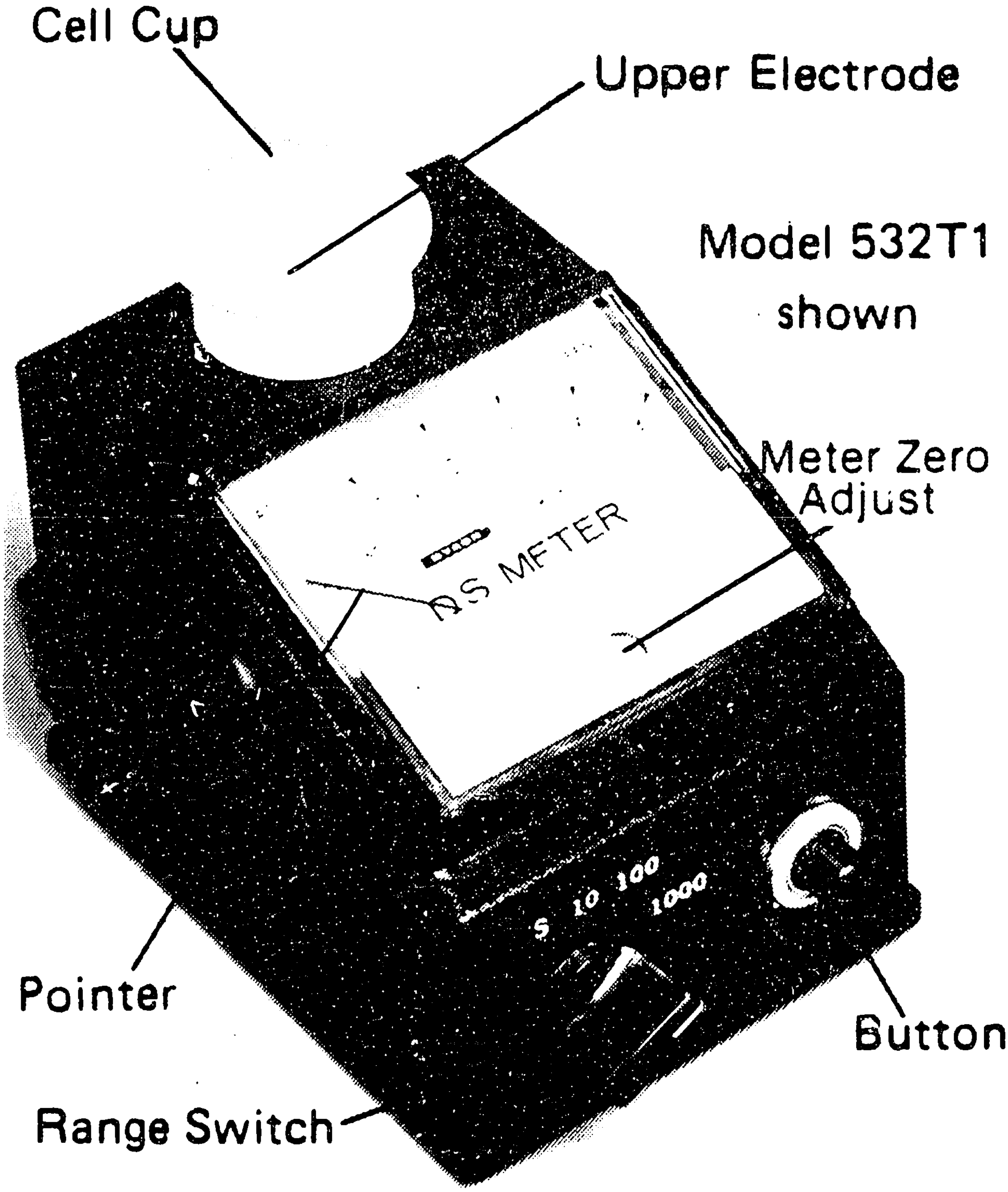

Exhibit 9.29

LIGHTING SURVEY	DATE:	BY:	
SITE NAME:		BUILDING:	
OUTSIDE CONDITIONS:		START TIME:	

ITEM NO.	LOCATION	AREA PRINCIPAL USE	DIMENSIONS	NUMBER OF LUMINAIRES	LAMP/LUMINAIRE DESCRIPTION *1, 2, 3		OBSERVED LIGHT LEVELS	ANNUAL HOURS OF OPERATION	COMMENTS
			FT. X FT. X FT.				(F.C.)	(HRS)	
COL (1)	COL (2)	COL (3)	COL (4)	COL (5)	COL (6)		COL (7)	COL (8)	COL (9)
			L x W x H		LUMINAIRE STYLE				
					LAMP NOMEN.				
					DIFFUSER				
			L x W x H		LUMINAIRE STYLE				
					LAMP NOMEN.				
					DIFFUSER				
			L x W x H		LUMINAIRE STYLE				
					LAMP NOMEN.				
					DIFFUSER				
			L x W x H		LUMINAIRE STYLE				
					LAMP NOMEN.				
					DIFFUSER				

The number of each type of luminaire serving the space is recorded in Column 5. The luminaire type is described in Column 6. For each luminaire, describe the fixture type (e.g., recessed, suspended), the diffuser type, and the type of lamp (e.g., wattage, incandescent, fluorescent).

Measured light levels are recorded in Column 7. The annual hours of use of each area's luminaires are recorded in Column 8. Any additional information may be recorded in the last column, Column 9.

Observed light levels can be measured with a **photometer.** This device operates on the photoelectric effect, whereby the intensity of certain wavelengths of light on certain materials causes a proportional voltage to be generated. A photometer incorporating a digital readout is illustrated in Exhibit 9.30.

The photometer provides a direct readout of light intensity, measured in foot-candles. Measurements are taken by positioning the photometer at the point where tasks are performed. For instance, readings in an office would be taken on desktops. In a plant, the readings would be taken at an operator's station or at a critical location adjacent to a machine. When using the photometer, the energy auditor must avoid shading the sensor with his own body.

Suggested illumination levels for various tasks are presented in Exhibit 9.31.

Exhibit 9.30

DIGITAL PHOTOMETER

Exhibit 9.31

SUGGESTED LIGHT LEVELS FOR VARIOUS TASKS

TYPE, OCCUPANCY & AREA	FOOTCANDLES (MIN.-MAX.)
PROCESSING AND MANUFACTURING	
Bulk Unloading	30
General Process Equipment Areas	50
Mixing, Weighing, & Blending, Processing Bins & Tanks, Equipment Rooms	30
Refrigeration Compressors, Fans, Pumps & Air Compressors, Freezer Tunnels	5
Palletizing Equipment Area	30
Cleaning, Grading & Inspection of Raw Materials	70
Preliminary Sorting, Cutting Final Sorting, Inspection	100
Color Inspection & Appraisal	100-200
Machine Composition, Composing Room & Presses	100
Loading, Rail & Truck	20
Inside Truck Bodies & Freight Cars	10
PACKAGING	
Filling, Labeling, Packing, Wrapping	50
STORAGE	
Rough Bulky (spare equipment)	10
Medium (spare parts)	20
Fine (bins & racks)	50
Picking Stock, Classifying	30
WAREHOUSES	
DSSD Warehouse	15-25
Cold Storage Warehouse	

TYPE, OCCUPANCY & AREA	FOOTCANDLES (MIN.-MAX.)
UTILITY	
Boiler Plants, Compressors, Pump Rooms, Auxiliaries Condensers, Deaerator, Evaporator, Heater, Floors	30
Control Panels	50
Utility Tunnels	5
Cooling Tower	5
MAINTENANCE SHOP	
All Work Areas	50
LABORATORIES	
All Work Areas	100
ELECTRICAL EQUIPMENT & INSTRUMENT	
Switchgear, Indoor, Unit Substations	20
Motor Control Center, Central Control Room	
Aisle Lighting	50
Instrument & Repair Shop	100
OFFICE	
General Office	70-100
Private Office, Conference Room	70
Data Processing & Teletype	150
Drafting Rooms	150
Telephone Switchboard	50
Reception	30
Library - General	30
Reading Rooms	70
Rest, Toilet, & Locker Rooms	30
Aisles, Corridors & Stairways	20
Product Display Area	100
Night Lighting (Security)	1

SESSION 10: DATA ANALYSIS

The two preceding sessions described the preliminary and detailed energy audit process (Session 8) and the use of instruments to measure energy and material flow characteristics (Session 9). At this point, the major energy-using processes and operations are identified, and measurements of energy and material flows are available. This session will describe the most important tool used in industrial energy auditing, the energy balance. Next, the use of energy balances to evaluate energy efficiency will be covered. Finally, energy consumption norms and standards will be discussed. From norms and energy balances established by the industrial audit, it is possible to estimate energy savings potential and identify candidate projects for further evaluation.

THE ENERGY BALANCE

The energy balance is basically the global equation(s) that translates the principle of conservation of energy (first law of thermodynamics) applicable to a given operation, process, plant, sector, or even country or group of countries. Although energy balances can also be created according to the second law of thermodynamics, in entropy or any other thermodynamic state, we will concentrate this session on the enthalpy balance (first law) which is generally sufficient when dealing with industrial energy auditing and conservation.

The basic energy balance equation is:

$$\text{Heat in} + \text{work in} = \text{heat out} + \text{work out.}$$

The energy balance is a useful guide to the efficient operation of process plant and other industrial equipment. Its final objective may be to indicate the scope for energy conservation, as its value is in identifying and evaluating the ways in which energy is consumed in each step of the process.

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Energy balances are generally built:

1. To evaluate losses and inefficiencies in operation of existing plant and equipment
2. To evaluate the energy use in each process stage for comparison with an alternative system or known energy consumption.

The first evaluation often results in identifying improvements in the efficiency of existing equipment by operational changes (no or low capital expenditure). The second evaluation is used when a comparison is to be made with a new plant or system, and is usually associated with large capital expenditure projects.

The data given in this session will assist in the formulation of procedures for building energy balances and identifying areas for energy use improvements. In building energy balances, a detailed knowledge of the process operations is essential in determining the type of measurements to be taken and their interpretation.

Energy balances are multiform and may answer a large variety of questions, such as:

- How much heat is currently used to dry a given product, and what would be the minimum theoretical requirement for this operation? By taking the right measurements (e.g., mass flows, temperatures of product in, product out, drying air in, drying air out, dryer surface) and using the right tools (such as steam table or psychrometric charts; see Session 4), it is possible to answer these two questions.
- What would be the optimum amount (from an energy consumption standpoint) of cooling water required to reduce the temperature of a hot organic liquid stream from T_2 to T_1? By knowing the characteristics of the heat exchanger (heat transfer coefficients and available heat transfer surface area), organic liquid flow rate, specific heats, and temperature, it is simple to determine this optimum value for the cooling water flow.

Providing answers to such questions often raises other questions. In the above examples, the following questions could be asked:

1. Could the initial moisture content of the product to be dried be reduced before processing?
2. What is the amount of heat being transferred from the organic liquid to the cooling water, and can this heat be used elsewhere in the manufacturing operation?

Building an Energy Balance

The **first step** is to identify the subject of the energy balance. For reasons of simplicity, we will assume that energy balances must be established for each major energy-using piece of equipment as identified during the audit (see Session 8) (i.e., boilers, steam systems, furnaces, kilns, ovens, dryers, large mechanical systems, air conditioning systems, and lighting). The **second step** is to identify what is needed to build the required energy balance; that is:

- Identify all operations in which energy (heat or work) is either introduced or removed from the balance object
- Identify each input and output energy stream.

The **third step** is to gather the data necessary to build the balance. Some data may already be available; some may never have been gathered. In any case, it is highly recommended to make **all required instrumented measurements** within as short a period of time as possible, which must be as close as possible to "normal operation," although this concept may be hard to define in some cases. For example, if the object of the energy balance is a furnace, the following measurements should be made: product flow and temperature, combustion product composition, flue gas composition and temperature, combustion air temperature, furnace surface temperature, and mechanical equipment electric consumption (e.g., fans, drive). The appropriate instruments should be selected according to the guidelines provided in Session 9.

When all data have been collected, the energy balance building process can start. To illustrate how energy balances are built, we will use three examples.

Example 1: Heat Balance for a Heat Exchanger

In the case of the shell-and-tube heat exchanger, construction of a heat balance is relatively simple (see Exhibit 10.1). In this example, water is being used to cool an organic liquid, benzene, which is entering the exchanger at 90°C and a flow rate of 100 m^3/hr. The heat lost by the hot benzene equals the heat gained by the cool water, plus any heat that might be lost via convection to the surroundings. The fundamental equation for determining the heat gained or lost by a fluid stream is:

$$q = mC_p dt$$

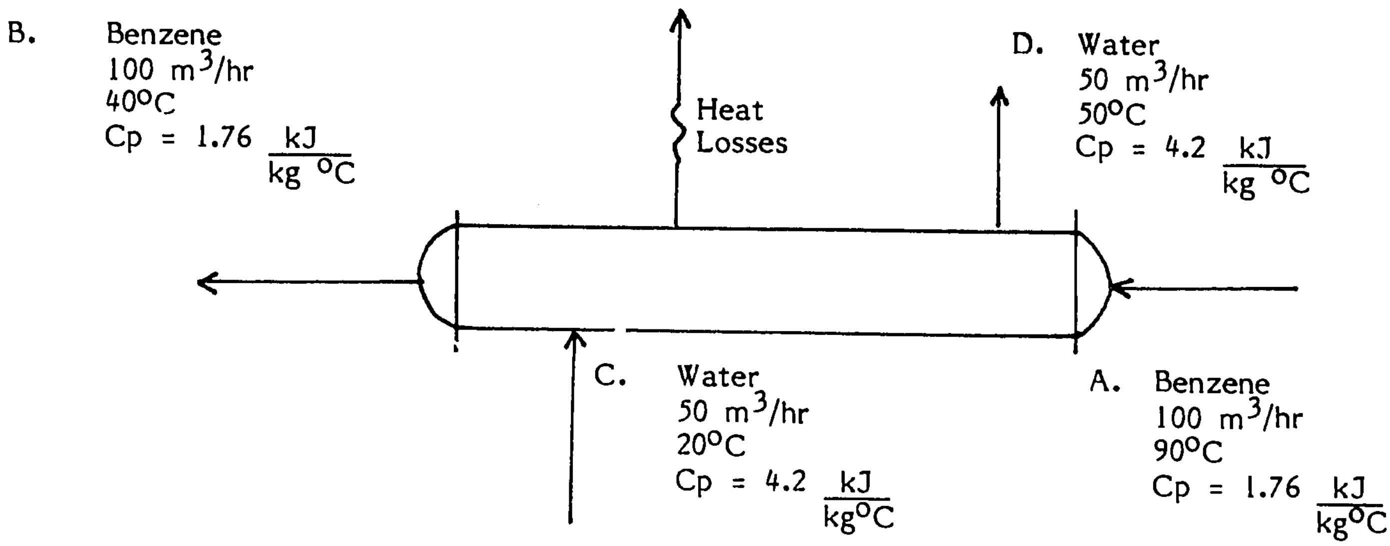
where q = the heat gained or lost (kJ/hr)
m = the mass flow rate (kg/hr)
C_p = the specific heat (kJ/kg °C)
dt = the difference in inlet and outlet fluid temperatures (°C).

For the sake of simplicity, the fluid density and specific heat are assumed constant over the temperatures involved. The heat balance indicates that roughly 81 percent of the heat transferred by the hot benzene is captured by the cooling water. The remaining 19 percent of the heat is lost to the surroundings. (Heat exchangers are discussed in more details in Session 14.)

Example 2: Hot Water System in a Textile Plant

A second example shows how the use of a simple heat balance and the addition of two exchangers to capture waste heat led to improved energy efficiency in a textile plant. This plant produces and finishes woven apparel fabric. The plant operates 24 hours per day, 6 days per week, 51 weeks per year. The wet processing operations at the plant are batch and continuous washing and jet dyeing. The combined wastewater discharge from these operations is 128 m^3 per hour at an average temperature of 60°C. The original operation of the plant called for this water to be discharged to a drain (see Exhibit 10.2).

Exhibit 10.1
Shell-and-Tube Heat Exchangers



<u>Heat Balance</u>

q	=	m Cp dt		
q (Benzene)	=	q (Water)	+	q (Losses)
m Cp dt	=	m Cp dt	+	qL

qb:

$(100\ m^3/hr) \times (879\ kg/m^3) \times (1.76\ kJ/kg^oC) \times (90^oC - 40^oC) = 7.74 \times 10^6\ kJ/hr$

qw:

$(50\ m^3/hr) \times (1{,}000\ kg/m^3) \times (4.2\ kJ/kg\ ^oC) \times (50^oC - 20^oC) = 6.3 \times 10^6\ kJ/hr$

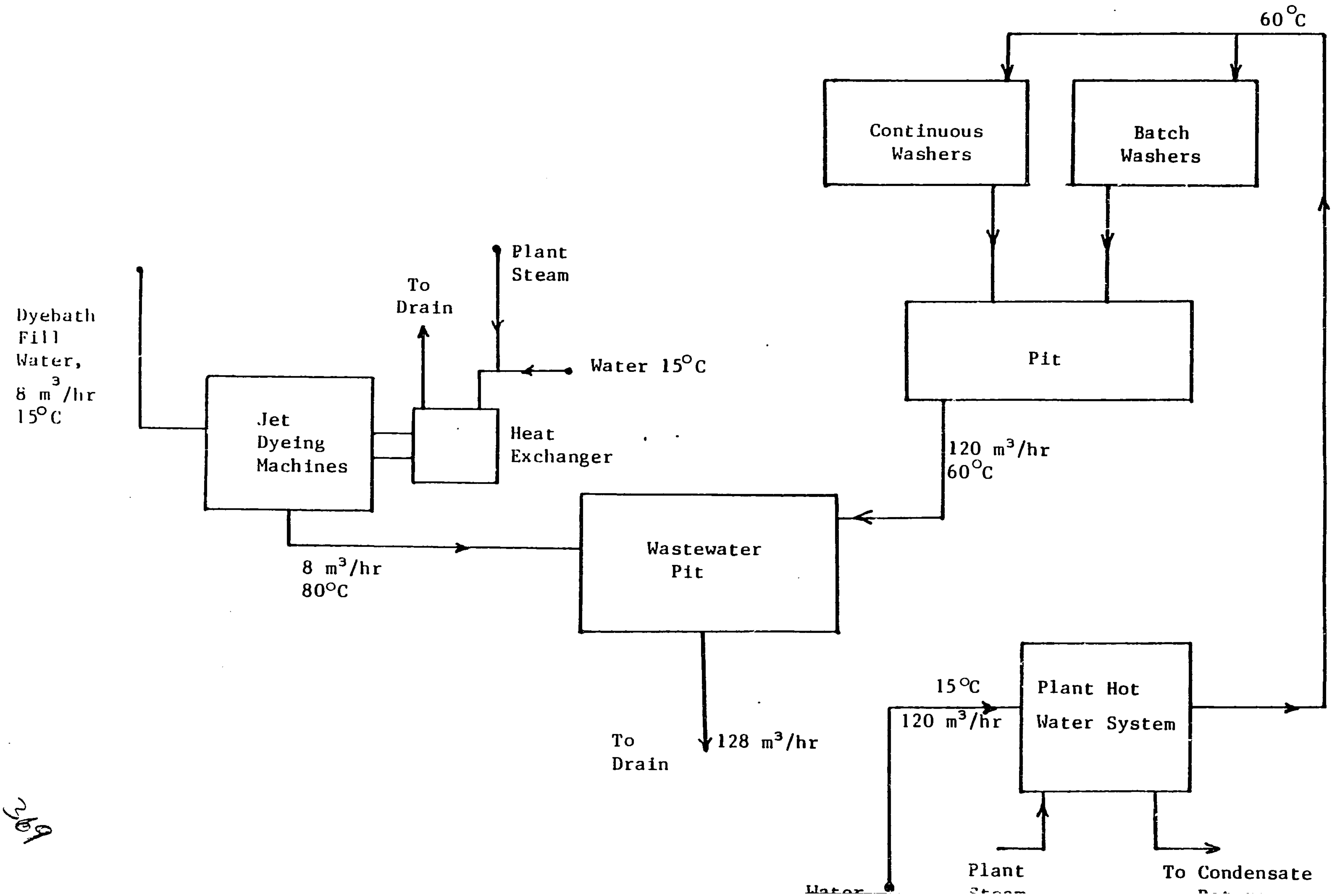
qL:

qL = qb - qw

$(7.74 \times 10^6\ kJ/hr) - (6.3 \times 10^6\ kJ/hr) = 1.44 \times 10^6\ kJ/hr$

Exhibit 10.2

Textile Plant Energy Balance



The jet dyeing machines are heated and cooled by means of an adjacent heat exchanger. During the heating cycle, steam passes through one side of the heat exchanger, and the dyebath flows at a daily average of 8 m^3/hr until its temperature reaches 100°C through the other side. During the cooling cycle, 12 m^3 per hour of filtered water flow opposite the dyebath. The cooling water is heated from 15°C to 50°C during this process.

The batch and continuous washers discharge wastewater at an average rate of 120 m^3 per hour at 60°C. The jet dyeing machines discharge wastewater at an average rate of 8 m^3 per hour at 80°C.

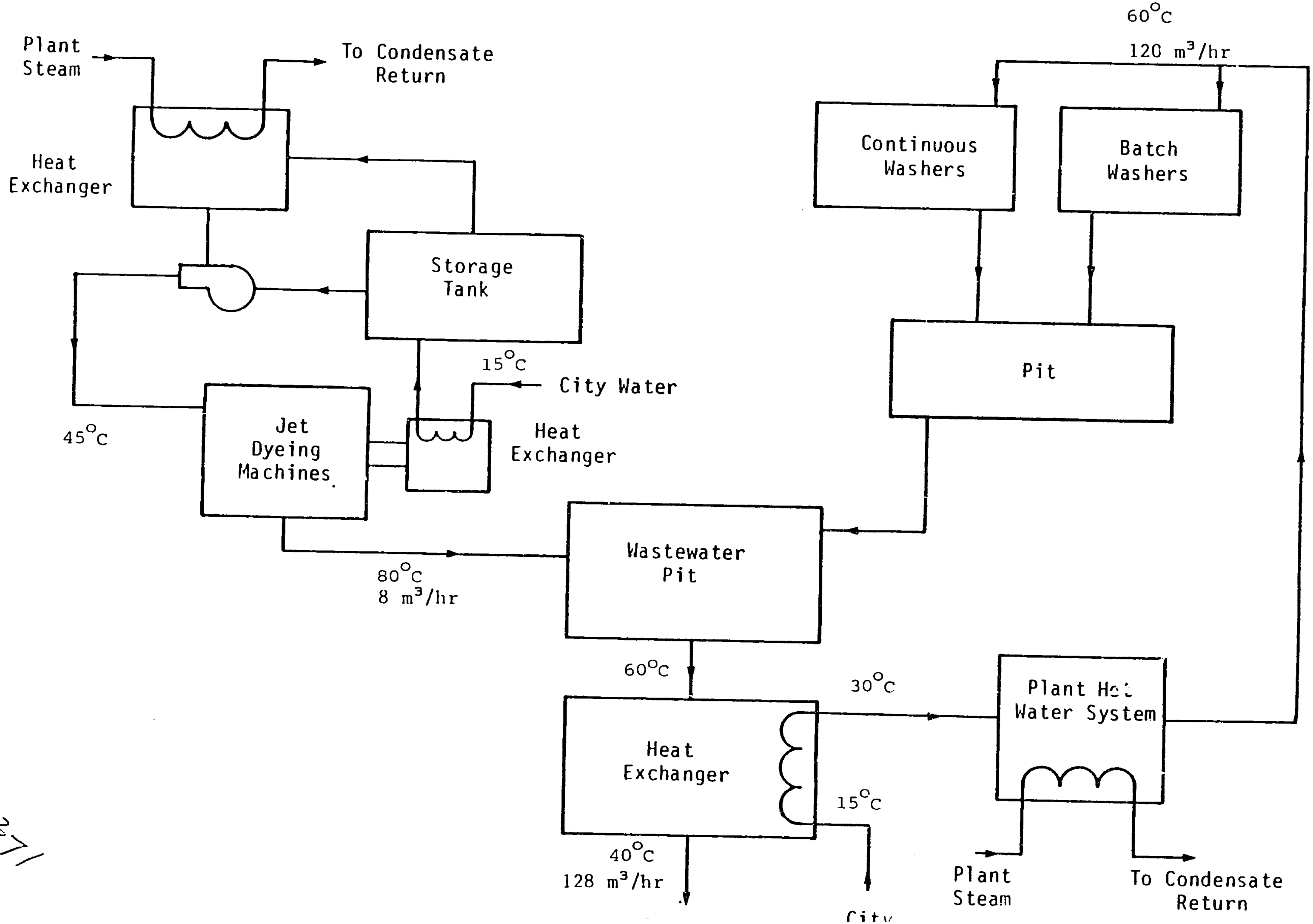
A rudimentary heat balance around the entire process shows that there is clearly room for energy improvement in this process. The energy efficiency of this operation can be improved significantly by introducing a wastewater heat recovery system (see Exhibit 10.3). Wastewater from the jet dyeing machines, batch washers, and continuous washers is piped into a collection system. From there, the water is pumped through a shell-and-tube heat exchanger, reducing its temperature from 60°C to 40°C. The wastewater is then discharged to the process drain. Incoming filtered water at an average temperature of 15°C is passed through the opposite side of the heat exchanger, exiting at an average temperature of 30°C.

A second integrated loop of the waste heat recovery system uses thermal energy rejected from the dyebaths during the cool-down cycle. Cooling water at 15°C is circulated through one side of the closed heat exchanger attached to the jet dyeing machines. The hot dyebath, at a temperature of 100°C, flows continually through the opposite side of the heat exchanger until the temperature is reduced to 80°C. The dyebath is then discharged to the wastewater collection sump. The cooling water is raised to an average temperature of 50°C, even though fresh water is being added constantly to the heat exchanger. Approximately 4.73 m^3 of cold water are required to cool each dyebath from 100°C to 80°C.

The cooling water is collected in a storage tank. Hot water circulating pumps draw from the storage vessel and circulate water either directly into the plant hot water systems or back into the jet machines as dyebath fill water, as required. A separate heat exchanger sub-loop is also provided to maintain the temperature of the water in

Exhibit 10.3

WASTEWATER HEAT RECOVERY SYSTEM



storage by using the plant steam supply. Hot water from storage and tempered water from the low-temperature system can be mixed, if necessary, to meet temperature requirements prior to return to the plant hot water system.

Introduction of the wastewater recovery system reduces steam requirements by 33 percent, from 25.54 GJ/hr to 16.97 GJ/hr (see Exhibit 10.4).

Example 3: Cake Baking

A good example of the use of a heat balance in a low-temperature process is the baking of cakes. The cake-baking process is direct and simple. An electric oven is used, with the cake being continuously circulated through the oven on reusable steel trays. Each steel tray weighs 15 kg and holds four 0.5 kg cakes. Twelve trays and 48 cakes go through the 10-kW oven every hour. The cake is baked when the dough temperature reaches 150°C.

The dimensions of the oven are 1 m by 3 m by 4 m; during operation, its surface temperature is 30°C (room temperature is 20°C). The specific heat of the dough is known to be 3.34 kJ/kg °C.

The process energy balance takes into account heat losses to the surroundings, the heat required to bake the cake and heat the steel trays, and an estimated air change once every hour (see Exhibit 10.5). These results show two important energy inefficiencies in the process: the amount of energy required to heat the steel tray and the energy losses are too large. The overall efficiency of the process -- that is, the heat used to bake the cake divided by the energy input -- is only 36 percent. Improvements to the process can be made by reducing the weight (but maintaining the strength) of the steel trays, insulating the oven, and reducing the number of air changes in the process. It should be noted that the loss of moisture in the dough during the baking process was not considered in this example, but could be an important consideration.

Exhibit 10.4
Calculations for Textile Plant

Steam input to original plant:

For batch and continuous washers:

$$q = (120\ m^3/hr) \times (1{,}000\ kg/m^3) \times (4.2\ kJ/kg\ ^oC) \times (60^oC - 15^oC) \times 10^{-6}$$
$$= 22.68\ GJ/hr.$$

For jet dyeing machines:

$$q = (1{,}000\ kg/m^3) \times (8\ m^3/hr) \times (4.2\ kJ/kg\ ^oC) \times (100^oC - 15^oC) \times 10^{-6}$$
$$= 2.86\ GJ/hr.$$

Total steam input = 25.54 GJ/hr (assuming no heat losses) to original plant.

Steam input to plant after addition of waste heat recovery system:

For batch and continuous washers:

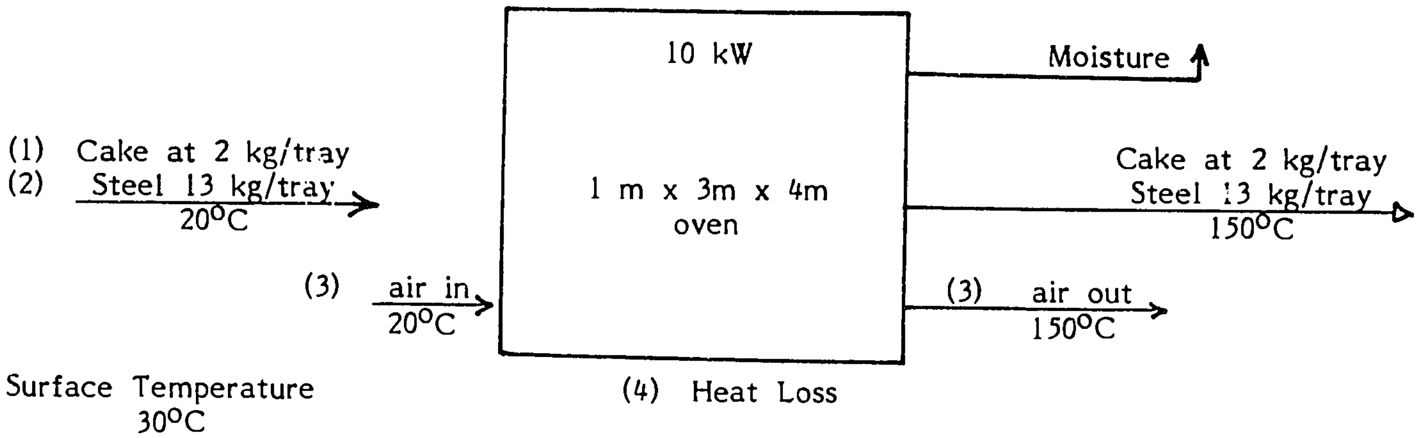
$$q = (120\ m^3/hr) \times (1{,}000\ kg/m^3) \times (4.2\ kJ/kg\ ^oC) \times (60^oC - 30^oC) \times 10^{-6}$$
$$= 15.12\ GJ/hr.$$

For jet dyeing machines:

$$q = (8\ m^3/hr) \times (1{,}000\ kg/m^3) \times (4.2\ kJ/kg\ ^oC) \times (100^oC - 45^oC) \times 10^{-6}$$
$$= 1.85\ GJ/hr.$$

Total steam input = 16.97 GJ/hr after addition of waste heat recovery equipment.

Exhibit 10.5
Energy Balance of a Cake-Baking Oven



A. Energy in:

Electricity 10 kW = 36,000 kJ/hr.

B. Energy out:

Notes	Step	
1	Cake = (0.5 kg/cake) x (4 cake/tray) x (12 trays/hr) x (3.34 kJ/kg °C) x (150°C - 20°C)	= 10,421 kJ/hr
2	Steel = (15 kg/tray) x (12 tray/hr) x (0.46 kJ/kg °C) x (150°C - 20°C)	= 10,759 kJ/hr
3	Air = (12 m^3) x (1 airchange/hr) x (1.18 kg/m^3) x (1.0 kJ/kg °C) x (150°C - 20°C)	= 1,847 kJ/hr
4	Heat loss = (41.8 kJ/hr m^2 °C) x (26 m^2) x (30°C - 20°C)	= 10,868 kJ/hr
	Total	33,895 kJ/hr

C. Energy balance = energy in - energy out = 36,000 kJ/hr - 33,895 kJ/hr = 2,105 kJ/hr (5.9%).

Notes

1. Assumes a constant cake weight and specific heat.
2. Assumes specific heat of steel is 0.46 kJ/kg °C.
3. Assumes one air change per hour.
4. Assumes a heat transfer coefficient of 41.8 kJ/hr m^2 °C. The oven has an external surface area of 26 m2.

Finalizing the Energy Balance

The first balance built from measurements, or preliminary balance, must be validated, which is in fact rather simple; the basic equation (energy in = energy out) must be satisfied by computing independently each member of the left and the right side of the equation. If this is done honestly (do <u>not</u> compute a term of this equation by using differences!!), and the balance is within 1 or 2 percent, the balance can be considered as valuable.

However, it may happen that incorrect computations or measurements compensate each other and still allow the basic equation to be balanced. To ensure that this is not the case, expertise and experience are required.

In most cases, however, common sense is enough to indicate if something is wrong in the computation. Another, more expensive way, to validate and check the accuracy of an energy balance is to have it done by two different individuals at different dates but under similar conditions. This would be justified in extreme cases only (i.e., when the balance cannot be established the first time, -- 10 percent difference or more) or when common sense cannot be satisfied by the results.

The Use of the Energy Balance

Energy balances are primarily used to evaluate energy efficiencies as illustrated in the examples above. From the energy balance of a boiler, the following efficiencies can be computed:

- Combustion efficiency
- Heat to steam efficiency
- Overall boiler efficiency.

Sessions 2, 4, and 11 through 14 provide detailed information on the concepts of efficiency and their application to major energy-using equipment.

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ESTIMATING ENERGY CONSERVATION POTENTIAL

The efficiency computations are the basis for estimating energy-saving potential. The basic method is to compare the efficiency computed from the balance to what a good performance should be. Such a performance is often referred to as a "norm" or a "standard." For example, a 50-tsh, 45 bar watertube boiler operating at 80 percent of its rated capacity and burning furnace oil should have an efficiency of 82-84 percent. If the balances gives an efficiency of 79 percent, 3 to 5 percentage points translate into 4 to 6 percent potential fuel savings. However, norms and standards are not easy to find or to establish. Such a norm can be established for a given piece of equipment (e.g., a boiler, a dryer, an electric motor), a given operation (e.g., drying in a cement kiln), or a given product (e.g., raw steel). In the case of drying, the norm can be either 2,508 kJ/kg of water evaporated (theoretical minimum) or 3,135 kJ/kg of water evaporated (good average performance). In the case of steel, the theoretical consumption is 7.1 GJ/ton, and a good performance is 25.1 GJ/ton. Both numbers can be used as norms, as most plants in LDCs consume between 33.4 and 50.2 GJ/ton.

There is no such thing as a "directory" of norms. Rather, technical manuals and equipment suppliers' brochures should be used to define them. In addition, norms are not fixed nor constant over time and across processes. They must take into account such factors as actual operating procedures and technological evaluations.

Microcomputer applications software ready for energy engineering

Several software packages designed specifically for engineers involved in steam-generation-system design and analysis have recently become available through Software Systems Corp, based in Austin, Tex. Programs are available for the IBM personal computer, the Texas Instruments professional computer, and all IBM PC-compatible computers. The software programs can be applied in:

- Economic analysis of energy-conservation projects.
- Estimation of heat losses from insulated and uninsulated surfaces.
- Determination of pressure-loss and pumping-power requirements for piping systems.
- Analysis of industrial cogeneration systems.
- Analysis of combustion-equipment efficiency.

Following is a summary of each program and its cost:

Datafit: Performs a regression analysis on user-supplied data to determine the best-fit equation for each of seven different types of distributions: exponential, square root, power, inverse, linear, logarithmic, polynomial. Program analyzes data sets as large as 500 points and allows users to perform any number of interpolations. Datafit costs $245.

Steamcalc: Computes individual values of thermodynamic steam properties, over a wide range of temperatures and pressures, for subcooled, saturated, and superheated conditions. Equations contained in the program are an adaptation of those recommended by the American Society of Mechanical Engineers (ASME), and produce thermodynamic values that agree closely with ASME steam tables. Steamcalc costs $245.

```
                    COMBUSTION ANALYSIS RESULTS

------------------------- BASIC COMBUSTION DATA -------------------------
Fuel type:              Coal            Relative humidity:          60.00 %
Heating value:          12,800 BTU/lb   % Combustible in refuse:    10.60 %
Stack temperature:      345.0 deg F     Fuel analysis:              User-supplied
Ambient temperature:     90.0 deg F     Percent excess air:         19.27 %

FUEL ANALYSIS (Coal):                        FLUE GAS ANALYSIS:

 Element     % by weight                         Element           % by volume
 ---------   -----------                   -------------------    -----------
 Carbon:        72                         Carbon Dioxide:            15.2
 Hydrogen:      4.4                        Oxygen:                     3.6
 Oxygen:        3.6                        Carbon Monoxide:             .3
 Sulfur:        1.6                        Nitrogen:                  80.9
 Nitrogen:      1.4
 Water:         8
 Ash:           9

-------------------------- FUEL INPUT SUMMARY ---------------------------

                 Pounds per million                   Pounds per million
                 BTU's of fuel fired                  BTU's of fuel fired
                 -------------------                  -------------------
      Carbon:          56.25           Hydrogen:          3.44
      Oxygen:           2.81           Nitrogen:          1.09
      Sulfur:           1.25           Water:             6.25
      Ash:              7.03
                                       Dry air:         986.37
                                       Water in air:     11.63

--------------------------- FLUE GAS SUMMARY ----------------------------

                   Pounds per million                     Pounds per million
                   BTU's of fuel fired                    BTU's of fuel fired
                   -------------------                    -------------------
  Carbon dioxide:       199.26         Sulfur dioxide:           2.50
  Oxygen:                33.19         Nitrogen:               677.11
  Water:                 48.82         Carbon monoxide:          2.50

                                       Total dry flue gas:     914.56
                                       Total wet flue gas:     963.38
                                       Percent moisture:         5.07 %
                                       Combustible in ash:       0.33

---------------------- STACK & COMBUSTIBLE LOSSES -----------------------

                                         BTU's per million
          Heat Loss Category             BTU's of fuel fired
      ------------------------------     -------------------
      Dry flue gas:                            59.486
      Water in flue gas:                       44.617
      Carbon monoxide in flue gas:             10.463
                                             ----------
        Total loss in flue gas:               114.566
      Carbon in ash:                           11.755
                                             ----------
         Total heat loss:                     126.321   Efficiency=  87.37 %
```

Combustion: Computes combustion efficiency of industrial and utility boilers based on the molal method, patterned after standard ASME performance test codes for combustion testing. Combustion systems using all standard fuels can be handled, and those using special fuels (such as woodwastes or other industrial byproducts) can also be handled by entering their specific chemical and thermal characteristics. This program provides the user with an option of several levels of detail in the output report, ranging from simple mass balance to a complete report detailing all energy losses (figure). Flue-gas losses are listed with both sensible- and latent-heat-loss components, as well as losses associated with unburned combustibles. Combustion costs $490.

Heatflo: Computes heat losses from pipes and other surfaces. Program uses accepted engineering procedures for determining convective and radiative heat losses. Correlations of thermal conductivity as a function of temperature have been incorporated into the program for five types of commercial insulation: calcium silicate, fiberglass, polyurethane, mineral fiber, and cellular glass. Heatflo costs $370.

Fuidflo: Computes the pressure loss and power consumption for a series of up to 70 sections of pipe. The Darcy-Weisbach pressure-loss equation is employed, and the Colebrook equation is used to compute friction factors. Fluidflo costs $330.

Cogen: Performs a thermodynamic and financial analysis to evaluate the economic benefits of installing an in-plant cogeneration system. It is designed to be used as a tool for determining the optimum-size turbine/generator for the energy-demand characteristics of the plant. Cogen costs $735.

For more information, circle number **261** on the Reader Service Card. – Software Systems Corp.

Reprinted from
Power, August 1983

SESSION 11: COMBUSTION EQUIPMENT AND BOILERS

INTRODUCTION

This session will focus on the use of combustion equipment (burners) and boilers. Various types of burners will be presented, together with housekeeping measures designed to maintain efficient operation.

Common types of boilers and their operation will be reviewed, together with outlines for housekeeping steps for optimum performance. Modifications and improvements through equipment replacement will be discussed.

The basic functions of a burner were reviewed in Session 4 and hence will not be repeated in this session. The session will concentrate primarily on oil burners, with reference to gas and solid fuel burners (solid fuel burners are presented in more detail in Session 15). Mention will be made of a developing technology, the fluidized-bed combustor, which has good potential for maximizing energy release from solid fuels. Firetube and watertube steam boilers will be covered in some detail. Finally, costs and benefits of typical conservation measures will be presented.

BURNER TYPES

Burners evolved because of the combustion characteristics of various available fuels and the widely differing equipment on which burners are used. Improvements in efficiency and operation have been spurred by competitiveness between the major fossil fuels and anti-pollution laws enacted in the major industrial nations of the world.

Different types of burners are used for combustion of the three major sources of fossil fuel -- oil, solid fuel, and gas. All three types are discussed in the following paragraphs.

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Oil Burners

Oil burners are mechanical devices used to prepare oil for burning in a combustion chamber. Burners deliver the oil in a state that will promote good combustion. Good combustion is aided by intimate mixing of the fuel and combustion air.

A burner may consist of a total packaged unit including associated equipment such as filters, pumps, and fans. However, many large burners consist of only the basic elements that give the burner its individual characteristics.

The basic elements of a burner are:

- Air register
- Atomizer
- Throat
- Stabilizer.

Burners are made up of a combination of these basic elements. Modifications to one or more of these elements can greatly affect the type of flame produced. Because of the relevance of these elements, they are described as opposed to specific burner applications.

Air Registers

There are three broad groups of air registers used in oil burners: (1) the swirling type, (2) the intermediate type, and (3) the axial flow type. Examples of the three types of registers are shown in Exhibit 11.1.

The swirling type of register is used to give the fuel a strong swirl before it passes through the throat of the burner. The swirl-type design produces a strongly divergent flame and promotes central recirculation for good flame stabilization. However, fan power requirements are high with this type of register. They are used primarily where intense short, wide flames are required.

Exhibit 11.1

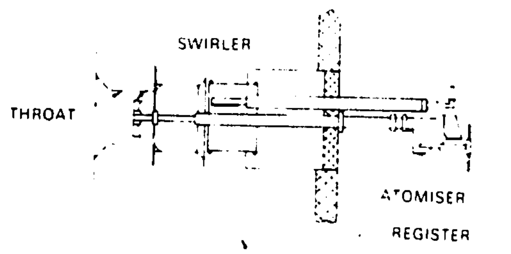
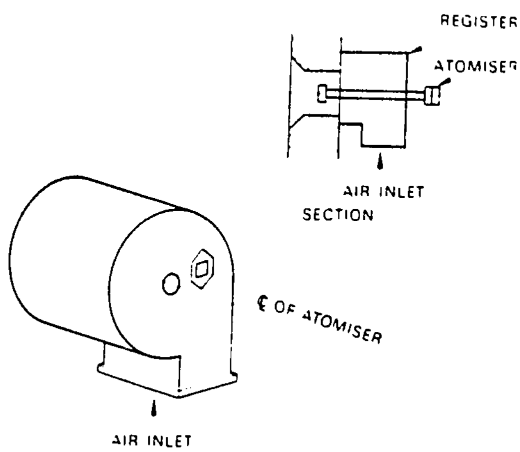
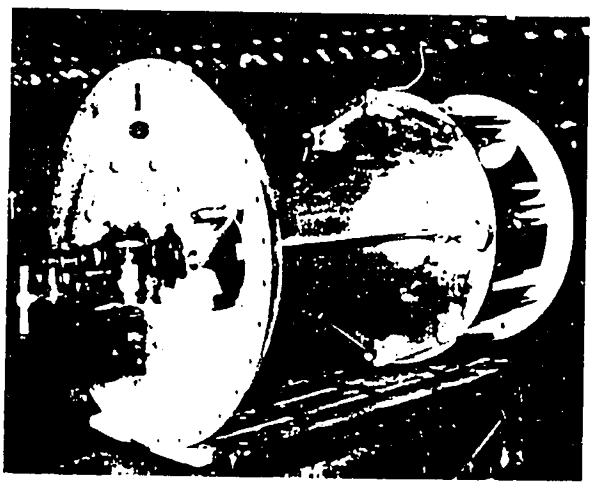


Fig. 1. Section through axial flow burner showing main basic elements register, atomiser, throat, stabiliser.



Swirling type register.

Intermediate swirl type register.



The intermediate type of register was once used universally throughout the burner industry. It is based on a cylinder whose periphery was made up of a series of pivoting slots that could be opened or closed to control the amount of swirl produced with the corresponding change in flame properties.

The axial flow type of register is now the most common type of register used, as it offers the most efficient method of producing required aerodynamic characteristics. In the axial flow register, air is delivered along the same axial path as the fuel travels from the burner atomizer. Air is usually introduced through slots to mix with the fuel. Flame shape and intensity are controlled either by modulating the speed of the combustion air fan or by dampers that affect delivery air pressure and volume. Swirl is imparted to the fuel/air mixture by use of differing types of swirlers.

Atomizers

Oil must be vaporized prior to combustion, and atomizers are used to aid rapid vaporization. Atomizers are the most important element of the burner.

Burners are often distinguished by the type of atomizer that they use. Industrial burners use one of the following atomizing methods:

- Medium-pressure air (MPA)
- Low-pressure air (LPA)
- Spinning or rotary cup
- Pressure jet
- Spill or return flow
- Assisted pressure jet
- Twin fluid atomizer.

Other types of atomizers (e.g., emulsifying or ultrasonic atomizer) are less common and will not be discussed.

The **MPA atomizer** is generally a two-stage atomizer. Atomization is produced from the blast effect of primary air supplied at pressures between 0.2-1 bar (3-15 lbs/ in^2).

Primary air accounts for approximately 5 percent of the combustion air. Further atomization takes place after the oil/air mixture leaves the burner tip. A supply of secondary air from a forced draft fan at a pressure of 1.25-2.5 mbar (0.5-1 inch water gauge) breaks up the fuel still more. This type of atomizer is used predominantly for burners using light fuel oil for firing heating plants and low-pressure steam plants.

LPA atomizers use primary air at pressures of 5-6 mbar (2-2.5 inch water gauge). Primary air accounts for 25 to 30 percent of the overall combustion air. Atomization takes place by swirling primary air causing acceleration of the oil through the atomizer. The primary air/fuel mixture is further accelerated by a secondary air supply. This essentially varies the amount of swirl and controls the flame shape. Complete atomization occurs when fuel passes into a tertiary air supply that enters the burner through air registers. As with the MPA, this type of atomizer is used in burners for small boiler plants firing lighter grades of fuel oil.

The **spinning or rotary cup** atomizer consists of a spinning hollow divergent cone. Oil is distributed evenly onto the inside and travels outward along the spinning cone. In traveling along the cone, the oil film breaks into linear components and droplets and is finally thrown from the tip of the rotating cone. Combustion air passes around the cone and completes the atomization of the fuel. Power to drive the cone is supplied by either motor or air turbine at rates of between 4,000 and 6,000 revolutions per minute. To ensure that correct atomization takes place with this type of atomizer, the oil used should have a viscosity of about 100 centistokes (cSt) (400 sec Redwood No. 1). This type of unit is used predominantly on firetube boiler plants operating with excess air levels of about 10 percent.

In **pressure jet atomizers,** oil is injected at high velocity through tangential slots into a swirl chamber where it rotates at high speed. It then passes through an opening where it forms a hollow conical sheet (see Exhibit 11.2). Combustion air is supplied around the pressure jet. Because of their relatively simple design, pressure jet atomizers are available in a wide range of capacities. They are capable of burning all types of fuel oil.

When burning bunker oil, it is necessary to operate at viscosities ranging between 13 and 24 cSt (60 to 100 Redwood No. 1). Oil flow to the burner is controlled by the operating pressure of the oil supply. Typical pressures may range from 28 to 80 bar

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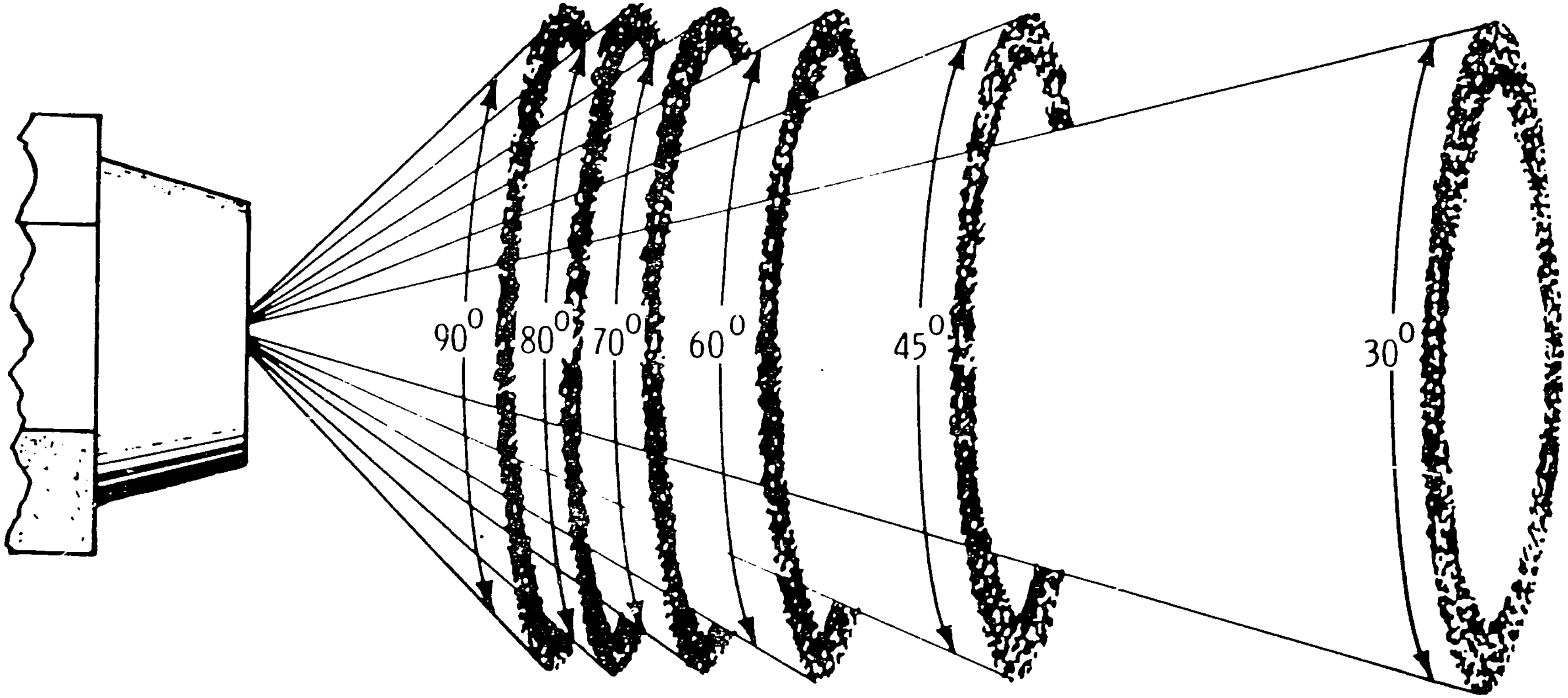
Exhibit 11.2

Courtesy Wayne Home Equipment Co., Inc.

Solid spray cone pattern.



Courtesy Wayne Home Equipment Co., Inc.

Varieties of spray angles.

OIL BURNER AIR SYSTEM

(400 to 1,200 lb/in^2). The typical pressure/quantity relationship for this type of atomizer is shown in Exhibit 11.3.

Spill or return flow atomizers attempt to overcome the drop in performance of pressure jet atomizers at reduced loads. With the pressure jet atomizer, swirl chamber activity is reduced at low load operation, thus reducing the efficiency of the atomizing mechanism. In the spill or return atomizer, oil flow is maintained, thereby sustaining swirl chamber activity at all times. Oil not needed to sustain the prevailing firing rate is circulated (see Exhibit 11.4). Two common methods are used for controlling the rate of spill or return. One system uses a constant supply pressure to the burner. As the spill system closes, total system resistance increases and less oil is fed to the burner. The other system uses a constant volume approach.

Operating viscosities and pressures are similar to those of the pressure jet, but the spillback system increases the range of turndown. Turndown is the relationship between maximum and minimum oil consumption for a given burner. Pressure jets typically have turndown ratios on the order of 1.4 to 1. Spill and return systems have turndowns of about 4 to 1.

The **assisted pressure jet** is essentially a pressure jet tip with a series of atomizing ports arranged to inject steam or air into the root of the fuel spray cone (see Exhibit 11.5). This burner is another attempt to improve the limited turndown capabilities of the pressure jet burner by providing a supplementary atomization medium at low oil pressures. Typical turndown ratios are 4 to 1. These atomizers often use the supplementary atomizing medium throughout the operating range. Operating fuel characteristics are similar to the pressure jet, but maximum oil pressures are usually lower.

Twin fluid atomizers initiate atomization inside a chamber or series of ports within the tip through the combination of oil and steam (see Exhibit 11.6). The oil/steam mixture expands as it leaves the tip, thereby causing atomization. Correct port design ensures high-quality atomization with minimum steam consumption.

Fuel oil viscosities are higher than with pressure jet atomizers, typically 30 to 36 cSt (120 to 150 sec Redwood No. 1). Operating pressures are much lower than pressure jets -- 5.5 to 20 bar (80 to 290 lb/in^2) -- but turndown ratios can be as high as 20 to 1.

Exhibit 11.3

TYPICAL CHARACTERISTIC OF PRESSURE JET ATOMISER TIP.

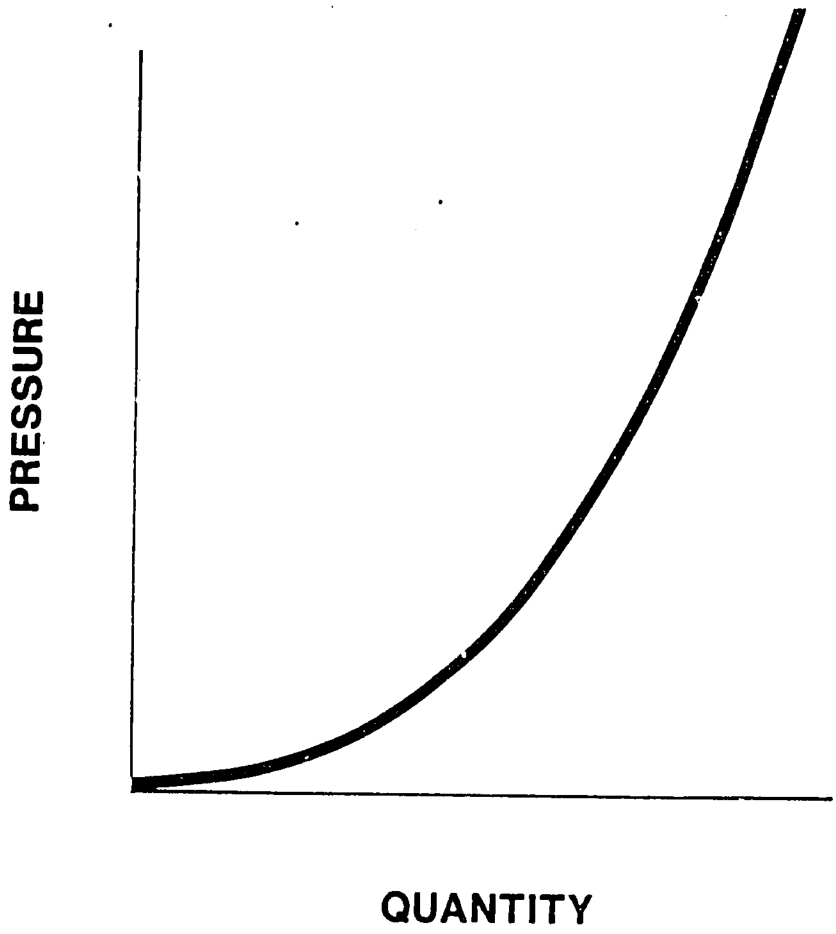
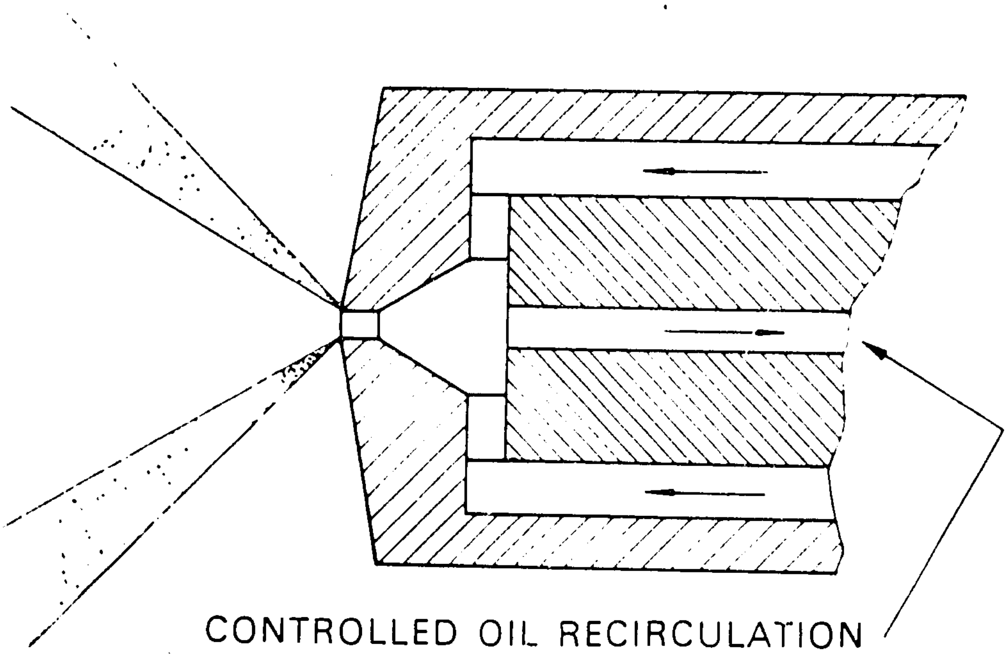
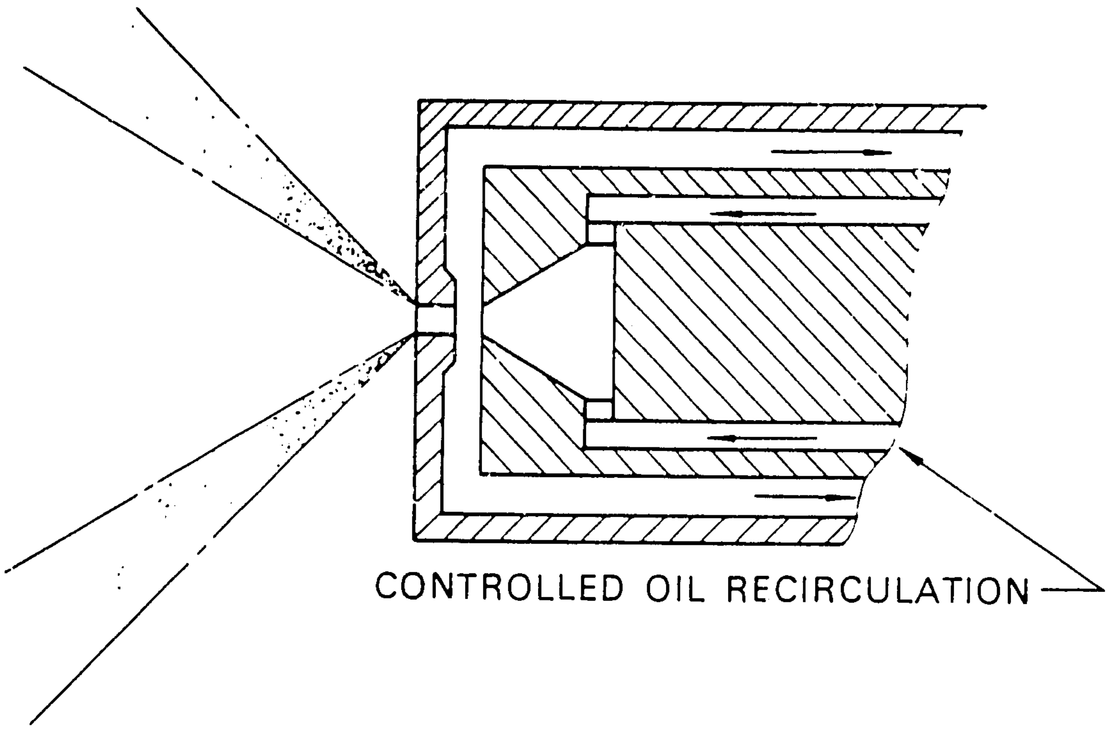


Exhibit 11.4



Spill atomiser tip.



Spill atomiser tip.

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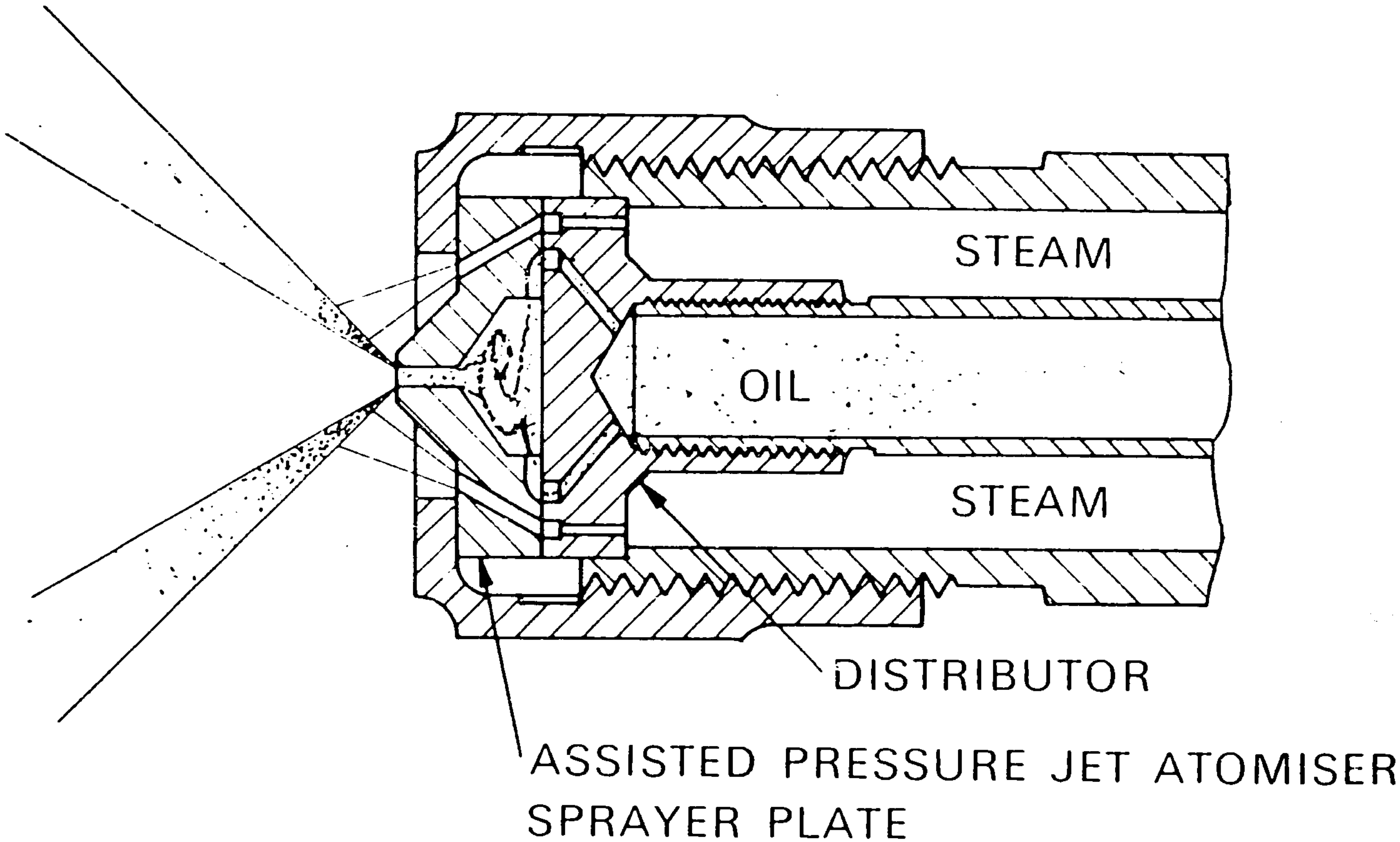
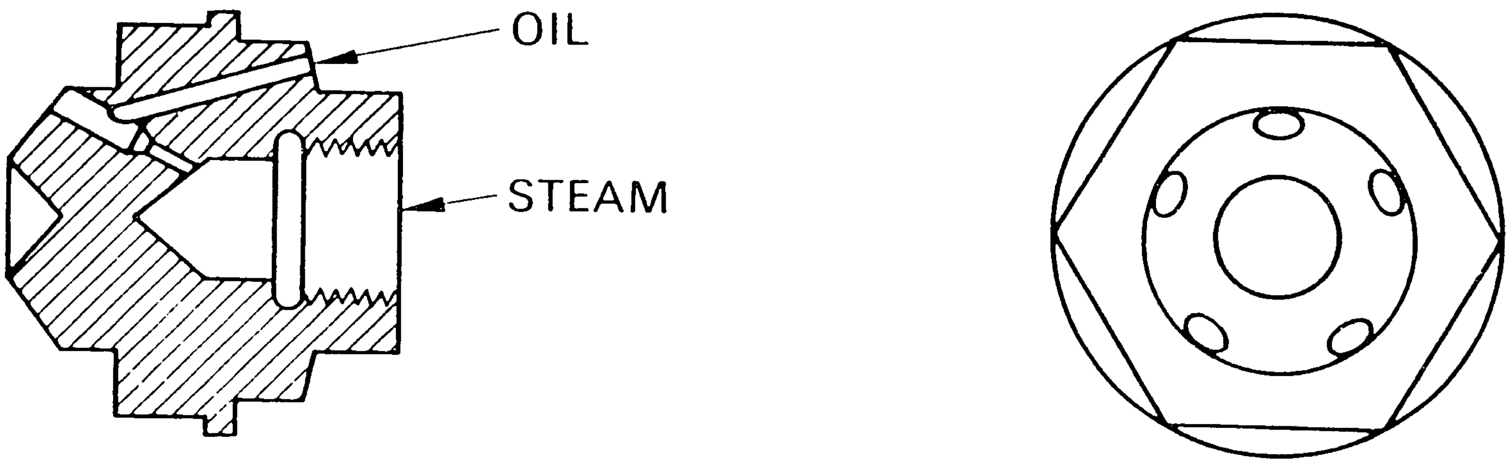
Exhibit 11.5



Section through assisted pressure jet atomiser tip.

Exhibit 11.6



Typical twin fluid sprayer plate.

Throats

The throat of the burner is important in promoting good mixing of fuel and air. It is impossible to generalize about throat design, as the burner throat is basically a chamber whose profile is shaped to produce a desired flame shape. Its design also can increase recirculation, thereby improving fuel air mixing, with corresponding improved combustion.

Stabilizers

The final component of an oil burner is the stabilizer. Stabilizers are used in conjunction with the air register and throat to create the ignition front of a flame. Without a stabilizer, problems may occur with maintaining a constant flame front, causing problems in sustaining ignition. However, burners that operate at very low throat velocities often do not use stabilizers.

Although the four elements categorize burner type, operation is dependent to a great extent on the fuel oil system to deliver oil to the burner in satisfactory condition for combustion. Fuel oil systems vary widely according to the plant served, but because of their relative importance, a brief mention is made in the following paragraphs.

Fuel Oil Systems

There are three common types of fuel oil systems:

- Gravity feed
- Circulating ring main at atomizing temperature
- Circulating ring main at storage temperature.

Gravity feed is used to supply one or two burners. Oil is stored in an overhead tank and fed through gravity alone to the burner. Gravity feed is used with lighter grades of oil that do not require heating for correct atomization.

The other two common types of systems involve the use of a circulating ring main. The difference between the two systems is essentially the operating temperature of the system. The one system maintains oil at atomizing temperature; the other circulates oil at storage temperature.

With the system operating at atomizing temperature, oil from the storage tank passes via outflow heaters to oil pumps and final heaters, where the temperature is raised to atomizing temperature. The heated oil circulates via the ring main from which oil is tapped off to the various burners. Surplus oil is returned to the inlet of the final preheaters.

With the system operating at storage temperature, the oil is pumped and supplied to the burners through heaters that are mounted close to or form an integral part of the burner. The heaters are used to give the temperature required for good atomization characteristics.

Solid Fuel Burners

Solid fuel burners are mechanical devices used to burn solid fuels in a combustion chamber. Solid fuel properties vary more than those of liquid and gaseous fuels, and it is difficult in this session to do more than outline some of the more common types of solid fuel burner.

Solid fuel burners seek to duplicate the requirements of any burner system: mixing fuel and air together so that the combustible matter in the solid fuel (carbon and hydrogen) can combine with oxygen and maximize the amount of heat released.

Solid fuels contain materials other than carbon and hydrogen such as sulfur, chlorine, oxygen, water, and mineral matter of various sorts described collectively as ash. As with liquid fuels, the combustible components must be vaporized or volatilized before combustion takes place. However, the effect of heat on the solid fuel can cause the fuel to swell and retard combustion.

Because solid fuels vary so much, differing types of burners or stokers have developed together with various systems to prepare the solid fuel for combustion. An exhaustive discussion of the properties of solid fuel is beyond the scope of this session, but it is imperative to have the right type of burner for the fuel whenever solid fuel is considered for combustion. **This cannot be emphasized too strongly.** Combustion engineers use solid fuel combustion characteristics as an integral part of designing boilers.

The following paragraphs outline some of the more common types of solid fuel burners or stokers used by industry. To simplify matters, the combustion of one type of solid fuel -- coal -- will be discussed.

Coal

Solid fuel or coal combustion usually takes place on a grate. Three notable exceptions are when coal is burned in suspension (as in a pulverized fuel burner), as a fluidized bed in a fluidized-bed combustor, or as a slurry when mixed with oil or water.

Essential to all types of combustion is combustion air supply. However, because of the need to volatize coal, the amount and timing of air supply is critical to solid fuel firing.

Combustion air is usually referred to as primary, secondary, or tertiary. The term used is dependent on when the air is supplied to the burner. Primary air is usually supplied through the grate bars into a firebed or used to convey pulverized fuel; secondary air is supplied over a firebed or around pulverized fuel. Tertiary air, if used, is supplied after the secondary air to complete combustion. Combustion air is supplied to stokers at pressures and in quantities to create sufficient turbulence to enhance mixing of fuel and air and to shape the flame.

Common types of stokers for coal combustion include:

- Gravity burner
- Underfeed stoker
- Coking stoker

- Chain or traveling grate stoker
- Vekos system
- Octopus system
- Trickle feed stoker
- Pulverized fuel burner
- Fluidized-bed boiler.

These are discussed below.

Gravity feed burners are not mechanical stokers but offer similar efficiencies to mechanical stokers. In the gravity feed burner, fuel gravitates from a hopper onto the fire, where its rate of combustion is regulated by a thermostatically controlled forced draft fan that provides both primary and secondary air. Gravity feed burners are used on a range of equipment from boilers rated at 600 kW through kilns and furnaces up to 750 kW. They are normally used to burn lower grades of coal and anthracite.

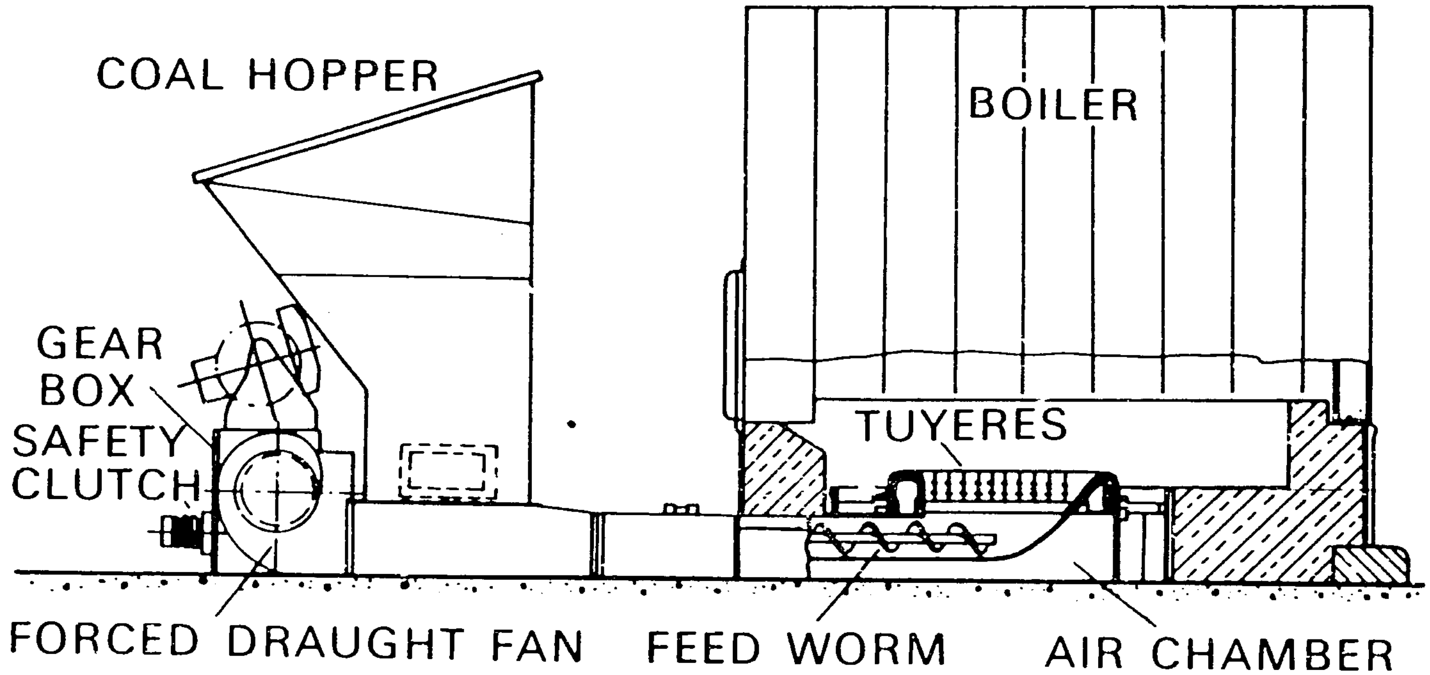
An underfeed stoker is shown in Exhibit 11.7. Combustion takes place at the end of a retort fed with fuel from a hopper or bunker by means of a rotating screw or reciprocating ram. Underfeed stokers are electrically driven, usually by constant speed AC motors; the same motor is used to drive both the forced draft fan and, through a reduction gear, the feed screw. If the screw feed becomes jammed, a shear pin or breaking linkage fails, preventing major mechanical failure.

Air for combustion is supplied by the forced draft fan via tuyeres in the upper part of the retort. The majority of the combustion air is supplied as primary air. Combustion air is regulated at the fan inlet or by damper in the forced draft duct, which in turn is connected to the coal feed regulator to ensure that fuel/air ratios are correct at all times.

Underfeed stokers can be controlled using a simple pressurestat or thermostat to provide on/off control, or as a fully automated modulating system including air/fuel ratio control. Turndown ratios of about 5 to 1 are possible. Underfeed stokers are usually used on small furnaces or boilers. Typical size ranges are 30 kW to 5 MW.

Exhibit 11.7

Underfeed stoker (courtesy Riley (IC) Products Ltd)



A **coking stoker** is shown in Exhibit 11.8. Coking stokers use a flat reciprocating ram to supply fuel to the grate. Fuel is deposited on a coking plate. Some volatile matter is driven off by heat; before fresh fuel falls on the plate, coal is pushed onto the grate, which consists of a series of reciprocating firebars. Through a series of cams, firebars move approximately 75 mm (3 inches), thereby moving the fire along the grate. Then, alternate bars return to their former position, followed within a few seconds by the remaining bars. With correct fuel selection, fuel is completely burned as it reaches the end of the grate, and ash discharged from the grate into an ash pit.

Coking stokers use induced draft to supply combustion air. Primary combustion air is drawn through the firebars. Dampers are often provided to control the amount of air drawn through the firebars. Some secondary air is drawn around the sides and ends of the grate.

Coking stokers are controlled by timer or by automatic combustion controls that regulate either the grate speed or the travel and speed of the feed ram. These stokers are used widely for firetube boilers, small watertube boilers, and kilns. Unit sizes typically range from 0.9 MW to 7.4 MW.

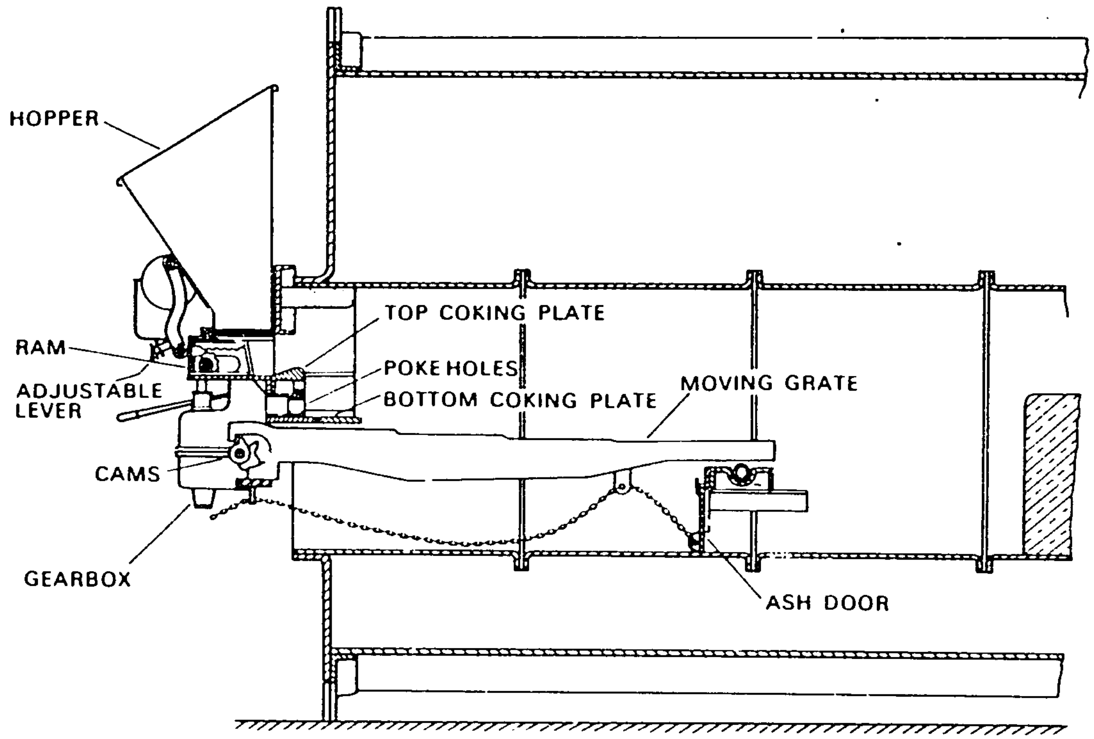
In the **chain or traveling grate stoker**, fuel is fed by gravity from a hopper onto a continuous traveling grate (see Exhibit 11.9). The grate carries the fuel through the furnace, where it burns completely. Residual ash is discharged at the end of the length of travel.

Air for combustion is supplied from a forced draft fan and passes to the underside of the grate, where it rises through the firebed. The relative amount of air is controlled by baffles. Secondary air is supplied over the top of the bed. Ignition of the fresh fuel is aided by the use of a refractory arch that emits radiant heat.

Firebed thickness is controlled by use of a guillotine, and throughput rate is controlled by altering the grate speed. Normal firebed thicknesses range between 100 and 125 mm (4 and 5 inches). Chain grate stokers are widely used for boiler plants and come in a range of sizes, from 90 kW to power station units with boiler ratings of more than 70 MW.

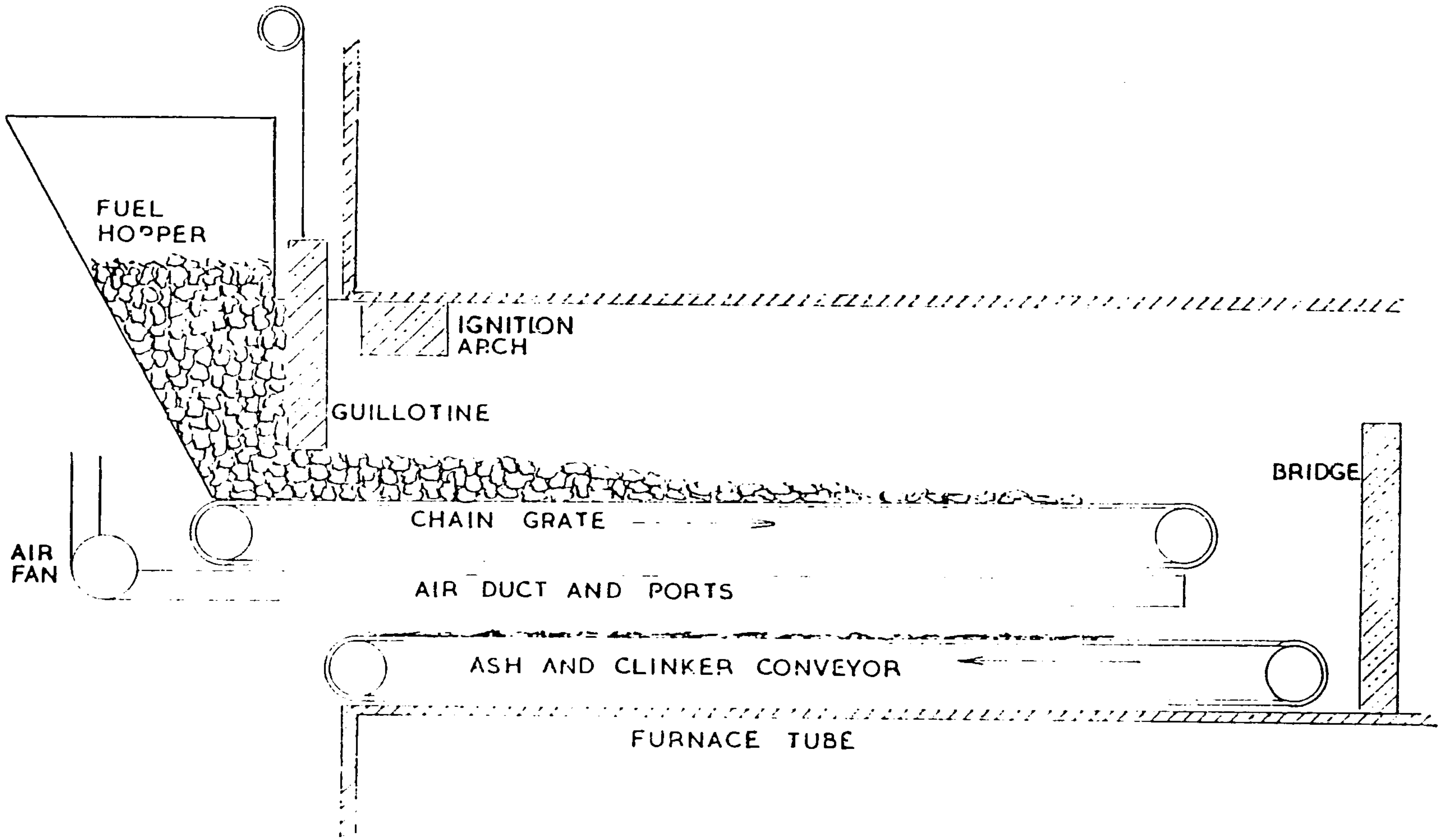
Exhibit 11.8

Coking Stoker



Coking stoker (courtesy Hodgkinson Bennis Ltd)

Exhibit 11.9



CHAINGRATE STOKER WITH ASH CONVEYOR

The **Vekos combustion system** forms an integral part of a Vekos boiler, which is manufactured in a range of outputs from 0.6 MW to 8.5 MW (see Exhibit 11.10). An unusual feature of the Vekos boiler is its multi-fuel capabilities; it can fire a number of solid fuels -- including coal, wood, and waste paper -- as well as oil and gas.

When firing solid fuels, the fuel is fed via a screw conveyor to the crown of the boiler and then falls down a drop tube onto a fixed grate. Fine particles burn in suspension; the remainder of the fuel burns on the fixed grate. Primary combustion air is fed to the grate by a combustion air fan. Secondary air is supplied via the drop tube previously mentioned.

Grit arrestors at the back of the boiler gather any fine particles of coal that are carried away with the exhaust gases. The fines collected are fed via an injector back into the combustion chamber using a supply of tertiary air.

The Vekos system can be automatically controlled by modulating the coal supply and combustion air. If low ash content fuels are used, de-ashing is required only once per day and can be completed in less than 90 seconds.

The **octopus** and **trickle feed systems** were both developed for the heavy clay industry for use on tunnel and continuous chamber kilns. The **octopus system** is so named because of its appearance. Burners are simply lengths of 50-mm (2-inch) diameter steel pipe inserted through holes into the top of the kiln. The number of tubes and their disposition is dependent on the width of the firing zone in the kiln.

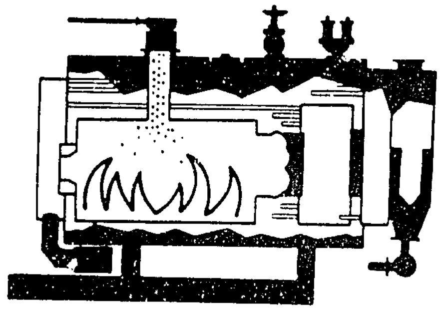
Fuel is supplied to the burners after being prepared in a high-speed pulverizer. Pulverized fuel is stored in a silo, from where it is sent to conveyor pipes. The conveyor pipes contain air that entrains the fuel.

The carrier or primary air represents approximately 5 percent of the combustion air requirements and carries the fuel to the center of a distribution unit. The distribution unit divides the coal/air mixture into a series of separate flows by means of a cone divider or electrically-driven paddle wheel. From there, the fuel flows are directed to the burners.

Exhibit 11.10

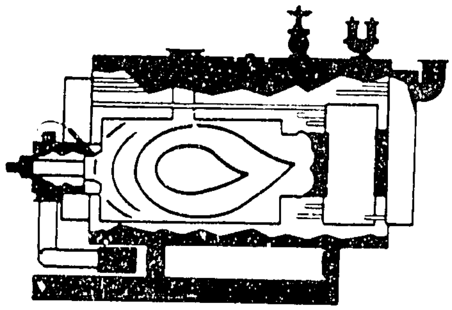
Vekos Boilers

Coal



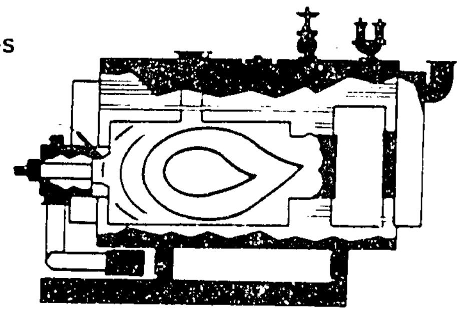
The coal version is unique. The pneumatic feed system delivers coal through a small bore pipe from bunker or hopper (remote) to boiler. The Vekos Multi fuel is well proven, efficient and clean, giving coal firing a modern concept.
This boiler may in addition be arranged for burning the other fuel options, i.e. oil or gas associated with coal.

Oil



The boiler may be provided for burning any grade of fuel oil. The furnace is of large dimensions and easily able to ensure early completion of combustion.
A choice of high efficiency burners is available.
This boiler may in addition be arranged for burning the other fuel options.

Gas



The boiler may be provided for burning any commercial grade of gas. Its large furnace ensures rapid completion of combustion, reduced noise levels and offers the maximum of heating surface to the gas flame.
This boiler may in addition be arranged for burning the other fuel options.

The **trickle feed stoker** is simply a hopper from which coal gravitates onto a rotating feeding table. From there, coal is injected into a feed hole leading to the kiln. These burners are small and are used in banks over the firing zone of the kiln. By connecting a number of the burners via electrically-operated chains, the fuel feed can be automatically controlled.

Hoppers are either filled by hand or by mechanical means, depending on the type of kiln being fired. On continuous kilns, the burners must be moved, as the fire moves around the kiln and as they are normally hand-filled.

A typical **pulverized fuel burner** is shown in Exhibit 11.11. Coal is first milled to a fine powder and conveyed by primary air into the combustion chamber, where it burns entirely in suspension. Secondary combustion air is supplied at the burner to create turbulence after ignition is established, thereby promoting more intense and efficient combustion.

Pulverized fuel burners are more reliable than the other mechanical stokers, but -- because of the requirements for milling -- can have higher operating costs than comparably sized stokers.

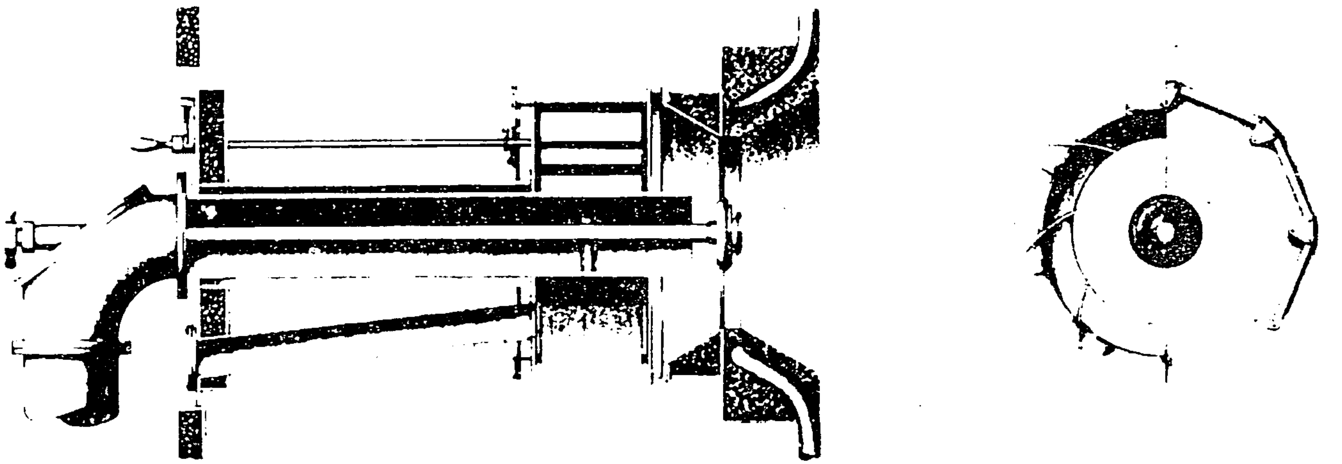
Burners using pulverized fuel can be fired in a number of ways (see Exhibit 11.12):

- Vertical firing
- Horizontal firing
- Tangential firing.

Vertically firing burners fire downward, creating a long flame path. The combustion products eventually reverse their direction and exit the combustion chamber at high level. **Horizontally firing burners** fire through the side walls of the combustion chamber, producing short turbulent flames.

Tangentially firing burners are located at the corners of the combustion chamber and are positioned so that flames form tangents to an imaginary circle at the center of the combustion chamber. The center of the chamber is thereby maintained in a high

Exhibit 11.11



Horizontal short flame p.f. burner (courtesy Babcock & Wilcox Ltd)

Exhibit 11.12

METHODS OF FIRING PULVERIZED FUEL BURNERS

- Vertical Firing
  - fire down
  - long flame
  - combustion produces reverse flow
- Horizontal Firing
  - fire horizontally
  - short flame
- Tangential Firing
  - corner location
  - flame paths form tangents

state of turbulence. Tilting mechanisms are often incorporated so that the combustion zone can be moved about the combustion chamber.

Pulverized fuel burners are used predominantly on large watertube boilers in power stations and on cement kilns.

Fluidized-bed combustors are commercially available to burn solid fuels. In a fluidized bed, the firebed is made to behave as a fluid by passing air through it. Solid fuel particles that make up the firebed are mixed turbulently, leading to very intense combustion. Boiler tubes or material to be heated can be submerged in the fire bed, thereby providing excellent heat transfer rates.

Typically, air is supplied at pressures up to about 0.03 bar (0.36 lb/in^2), and the bed temperature is maintained at about 900°C (1,650°F). The reasons for the upper temperature limit are:

- Materials such as sodium do not form deposits at this temperature.
- The bed will not sinter.
- Sulfur-reactive compounds can be used in the bed to prevent formation of sulfur oxides.
- The fuel composition in the bed can be varied.

Because of the advantages of high heat transfer rates, fluidized bed combustors and their associated boilers are smaller in size than equivalently rated conventionally fired units.

Gas Burners

Gas burners fall into three basic types:

- Neat gas
- Low-pressure aerated or natural draft
- Forced draft.

Neat gas burners consist essentially of a jet or jets through which gas is ejected to burn with a luminous flame. The simplest type of this burner is the drilled bar, which consists of a bar with holes drilled along its length. Required heat release rates govern the number and size of the holes.

Low-pressure aerated burners are used as an improvement on the neat gas burner. A neat gas burner is subject to flame retention problems, and improvements can be made by increasing aeration provided by the burner. In its basic form, the low-pressure aeration burner consists of an injector mounted on a drilled bar. Air is entrained by the injector assembly and mixes with the gas supply. The air/gas mixture passes along the burner bar to the holes through which it is combusted.

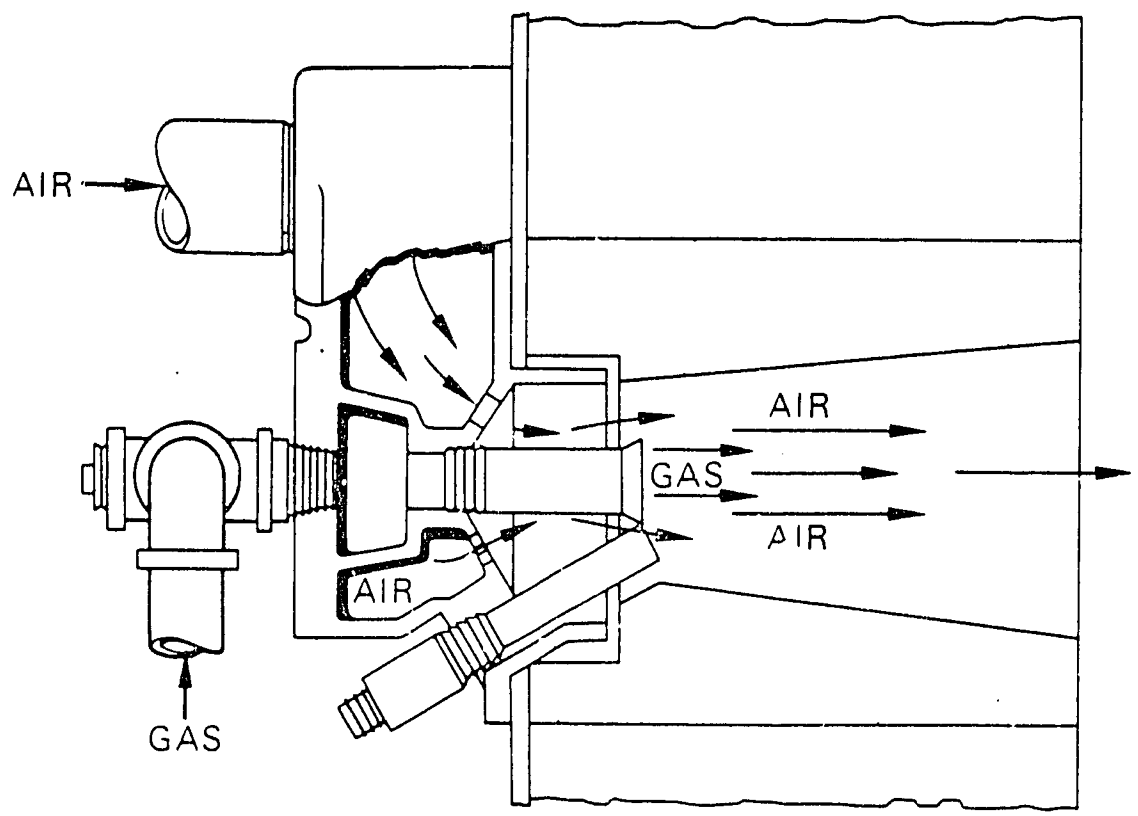
The above system does not adequately meet the requirements for intense combustion. Combustion intensity is controlled by the amount of air and gas that can be burned at one point. Increasing aeration increases the intensity of combustion, but with low-pressure aeration systems operating at about atmospheric pressure, the maximum level of primary aeration is limited to about 60 percent of the ideal air/fuel ratio. By using forced draft burners, the level of primary aeration is not limited, and improved fuel/air mixture ratios are achievable with improved combustion efficiency.

Forced draft gas burner systems are classified as either high-pressure gas or air blast. High-pressure burners use gas at pressure to entrain extra quantities of air. Air blast burners can be categorized as either premix or nozzle mix burners. These terms relate to where the mixing of the gas and the combustion air occurs.

In premix burners, gas is entrained by pressurized air, rather than air being entrained by gas. Gas is normally at about atmospheric pressure. Air pressures are typically 70 mbar (1 lb/in^2). Gas/air ratios are controlled by using an injector coupled with at zero pressure gas governor. The governor regulates the gas at zero pressure, and hence gas is released through suction caused by air flow.

Nozzle mix burners do not mix the fuel and air until they both reach the burner head. However, the orifices through which both fluids pass are designed to provide mixing as they leave the burner head. An example of a nozzle mix burner is shown in Exhibit 11.13.

Exhibit 11.13



Cross section of a typical nozzle mix burner (Courtesy Urquhart Engineering Co Ltd).

Combination Burners

Burners are manufactured that are capable of firing different types of fossil fuels. The most common combination burner is the oil/gas burner, which is designed to burn either oil or gas, as appropriate. These burners are usually similar in construction to the burner types described earlier. Typically, a pressure jet is used for oil burning, and gas is supplied through an annular tube or jets surrounding the oil burner.

Combination burners are used most widely where fuel interruptions occur in the supply of the main fuel source. Because of their similarity to oil and gas burners, they will not be discussed in detail.

BOILER TYPES

There are two predominant types of boilers used in industry: the firetube or shell boiler, and the watertube boiler. Other sorts of boilers exist, but they will not be discussed in this session. The basic function of the two types of boilers was outlined in Session 4 of this seminar, and hence will not be repeated in this session.

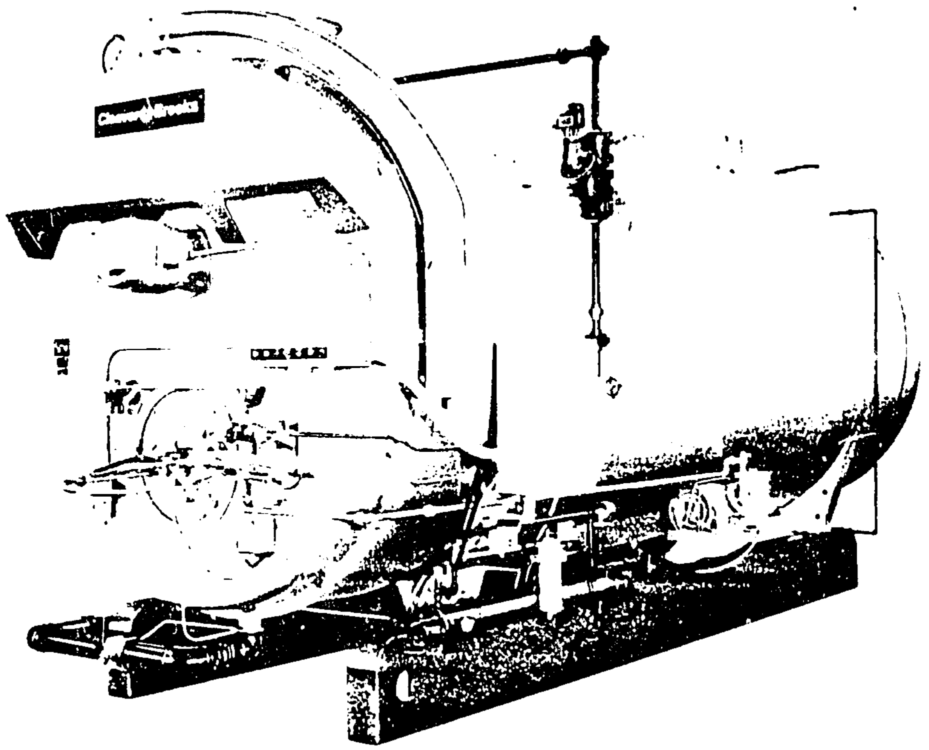
Firetube Boilers

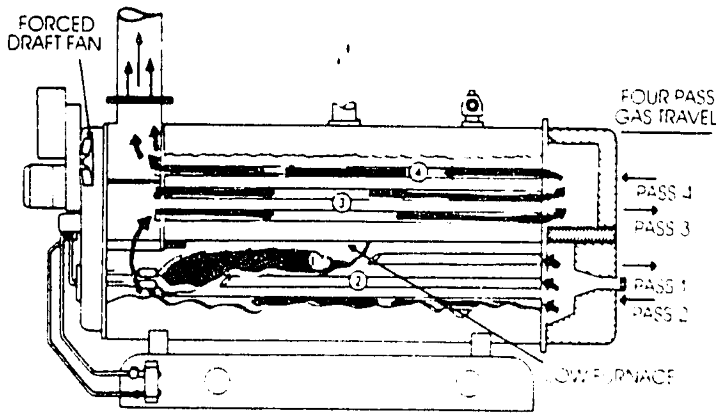
Firetube or shell boilers are boilers in which heat transfer surfaces are all contained within the steam-water drum or shell. They are called firetube boilers because the products from fuel combustion pass through tubes forming the heat transfer surfaces. The firetube boiler is used in industry predominantly to produce steam for process requirements. Firetube boilers can raise steam or heat water from all fossil fuels or alternately by burning waste products. An example is shown in Exhibit 11.14.

Combustion takes place in a furnace tube sized according to the fuel type. The burner fires horizontally along the furnace tube. Hot gases formed by combustion enter a steel combustion chamber lined with firebrick. If the chamber is surrounded by water, the boiler is called a wetback boiler. If the chamber is not surrounded by water, the boiler is called a dryback.

Exhibit 11.14

Firetube Boiler





On exiting the combustion chamber, combustion products pass horizontally through a series of smoke tubes contained in the steam-water shell. Combustion gases pass through the smoke tubes, reversing their flow at the end of the boiler. In some boilers, the gases pass through the shell three times before exiting via the stack, and hence the boilers are known as three-pass boilers. More recent designs have four passes, resulting in a corresponding increase in boiler efficiency. Firetube boilers are therefore called both wetback or dryback and three- or four-pass.

The firetube boiler is used to generate steam up to 24 bar (350 lb/in^2). At greater pressures, the shell size becomes too large, and pressures on the furnace tube become too great. The maximum shell diameter used is about 4.27 meters (14 feet). Maximum steam generation rates are equivalent to 28,800 kg/hr (63,500 lb/hr).

Firetube boiler efficiency is dependent on the basic design of the boiler, fuel used, operating conditions, and whether any auxiliary heating surfaces such as economizers and/or air preheaters are used. Efficiencies typically are around 80 percent of the gross calorific value of the fuel.

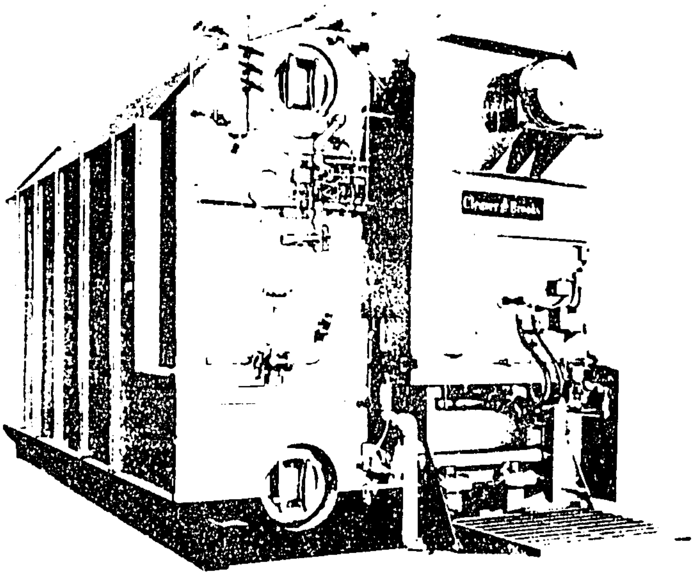
Generally, boilers fired on oil are more efficient because of better heat transfer characteristics associated with oil flames, provided that good, clean combustion is maintained. Gas-fired boilers are slightly less efficient but tend to burn cleaner, so over an extended time period they may not foul heat transfer surfaces as much as oil-burning systems. Thus, their efficiency may be better than that of an oil-fired plant.

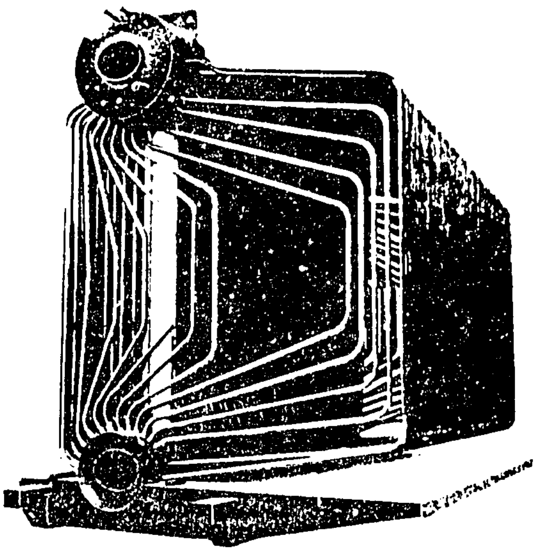
Watertube Boilers

A watertube boiler is a boiler in which water circulates through tubes connected directly to a steam drum, a steam and water drum, or headers. An example is shown in Exhibit 11.15. Watertube boilers raise steam by combustion of fossil fuels or, alternately, by burning waste products. Fuel is burned in a combustion chamber that is surrounded by the tubes that contain the water. These tubes in turn are normally enclosed in a brickwork structure, thermally insulated, and encased in an outer metal casing.

Exhibit 11.15

Watertube Boiler





Heat transfer occurs through two ways, radiation and convection. The tubes that are heated by radiation are known as waterwalls and are exposed directly to the flame or fuel bed. Sometimes the waterwalls are located about the combustion chamber walls. Tubes that are primarily heated by convection are usually grouped together in nests and shielded from the burning fuel. Radiant tubes absorb more heat than the convection tubes.

Water circulation is of prime importance in a watertube boiler; without circulation, heat cannot be carried away from the combustion chamber. Local hot spots can lead to rupturing and tube failure can occur. Water circulation is either completed by natural circulation or forced using a pump.

In the natural circulation boiler, steam bubble formation in the water causes a lowering of density in comparison with water alone. This density difference provides the driving force for natural circulation to occur.

Resistance to circulation is caused by friction losses in the boiler tubes, headers, and return pipes, which tends to reduce the amount of circulation. However, as more heat is applied and received by a tube, the greater the steam formation and, hence, the greater the water circulation rate. The natural circulation boiler is inherently self-adjusting to the heat input.

Pump-assisted boilers permit greater flexibility in the design of a boiler, allowing more choice for location and size of the tubes. However, they are more mechanically complex, resulting in greater maintenance requirements. In addition, the pump requires energy to run. Unlike the natural circulation boiler, the circulation balance does not adjust itself to the heat input pattern. Watertube boilers can produce as much as 1.8 million kg/hr (4 million lb/hr) of steam at pressures in excess of the critical steam pressure of 221 bar (3,205 lb/in^2). Because of this, watertube boilers are used in power stations as well as in industrial facilities.

Watertube boiler efficiency is comparable to that of the firetube boiler. However, watertube boilers are much more likely to use economizers, superheaters, and air preheaters to capture waste heat from the flue gases.

HOUSEKEEPING MEASURES

The operation of burners and boilers is affected by a number of factors. This section of the session will indicate some of the more common items that have adverse effects on combustion equipment and boiler operations. Major mechanical failure will always have a negative impact on efficient operation but will not be considered in the following paragraphs.

To ensure that any maintenance and housekeeping measures are successfully followed, it is necessary to keep records of work completed in addition to monitoring operational conditions at regular intervals and maintaining a log. By monitoring, any changes can be detected that potentially influence the performance of either a burner or boiler. A listing of relevant information for recording in a boiler log is shown in Exhibit 11.16.

Maintenance of a burner or boiler system at optimum efficiency is usually one of the most cost-effective steps that can be taken. Often these systems are the single largest energy users at industrial facilities.

Because boilers normally use burners as their source of heat, maintenance measures will be presented for a boiler system only, but will incorporate housekeeping measures that can be applied to oil-, solid fuel-, and gas-fired burners to ensure optimum combustion performance at all times.

For good boiler operation, the following systems must function correctly:

- Fuel handling system
- Burner mechanical air supply and electrical systems
- Boiler feedwater systems.

Housekeeping measures can be applied to all systems and are outlined in the following paragraphs.

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Exhibit 11.16

Boiler Information to Be Logged

General data to establish unit output
- Steam flow, pressure
- Superheated steam temperature (if applicable)
- Feedwater temperature

Firing system data
- Fuel type (in multifuel boilers)
- Fuel flow rate
- Oil or gas supply pressure
- Pressure at burners
- Fuel temperature
- Burner damper settings
- Windbox-to-furnace air pressure differential
- Other special system data unique to particular installation

Air flow indication
- Air preheater inlet gas O_2
- Stack gas O_2
- Optional: air flow pen, forced-draft fan damper position, forced-draft fan amperes

Flue-gas and air temperature
- Boiler outlet gas
- Economizer or air heater outlet gas
- Air temperature to air heater

Unburned combustion indication
- CO measurement
- Stack appearance
- Flame appearance

Air and flue-gas pressures
- Forced-draft fan discharge
- Furnace
- Boiler outlet
- Economizer differential
- Air heater and gas-side differential

Unusual conditions
- Steam leaks
- Abnormal vibration or noise
- Equipment malfunctions
- Excessive makeup water

Blowdown operation

Soot-blower operation

Fuel Handling System

The following checkpoints should be considered:

Oil Storage and Handling

- Drain water from oil tanks monthly.
- Check operation and clean filters and pumps monthly.
- Test fire valves for correct operation weekly.
- Monitor oil temperature before and after line heaters daily for correct heater function.
- For insulated tanks, check condition of insulation.

Coal Storage

- Maintain coal storage supplies on concrete to reduce breakdown.
- Turn stored coal regularly to prevent risk of spontaneous combustion and to prevent bridging.
- Keep areas around coal storage bunkers clear of foreign objects that could cause damage to coal handling equipment.
- Mix fresh coal with old to ensure that old stock is used regularly.
- Keep coal as moisture-free as possible.
- Inspect coal handling systems weekly for correct operation.

Gas

- Check supply pressures daily.
- Check governor valve operation by monitoring pressure daily.
- Test shut-off valves for correct operation weekly.

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Burner Mechanical Air Supply and Electrical Systems

There are several measures that must be considered for correct maintenance of burner systems. They include correct starting and stopping procedures, routine maintenance of safety controls, and monitoring of combustion conditions. The measures are outlined in the following paragraphs.

Start-Up Checklist

Whenever the burner is started after routine shutdown, the following items should be checked. This list is not meant to replace manufacturers' start-up procedures, nor is it presented in a sequence that must be followed. It is presented for information only.

- Place all electrical switches and fuel shut-off values in "OFF" position.
- Check combustion chamber for soundness and cleanliness. Make certain that there are no signs of seam or weld separation.
- Inspect the refractory around the burners, ascertaining that there are no cracks or other deterioration that may cause air leakage or flame distortion.
- Check fan belts for proper tautness, alignment, and soundness. Make certain that belts and sheaves are properly aligned and that all set screw are secure.
- Make sure that motors and blowers are lubricated. Manually turn blowers, fans, and motors to check for lubrication and ease of movement. Also, inspect any auxiliary equipment such as mechanical timers for lubrication.
- Inspect flue passes and economizer tubes for possible blockage, dust, dirt, or scale.
- Make certain that dampers are in proper position.
- Check flue pipe for corrosion and general repair.
- Check for availability of combustion air supply to boiler room.
- Observe control settings. Switch should be in the automatic position for normal operation. If unit is equipped with mechanical purge-timing device, check its setting.

- Press reset buttons at main burner relay, motor overload resets, and overload relay in line starter. Reset electronic relay (safety pilot).
- Make certain that fuel supply lines are all open.
- Ensure that the flame rod or thermocouple in the pilot assembly is properly positioned and intact.
- Generally observe the installation in its entirety, making a concentrated effort to note any irregularity or discrepancy before fire-up.
- Check fuel piping and connections for leaks.
- Check electrical wiring and connections for intactness and security.
- Make certain that all accessible relay contacts are clean.
- Lubricate components as necessary.
- Ensure that inlet and outlet air dampers are not jammed, damaged, or otherwise impaired.
- Check blowers, burner head, inlet screen, or filter for dirt blockage.
- Conduct concentrated inspection of all controls, valves, linkages, weatherproofing, and the unit in its entirety to note any irregularity.

The following is a list of routine maintenance procedures by time frame for burner systems. It is <u>not</u> designed to replace recommended manufacturers' maintenance instructions, but serves as a guide for efficient operation.

Weekly:

- Inspect fan belts, shaft set screws, and sheaves for tightness and alignment.
- Check burner pressure and fuel temperature.
- Check burner head for leaking oil, which can cause excessive carbon build-up on burner tile.
- Check flame characteristics.
- Observe stack temperature.
- Compute boiler/combustion efficiency.

Monthly:

- Check lubrication of fan shaft bearings.
- Check all valves, piping, and connections for leaks.
- Check damper settings.
- Remove pilot assembly and check spark plug, flame rod, electrical leads, and pilot head.
- Check orifices, air passageways, and fan blades for cleanliness.

Every three months:

- Check stack condition, stack connections, support, and draft.
- Relubricate all ball bearings with a good grade of ball-bearing grease.
- Check combustion efficiency, making certain that fuel-air ratio and input at least approximate optimum conditions.

Yearly:

- Remove economizer tube access plates below control box and remove swirler baffles from tubes. Clean economizer tubes with stiff brush and air hose.
- Inspect refractory around burner. If there are any signs of cracking or damage, repair or replace.
- Clean air exhauster, fan wheels, and vanes.
- Turn off main disconnect switch and open control box. Make certain that controls are clean and free from dust and grease. Check and clean relay starter contacts and inspect for any loose contacts or wiring. Use nothing more abrasive than a business card in cleaning contacts.
- Clean fuel supply system and shut-off valves. If possible, check valve for tightness.
- Lubricate fan motor as directed by motor manufacturer.
- Check condition of combustion chamber. Attend to any areas where there is evidence of any incipient failure or undue wear or distortion.

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Boiler Feedwater Systems

The boiler feedwater system needs specific attention. Water properties vary, and water treatment may be required for a number of reasons. Factors that affect the operation of boilers include:

- Dissolved solids and salts, including hardness
- pH
- Dissolved gases
- Suspended matter.

Water conditioning is designed to condition boiler water to prevent the following:

- Scale formation
- Corrosion
- Production of wet steam.

Various methods of treatment are used to overcome the factors affecting water use, including external treatments such as:

- Clarification
- Coagulation and flocculation
- Filtration
- Precipitation softening
- Ion exchange
- Degassing and aeration.

Internal treatments are used to prevent foaming and priming, as well as to neutralize condensate. Because of the range of treatments that can be applied, no specific recommendations are made except the following:

- Check the condition of water quality daily to see if it conforms with recommended specifications for total dissolved solids, alkalinity, chlorides, etc.

- Operate water treatment plant in accordance with manufacturer's recommendations.

Boiler Plant

The actual boiler requires specific attention to ensure optimum efficiency. A boiler functions by transferring heat to a fluid; hence, there are two prime areas that must be maintained -- the heat transfer surfaces on the gas and water sides. By ensuring that all firing equipment is serviced and combustion testing with subsequent adjustment of fuel-air ratios is conducted on a regular basis, gas side heat transfer should be optimized. Correct water treatment, coupled with the proper amount of blowdown for removal of sludge from the boiler, should maintain "clean" heat transfer surfaces on the water side.

Routing cleaning of the boiler should be done on an annual basis, when the boiler should be taken off-line and stripped down for annual inspection. At this time, all controls, valves, fittings, etc. should be thoroughly inspected and repairs made as necessary.

Detailed annual maintenance procedures are not presented but are available from manufacturers, and should conform to any safety or insurance requirements as necessary for boiler operation.

Energy Conservation Measures

Identifying which measures or investments can be made to improve a boiler performance is the result of the establishment of the energy balance (see Session 2 for a detailed boiler energy balance). When losses have been identified, then specific action or projects can be evaluated. Major types of conservation measures are presented that can be applied to reduce energy consumption by burners and boilers without adversely affecting their operation. The section is presented in two parts. A brief review is given of some no-cost/low-cost operating and procedure changes, and then equipment modifications, replacements, and retrofits are outlined.

Operating and Procedure Changes

The following checklist indicates conservation opportunities for combustion equipment and boilers that can be implemented with little or no capital expenditure.

- Regular tuning of fuel/air ratios will maintain high combustion efficiency. This should be performed quarterly by qualified combustion engineers; in the United States, it typically costs $400. Savings from tuning range from 1 percent to 3 percent of the fuel input.
- Derate oversized burners to prevent excessive cycling and high radiation losses during off-cycle. Derating an oil burner can be done by selecting a smaller-sized burner tip.
- Fuel/air ratios and damper controls should be adjusted so that proper draft conditions are used at all rates of firing. Incorrect quantities of draft can lead to too much or too little combustion air being used, with a corresponding reduction in combustion efficiency. The effect of excess air (oxygen) on boiler efficiency is shown in Exhibit 11.17.
- Reduce boiler operating pressure to lowest required for satisfactory distribution and process requirements. Care must be taken when reducing pressure, however, as overreduction of pressure can cause water carryover from the boiler into the steam distribution system. Boiler pressure can be reduced whenever the boiler is at standby, or should be shut down completely if there is no standby requirement. Savings from reducing pressure are shown in Exhibit 11.18. This measure can be implemented by altering boiler pressure stats and costs nothing to implement.
- Review boiler size with respect to steam load. Operate smaller plant wherever possible to reduce radiation losses from the boiler. The effect of radiation losses and low load factor on boiler efficiency can be seen in Exhibit 11.19. The cost of implementing this measure depends on available plants and thus is not presented. It may even be economic to install a smaller boiler.
- Blowdown should be reduced to the minimum required to prevent excessive scale formation. The percentage fuel savings from reducing blowdown are shown in Exhibit 11.20. It is necessary to know the boiler operation pressure and the current blowdown rate to estimate the savings.

Exhibit 11.17

Variation in Boiler Efficiency Losses with Excess O_2

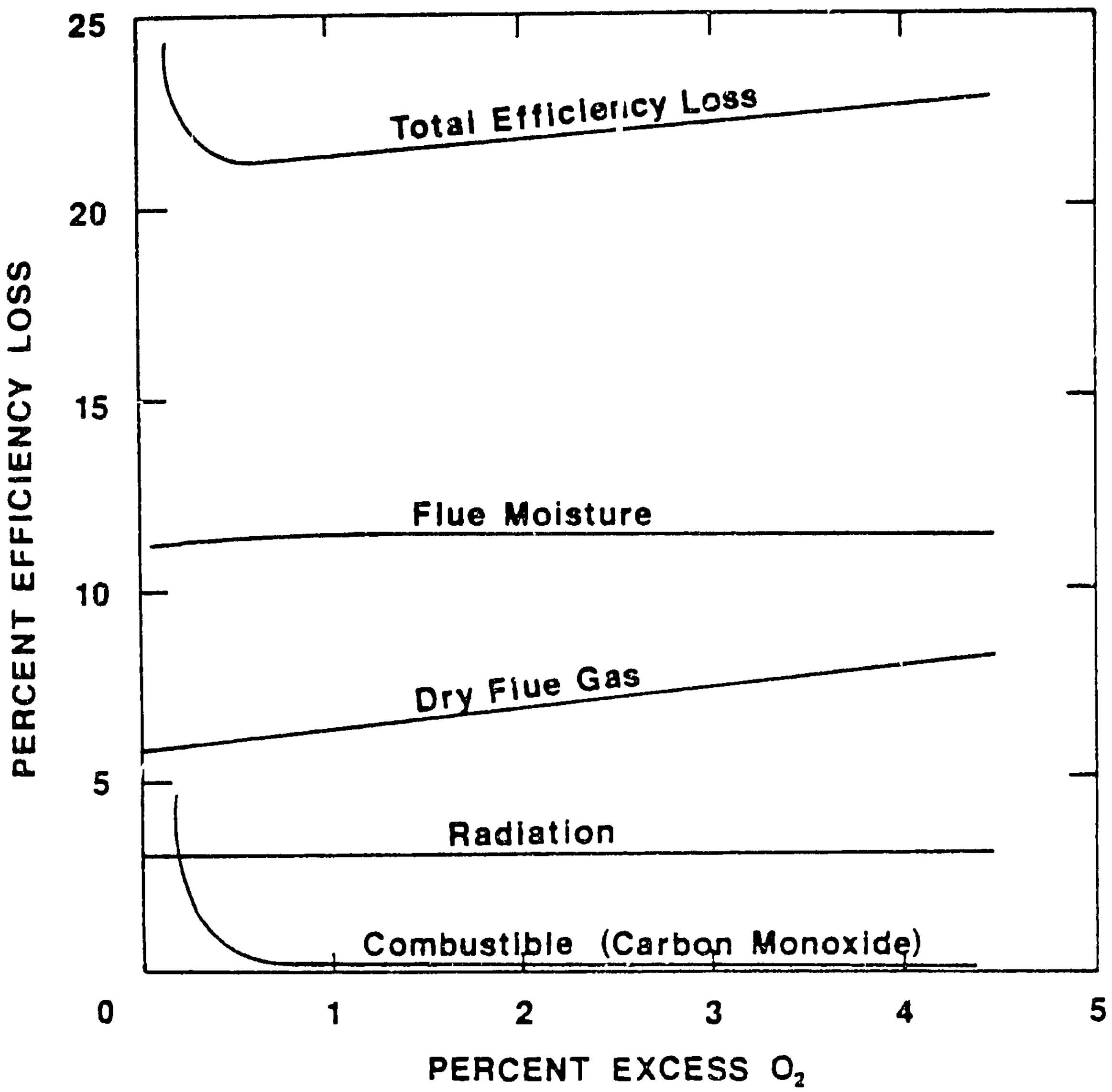

Exhibit 11.18

Efficiency Improvement from Reducing Boiler Operating Pressure

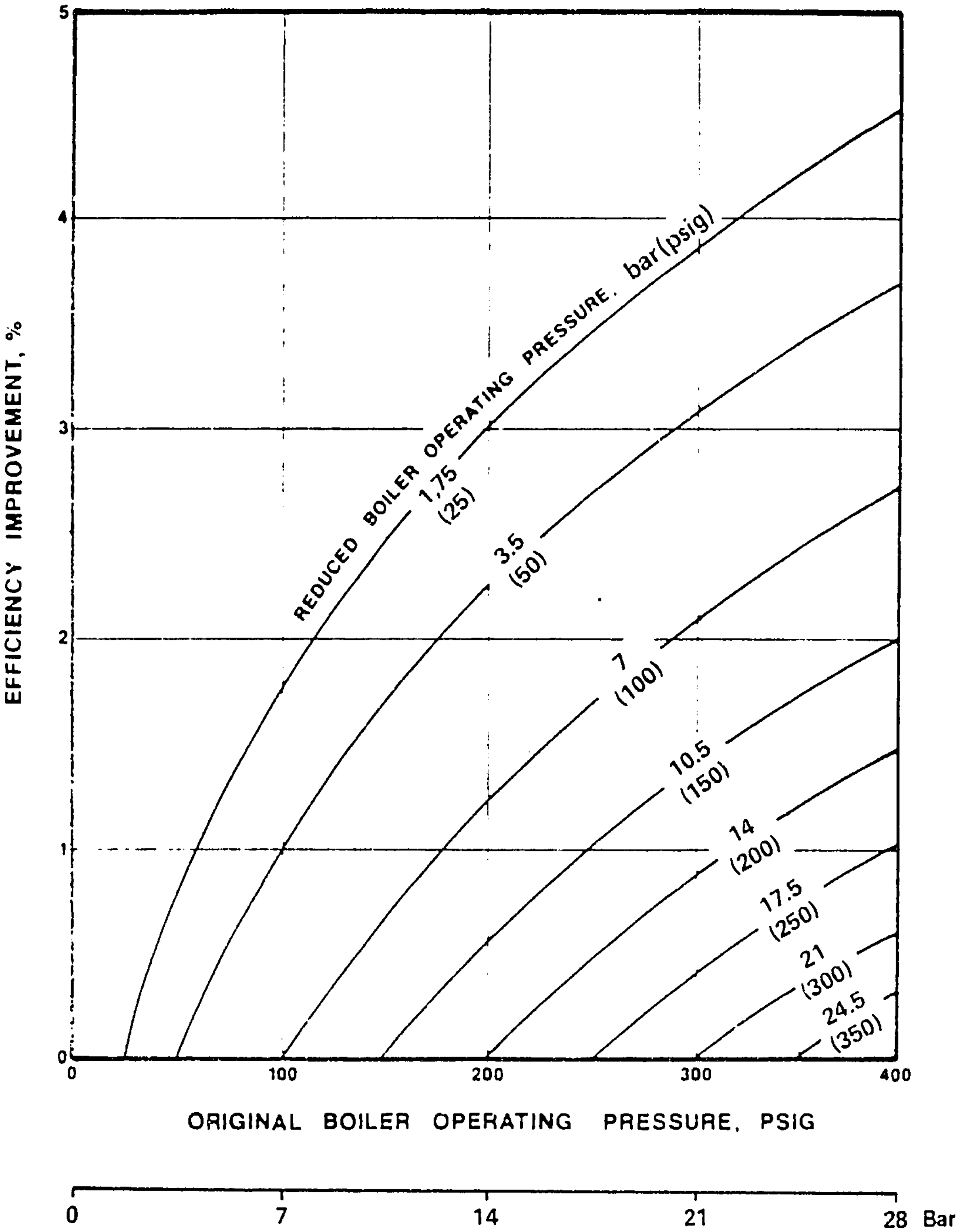

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Exhibit 11.19

Variation in Boiler Efficiency Losses with Firing Rate

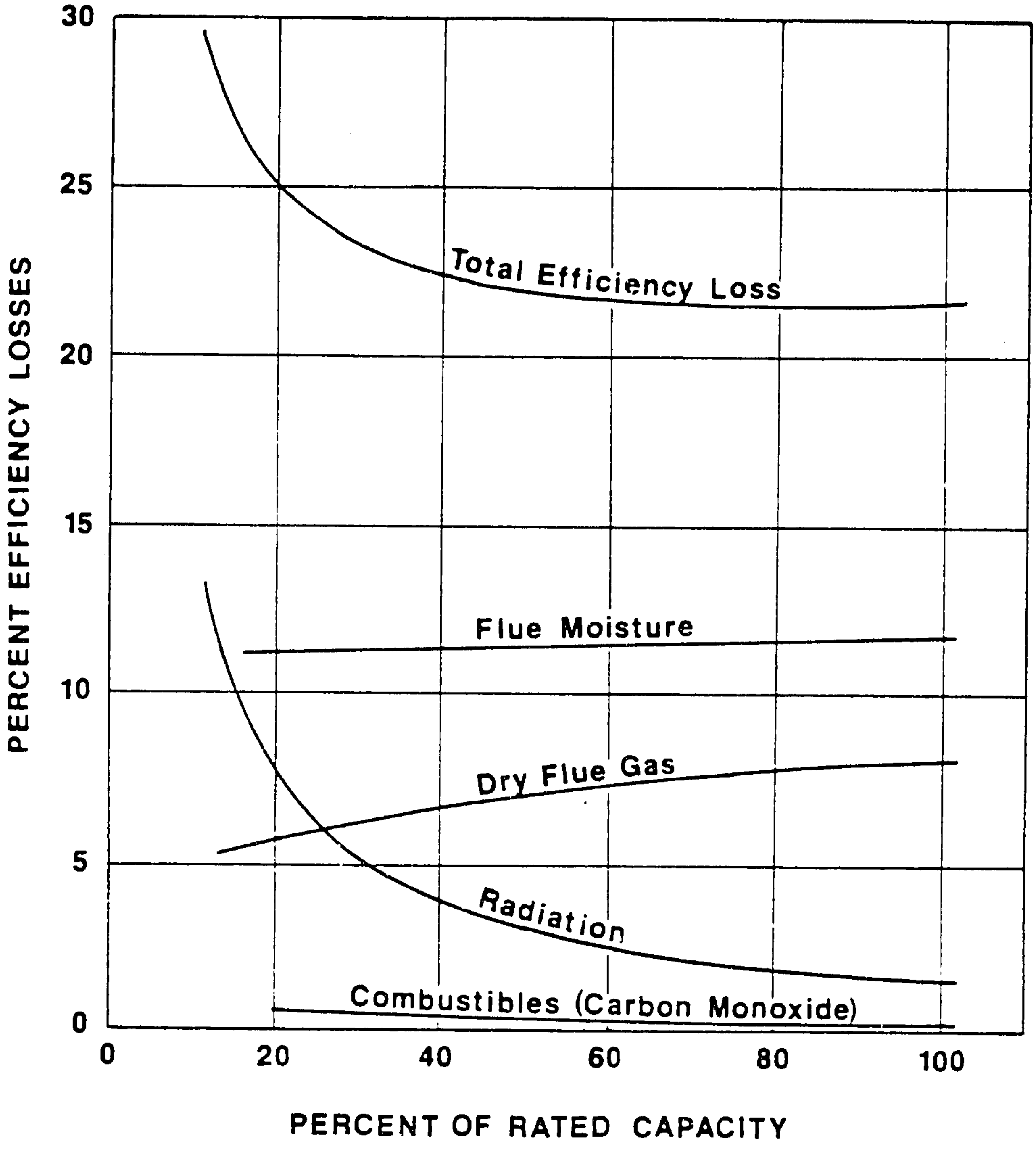
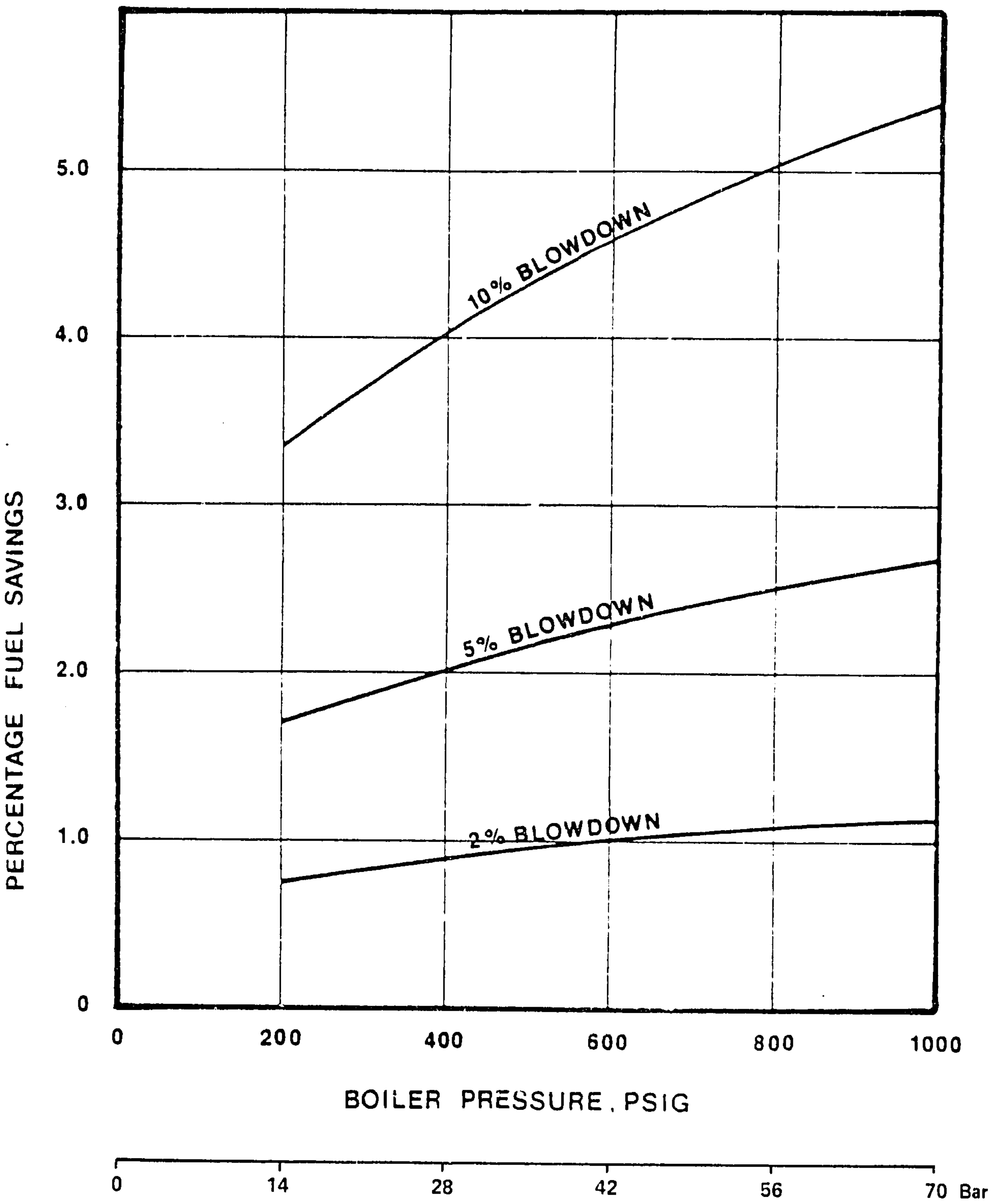


Exhibit 11.20

Fuel Savings from Blowdown Heat Recovery



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Reduction in blowdown costs nothing to implement and can save water chemical treatment costs.

- Missing or damaged insulation should be replaced on the boiler plant and ancillaries, as well as on steam and condensate distribution systems. Exhibit 11.21 shows heat loss from a bare surface based on the difference in temperature between the hot surface and the surrounding air temperature. Costs for insulating boiler surfaces depend on the thickness of insulation plus the cost of labor used. One square meter (10.7 square feet) of 25 mm (1 inch) thickness of insulation typically costs $100 (installed) in the United States. The major portion of this cost is the labor element, which normally represents more than 70 percent of the cost.

Modifications, Replacements, and Retrofits

The following checklist indicates conservation opportunities that can be employed with combustion equipment and boilers to reduce energy costs. These measures require equipment modifications, retrofit, or replacement, and can involve major capital expenditures. Before contemplating any of these measures, it is recommended that a full evaluation be completed, including testing and energy-saving and cost-benefit analysis.

- Install flue gas analysis equipment to monitor flue gas conditions. Flue gas analysis equipment should measure, at a minimum, temperature and the percentage of oxygen or carbon dioxide. If these conditions are monitored on a regular basis, changes such as increasing flue gas temperature can readily be identified. Increasing flue gas temperature is an indication that heat transfer surfaces are becoming dirty, with a corresponding decline in efficiency. The effect of increasing stack temperature on efficiency is illustrated in Exhibit 11.22. Costs for flue gas analysis equipment depend on the sophistication of the equipment and the parameters that are to be monitored. An oxygen analyzer and temperature indicator can be purchased and installed for approximately $3,500 in the United States.
- Fit an oxygen trim system to the burner's fuel/air ratio control to reduce excess air levels. Typical U.S. installed cost for firetube boiler rated

Exhibit 11.21

Heat Energy Loss from a Bare Surface

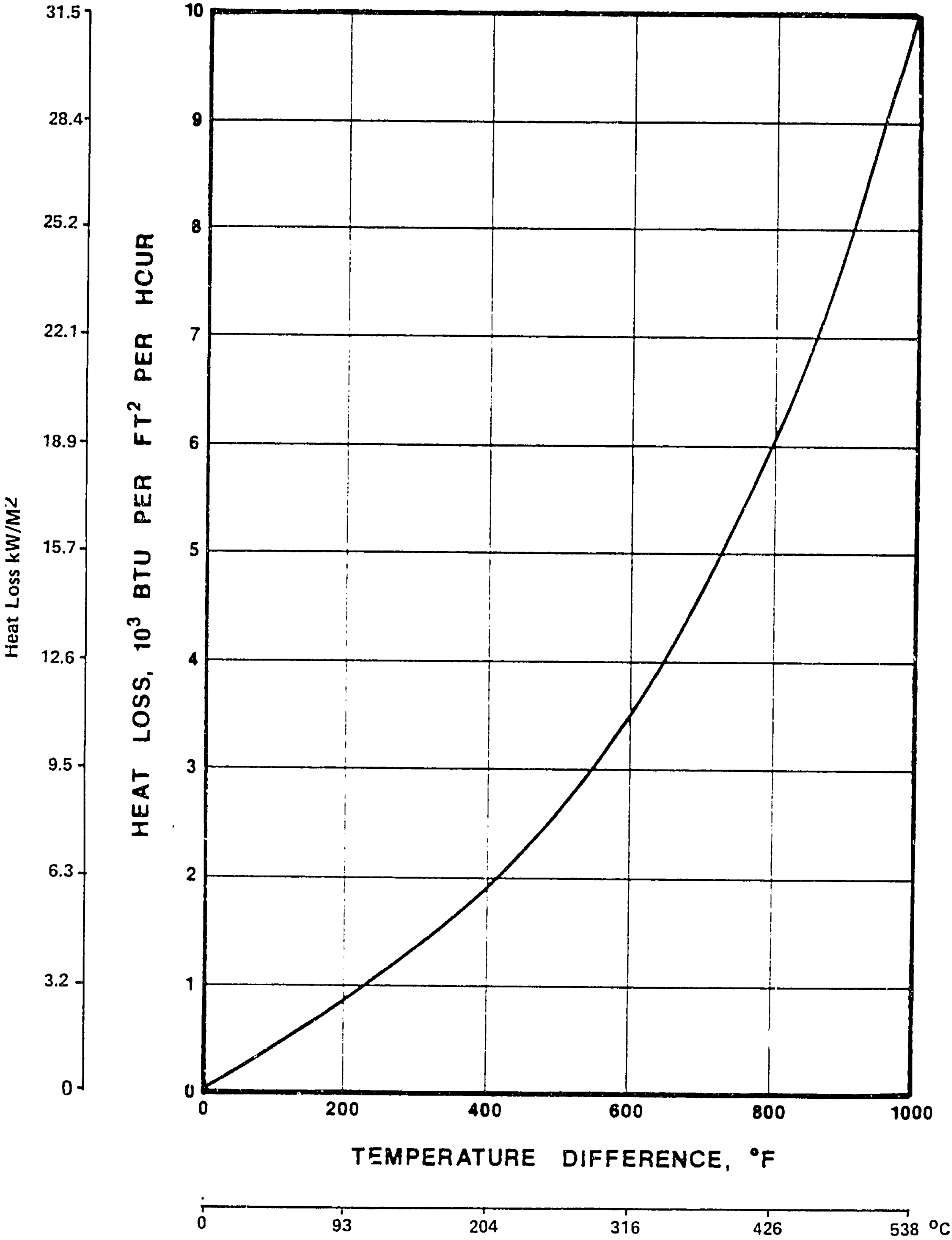

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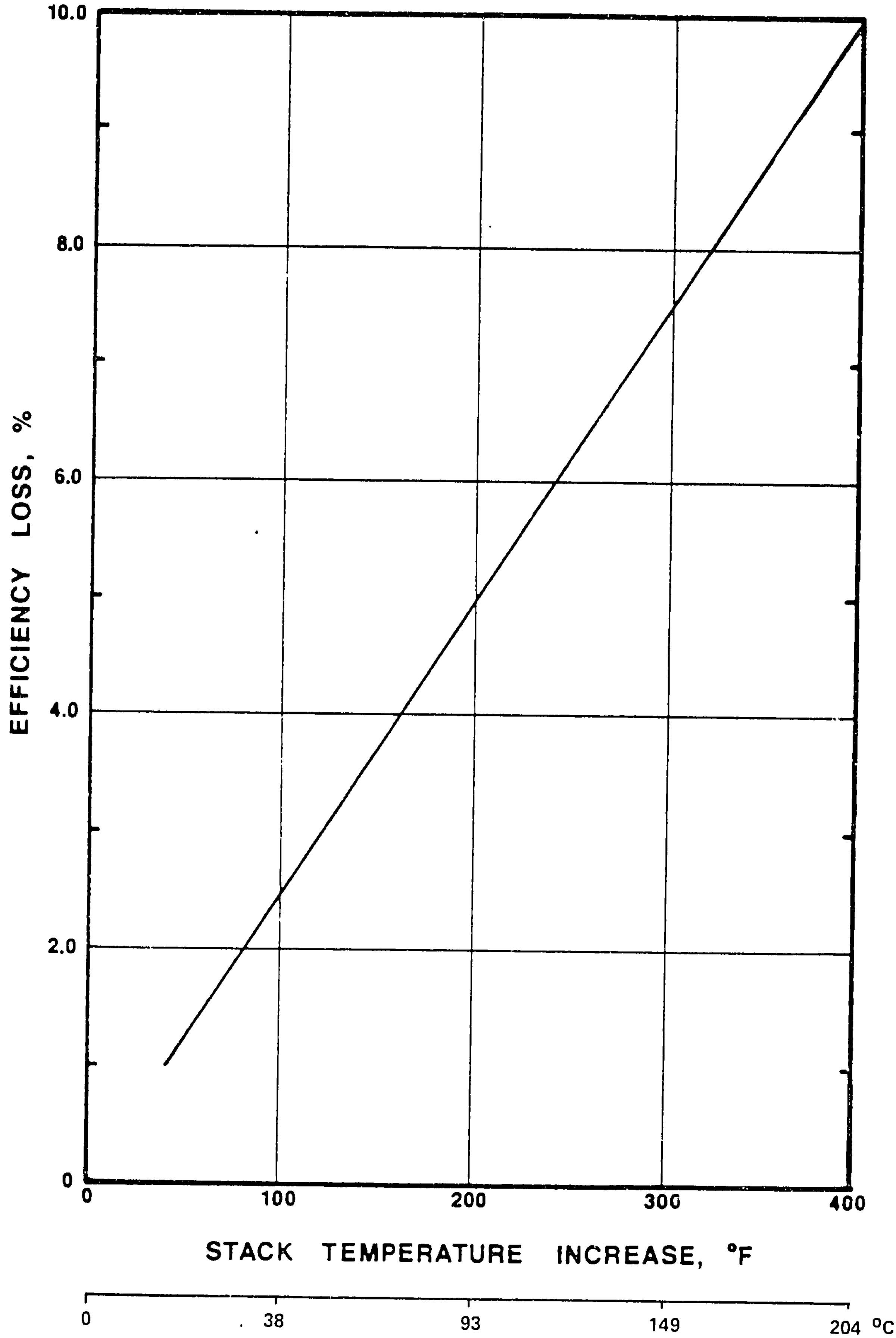
Exhibit 11.22

Efficiency Loss from Stack Temperature Increase



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at 2.9 MW (10,000 lb/hr) is $10,000. Efficiency improvement is normally 1 to 3 percent. Simple payback is less than 2 years. The effect of excess oxygen on efficiency is shown in Exhibit 11.23.

- Recover heat from blowdown to preheat feedwater using a blowdown heat recovery system. Typical U.S. installed cost for equipment is approximately $15,000 to $20,000. Savings usually pay back in less than 3 years.
- Replace inefficient burners. Installed costs depend on replacement burner. They can range from $5,000 to $30,000 for boiler plant. Efficiency improvements can be high, more than 10 percent. Paybacks range from 1 to 3 years.
- Replace inefficient boilers. Capital costs can be high (more than $100,000 for a 10 MW oil-fired boiler), but savings can make the measure financially attractive. When completing evaluation, all aspects of boiler plant operation should be considered: loading, combustion and heat transfer efficiency, fuel type, planned expansions, process changes. Boiler plants typically have a life expectancy of more than 25 years; therefore, all factors must be considered before changing boilers. It is impossible to predict costs and savings.
- Convert on-off burners to fully modulating boilers to reduce cycling. It may be possible to do so only by replacing the burner. Costs and savings would thus be dependent on this factor.
- Convert manual control burners to automatic combustion control. Implementation of this measure may require a replacement burner, and again, costs and savings would depend on this factor.
- Install turbulators in firetubes of two- and three-pass boilers. Turbulators increase the heat transfer from combustion gases to the water side. Installed costs range from $3,000 to $5,000 for a 2.9-MW (10,000 lb/hr) boiler. Savings of 1 to 3 percent are common, with typical payback periods of less than 2 years.
- Preheat combustion air using hot flue gases; applicable mainly on very large boilers. Efficiency improvements are shown in Exhibit 11.24. Costs range from $10,000 to $100,000, depending on boiler size. Typical efficiency improvements range from 2 to 5 percent.
- Fit economizers. Economizers heat boiler feedwater indirectly, using flue gases. Costs range from $10,000 to $100,000, depending on boiler

Exhibit 11.23

Variation in Boiler Efficiency Losses with Excess O_2

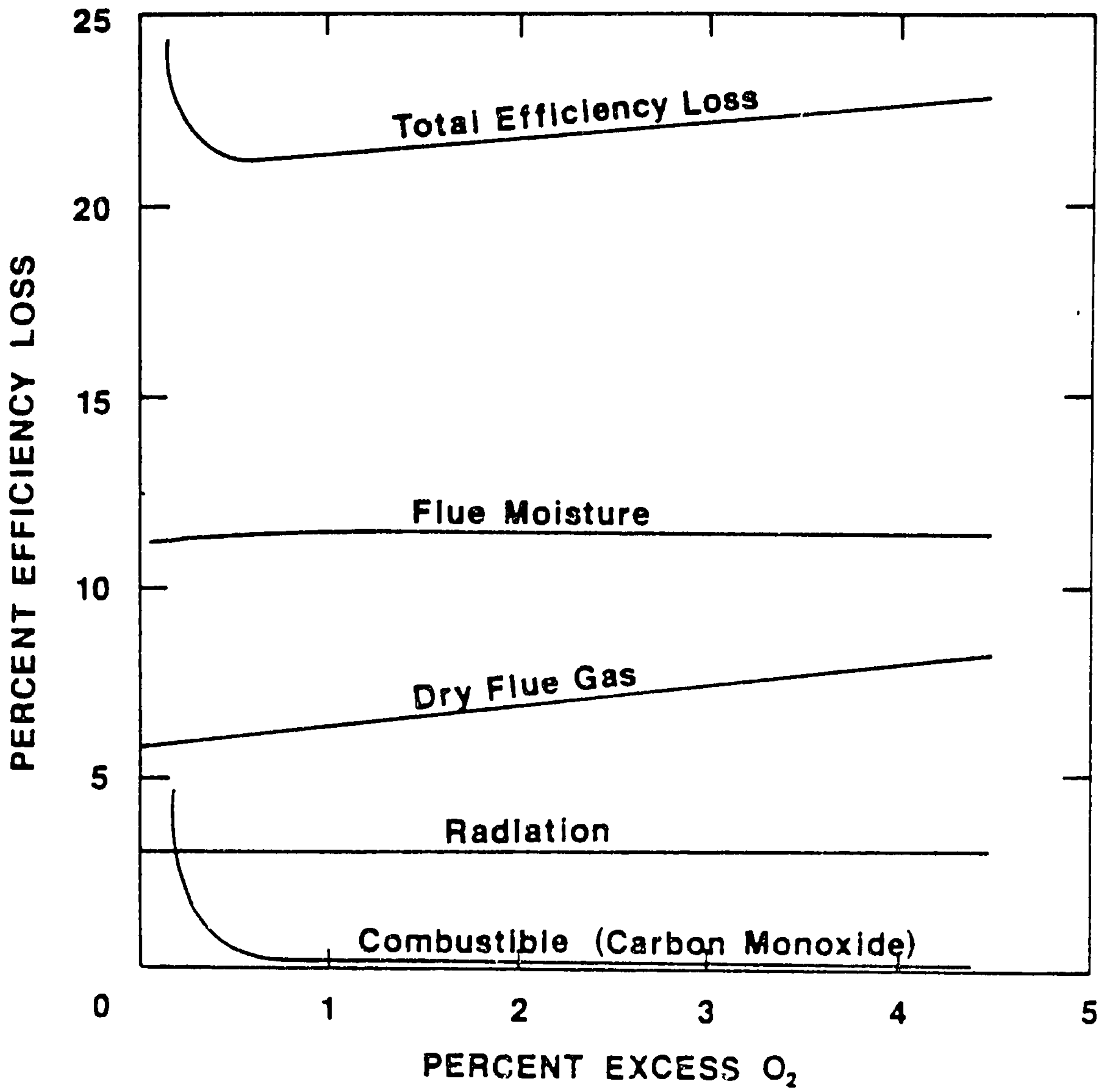
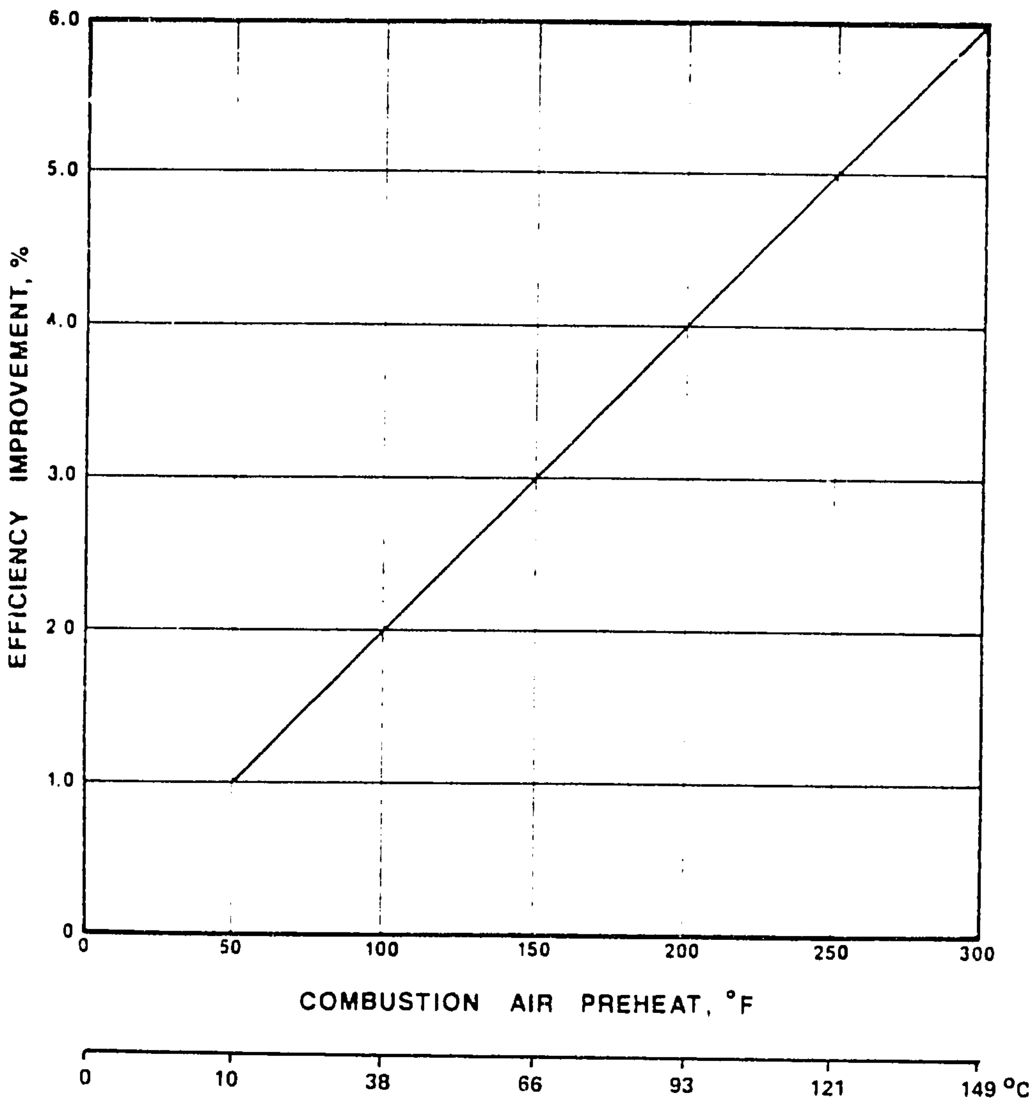


Exhibit 11.24

Efficiency Improvement from Combustion Air Preheating



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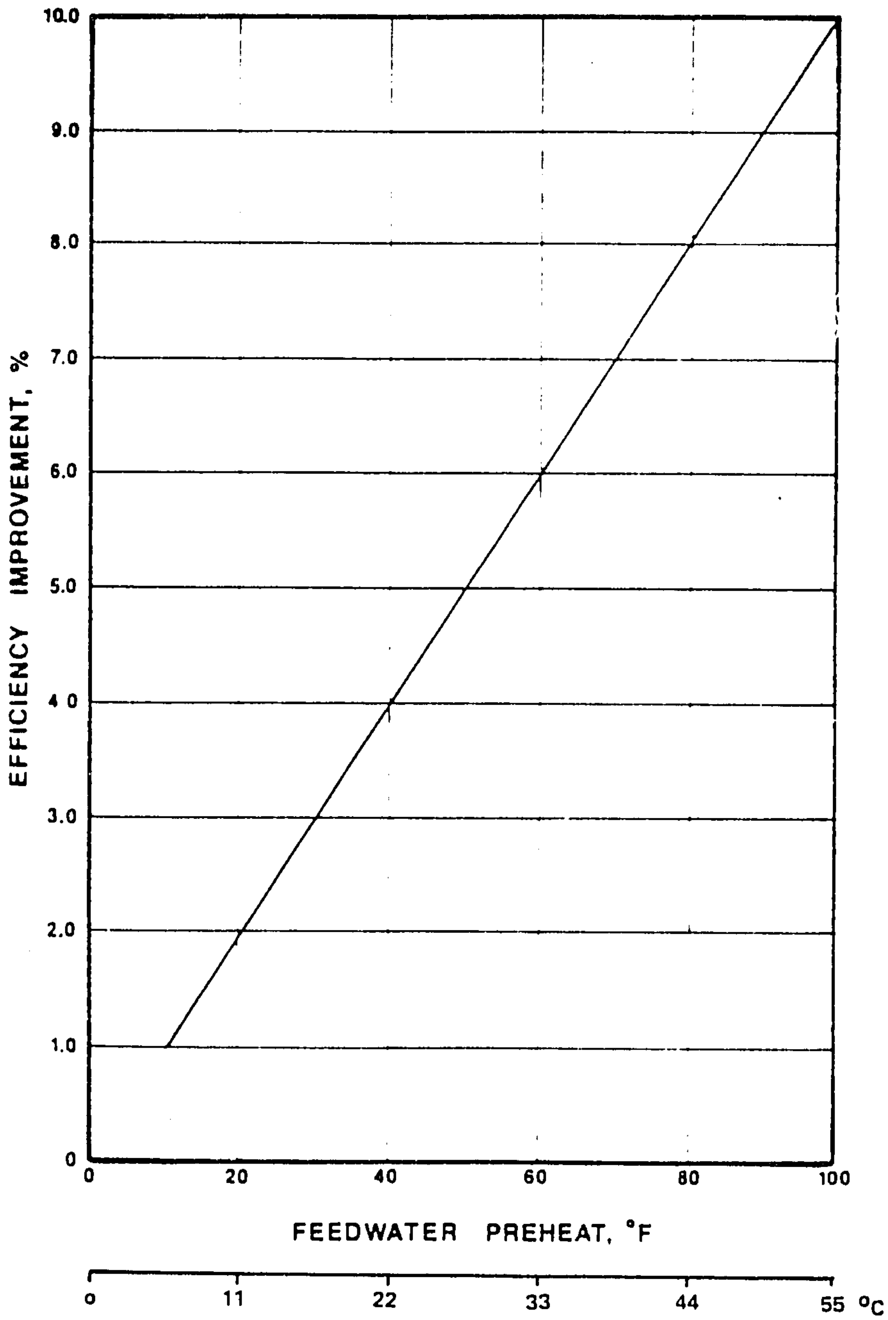
size. Typical efficiency improvements are 3 to 5 percent, and payback periods of 3 to 5 years are common. See Exhibit 11.25 for savings potential.

- Use heat extractor system. The heat extractor recovers latent and sensible heat from flue gases by direct contact with an alkaline solution. The heated solution is then used to preheat water via a secondary heat exchanger. Capital costs can be very high because of the need to use stainless steel and other noncorrosive materials for all heat exchange and piping connections. Energy savings can be as high as 7 to 10 percent, so major capital expenditure may be worthwhile.
- Return condensate under pressure direct to boiler. For plants with one major source of steam consumption (e.g., a corrugated paper machine), condensate at high temperature can be returned under pressure directly to the boiler, with subsequent energy savings owing to the increased feedwater temperature. Typical condensate pump prices can be $10,000 to $20,000. Savings can be 3 to 5 percent, and payback periods are typically less than 2 years.

Exhibit 11.25

Efficiency Improvement from Feedwater Preheating



HOW TO GET A 5% REBATE ON BOILER OPERATING COSTS
By David Dyer, P.E.

Part II of a four-part series on boiler efficiency improvement

What would a five-percent rebate on your boiler fuel costs add to your company's bottom line? Thats how much fuel savings we have found can be obtained in a typical plant by employing boiler heat recovery techniques. And the average payback on the combination of necessary modifications is usually less than one year. For example, improving boiler efficiency by five percent, a continuous load boiler producing 40,000 pounds of steam per hour at an average boiler fuel cost of $4.00 per million Btu can save, conservatively, over $100,000 annually.

There are numerous opprtunities for recovering waste heat from the following major components of a boiler:

- The boiler itself
- Steam lines and reducing stations
- The deaerator
- The condesate reciever
- The blowdown system

This article will discuss waste heat recovery approaches and the types of

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you generally need about .02 square foot to handle one pound per hour of steam.

Assuming an equipment price of $80 per square foot, the cost of condensing 1000 lbs./hr. of vented steam would be: (1000 lb./hr. x .02 sq.ft/lb./hr. x $80/sq.ft.) or $1600. If we estimate the value of the steam at $6 per 1000 lbs., the condenser would achieve an annual savings of: ($.006/lb. x 1000 lb./hr. x 8000 hr./yr.) or $48,000. It would be difficult to find a more cost-effective investment.

TABLE 6 — Economic Analysis of a Blowdown Heat Recovery Project*

Boiler size — 800 hp
Fuel cost — $0.39 per therm
Boiler total dissolved solids — 2500 ppm
Makeup total dissolved solids — 250 ppm
Percent condensate return — 50 percent
Blowdown recovery heat exchanger— used without flash tank
Efficiency of energy recovery — 93 percent
Blowdown rate — 6.7 gpm
Energy recovery rate — 11.86 therms per hr
Dollar saving per year — $27,752
Equipment cost — $6,635
Payback — 3 months
ROI — 418%

*Based on data supplied by Sentry Equipment Co. and is used with permission.

Recovering heat from blowdown

All boilers having continuous skimming blowdown and requiring significant makeup water (say 5 percent) are good candidates for blowdown waste heat recovery. Blowdown contains a significant amount of heat energy, most of which can be captured and reused.

If you have a boiler pressure over 100 psi and a direct process use for flash steam, you should consider using a flash tank. This tank causes some of the blowdown water to flash to steam, which can then be used for both the process and preheating feedwater. Such a system could recover 50 to 60 percent of the energy released in blowdown.

When pressures are less than 200 psi, however, we find the most economical heat recovery approach is usually just to use a shell-and-tube or plate type heat exchanger, without a flash tank.

For boilers with higher pressures, a combination flash tank/heat exchanger (as shown in Figure 4) may be justified. Figure 5 indicates the percentages of efficiency (energy) loss that result from various amounts of blowdown at different boiler pressures. A heat exchanger/flash tank system can eliminate about 90 percent of this loss.

In general, a blowdown heat recovery system is one of the most attractive investments you can make in a boiler room, usually achieving payback in less than one year. A cost-savings analysis of a typical blowdown recovery heat exchanger project, without the use of a flash tank, is presented in Table 6. In this example, the rate of return (ROI) on an investment of $6,635 is calculated to be 418 percent — for a payback in only three months.

Figure 6 shows a hypothetical boiler plant in which all the various opportunities for capturing waste heat have been applied. Not all of these opportunities, of course, are applicable in every situation. We have found, however, that the typical plant, by employing several of the appropriate techniques, can save at least five percent of its boiler fuel costs.

David Dyer, Ph.d., P.E., is a professor of mechanical engineering at Auburn University and president of the Boiler Efficiency Institute. He has consulted extensively with industry on combustion technology, has developed new equipment for burning wood, and has designed and implemented efficiency improvement programs for boilers and other combustion equipment for numerous industrial concerns.

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TABLE1—Acid Dewpoint Levels (Minimum Stack Temperature To Avoid Acid Condensation)

Fuel	Minimum Stack Temperature
Propane or Natural Gas	250 F
Low Sulfur Oil*	275 F
High Sulfur Oil**	320 F
Coal**	325 F
Wood	310 F

*Sulfur less than .5%
**Sulfur levels from .5 to 2%

TABLE 2—Annual Dollar Savings In Typical Economizer Installations*

	Fuel		
Boiler Size	Gas ($6/million Btu)	#6 oil ($4.5/million Btu)	Coal ($2.00/million Btu)
100 HP	8,106	3,754	1,669
500 HP	40,531	18,768	8,343
1,000 HP	81,061	37,536	16,687
50,000 lb/hr	117,480	54,500	24,222
100,000 lb/hr	234,960	109,000	48,444
500,000 lb/hr	1,174,800	545,000	242,222
1,000,000 lb/hr	2,349,600	1,090,000	484,444

*Assumes: Initial boiler efficiency 75%, a pressure of 85 psi, stack temperature 100 F over steam temperature, economizer outlet temperature minimum, load 66% of maximum, 8000 hours of operation.

FIGURE 2 Finned Tube Economizer

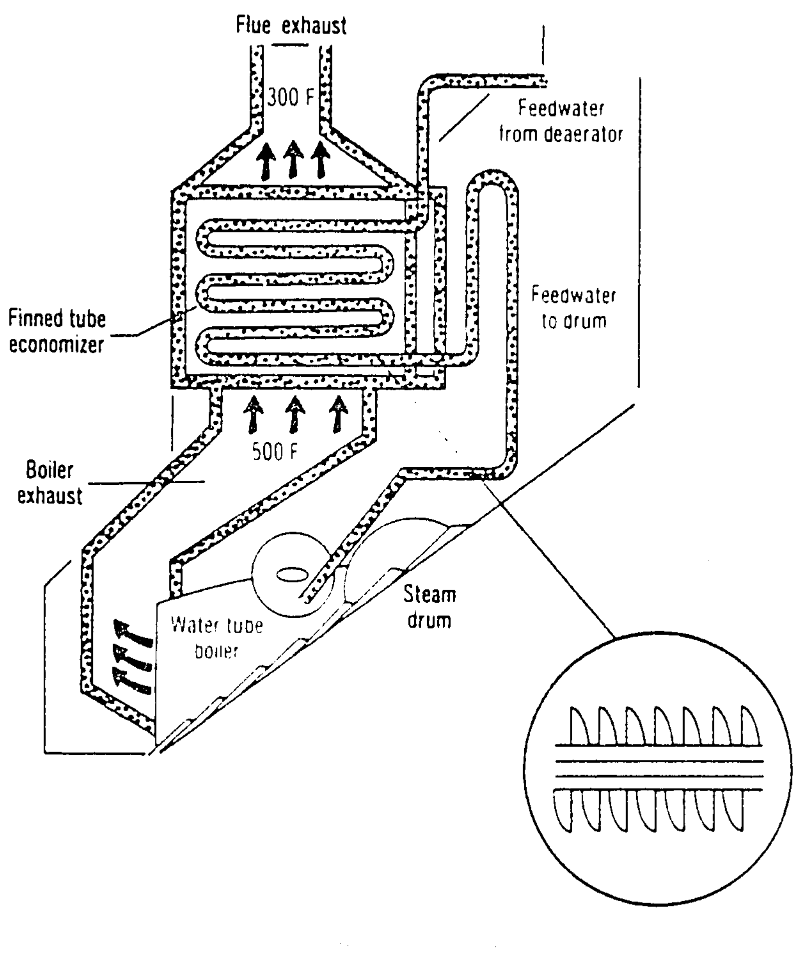


TABLE 3—Power Output From a Back Pressure Turbine in Btu/lb. of Steam*

Outlet Pressure, Psi	Turbine Inlet Pressure			
	200 psi	400 psi	600 psi	800 psi
50 psi	81.1	119.2	140.3	153.6
100 psi	42.2	82.5	105.0	119.3
200 psi		43.1	66.8	82.4
300 psi		18.2	43.0	59.4

*Assumes a 75% turbine efficiency.

which it is installed, and more testing of this type of economizer needs to be done.

When determining whether an economizer is required, you must recognize that high stack temperatures can result from fouling on the fire or water side of the boiler, excess air, or an insufficient heat transfer surface. Only in the last case should you consider using an economizer.

In higher pressure boilers or situations where little makeup water is needed for the boiler, you can use an air preheater. The same guidelines for energy savings and minimum stack temperatures that apply to economizers also apply to air preheaters. Usually, an economizer is the least expensive heat exchanger per unit of energy saved. But, when little energy needs to be added to the makeup water, you should use an air preheater.

One more approach to lowering flue gas temperature and indirectly capturing waste heat for firetube boilers is to use turbulators — twisted strips of metal inserted into the tubes of a firetube boiler (see Figure 3). These strips increase turbulence and heat transfer in some cases, thereby lowering stack temperatures. They also offer resistance to flow and about equalize flow rates through the tubes, which further increases heat transfer efficiency. Although turbulators have the effect of reducing excess air and lowering stack temperature, the resulting savings cannot be attributed completely to the turbulators since damper adjustment would accomplish the same effect.

Some turbulator manufacturers claim savings of 15 percent or more, but these claims are not valid because they can be achieved only by making other adjustments. Data we've obtained at the Boiler Efficiency Institute indicate a maximum savings potential of three percent — and then only under the right conditions. We've found that turbulators achieve their best results in single or double-pass natural gas-fired boilers with tube diameters in excess of two inches. They also tend to alleviate the problems of deposit buildup and corrosion.

Recovering heat from a reducing station

Many plants have reducing stations or boilers capable of generating steam at pressures higher than process requirements. In such cases, you can install a back pressure turbine to drop the pressure to the level needed for the process and also produce power that can be used to generate electricity or directly drive a load.

For a back pressure turbine to be profitable the power output and all the exhaust steam from the turbine must be utilized. We've found numerous turbine applications where exhaust steam is used for the deaerator, then much of it is allowed to vent. In such instances, the economic value of the back pressure turbine is negated.

Table 3 shows the amount of power that can be generated with a back pressure turbine given various inlet and outlet pressures This table assumes a 75-percent turbine efficiency but does not take into consideration the extra steam energy that must be produced to satisfy process requirements when a back pressure turbine is used. A typical example of the economics of a back pressure turbine application is presented in Table 4. In this example, the cost of the turbine generator installation is paid back in about eight months in the value of usable electric power produced.

Recovering heat from deaerators and condensate tanks

Any time the pressure of hot condensate is reduced, such as when it is brought back to a low pressure condensate receiver or deaerator, a certain amount of the hot liquid will flash to steam. The amount of steam venting from a condensate receiver or deaerator depends on the condensate pressure, the pressure to which it is dropped and the amount and temperature of the makeup water added to the condensate. Table 5 gives an indication of how much condensate is vented due to flashing from various pressures to atmospheric, based on the addition of different amounts of 70F makeup water.

One way to capture this vent steam from a deaerator or condensate receiver is to use a vent condenser — a shell-and-tube or plate-type heat exchanger that preheats water or air while condensing the vented steam. This type of equipment typically costs \$20 to \$100 per square foot of heat transfer surface depending on overall size, materials and other factors, and

FIGURE 3 Turbulators Installed in Firetube Boiler

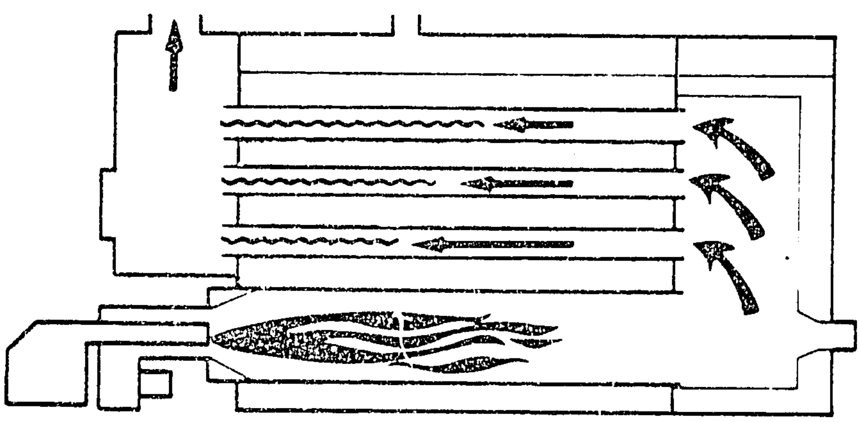


FIGURE 4 Blowdown System with Flash Tank and Heat Exchanger

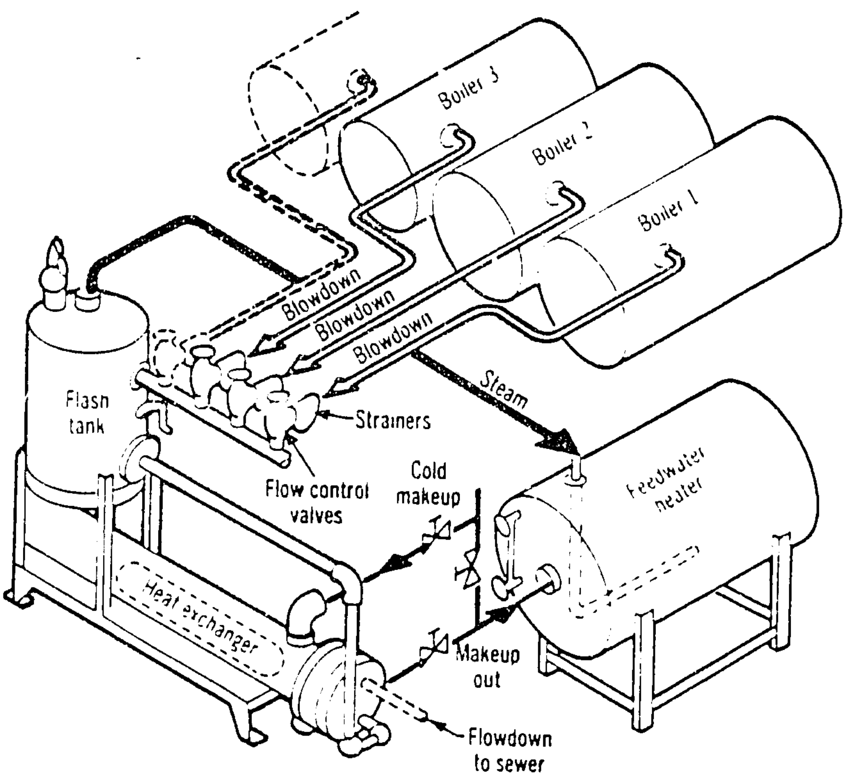


TABLE 4—Economics of a Back-Pressure Turbine Application*

Boiler pressure — 650 psig
Process pressure — 50 psig
Process requirement — 35,000 lb/hr
Additional steam required due to installing turbine — 2760 lb/hr
Steam cost — $4.50/1000 lb
Annual cost of additional steam — $101,105
Value of electric power produced per year at 3.5¢/KWH — $282,100
Energy saving per year — $181.,995
Cost of turbine/generator — $125,000
Payback period — 8 months

*Based on data supplied by Terry Steam Turbine, Windsor, Conn., and used with permission.

FIGURE 5 Efficiency Loss Due to Blowdown

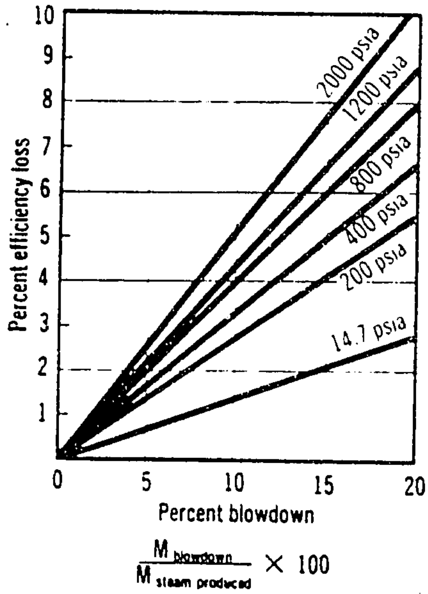
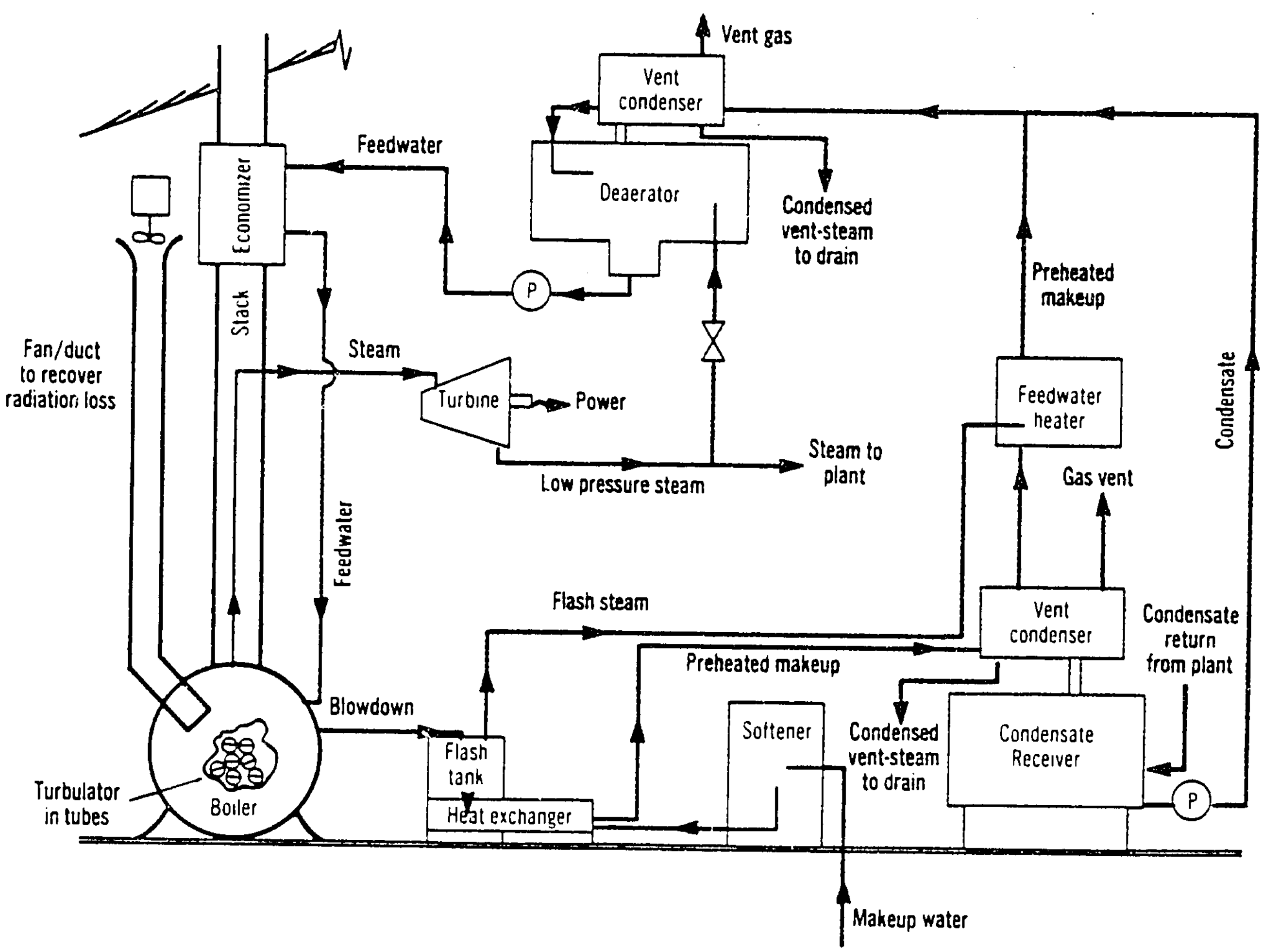


TABLE 5—Percent of Condensate Flashed Due to Dropping Pressure to Atmospheric

% Makeup*	Condensate (Saturated Liquid) Pressure, psi 50	100	150	200	250	300
0	7.2	12.2	15.5	18.1	20.2	22.1
20	4.4	9.4	12.7	15.3	17.4	19.3
40	1.6	6.6	9.9	12.5	14.6	16.5
60		3.8	7.1	9.6	11.8	13.7
80		1.0	4.3	6.9	9.0	10.9
100			1.54	4.1	6.2	8.1

$$\text{*\% Makeup} = \frac{\text{lb of makeup}}{\text{lb condensate}} \times 100$$

FIGURE 6 Typical Flow Diagram for Boiler Plant with Heat Recovery (not to scale)



equipment available, including an evaluation of their advantages, limitations and approximate energy savings. In each case, careful engineering is required to insure the appropriateness and proper application of the heat recovery equipment.

Capturing radiation loss

A simple approach to recovering heat from the boiler itself is to capture radiation loss, the heat that builds up on the outside surface of a boiler and is lost to the surroundings.

The amount of radiation loss varies widely by boiler design. If the boiler is designed so that water circulates between the hot combustion gas and boiler outer surface (a "wet back" boiler), radiation losses are typically one percent of fuel input at full load. On the other hand, dry back boilers which utilize refractory lining show radiation losses typically ranging from two to four percent of fuel input at full load. As the load decreases, this loss percentage becomes much larger.

Air heated by radiation loss rises to the top of the boiler room. Conventional boiler room designs make it difficult to recover this waste energy. Such designs (as shown in Figure 1A) usually include ceiling vents, for exhausting the hot air, and combustion air inlet vents located at a lower elevation. Figure 1B shows a more efficient alternate arrangement in which the upper vents are closed, combustion air is brought in at an intermediate level, and a duct is connected to the boiler combustion air intake to pull in the air heated by radiation loss from near the boiler room ceiling. Each 40F the combustion air is preheated by this energy recovery process yields approximately a one percentage point increase in boiler efficiency.

Even more heat can be recovered if you place the duct, used to draw hot air from the ceiling area in to the boiler, around the stack as shown in figure 1C. Using this approach, however, you must be careful not to drop the stack temperature below the "acid dewpoint" levels shown in Table 1. You must also make sure the duct is designed to provide sufficient combustion air for maximum boiler load.

Recovering heat from flue gas

Flue gas leaving a boiler is usually hotter than the minimum allowable temperature, which means the energy content of the flue gas dumped to the atmosphere is higher than necessary. You can use an economizer or an air preheater to reduce the stack temperature and recover this waste heat.

When using conventional heat recovery equipment, such as the finned-tube heat exchanger shown in Figure 2, it is necessary to hold exhaust temperatures above the acid dewpoint, (See Table 1) to prevent acids from condensing on metal surfaces and corroding the recovery systems. Temperatures indicated in Table 1 are nominal values. Consult specific vendors regarding exact requirements for particular applications.

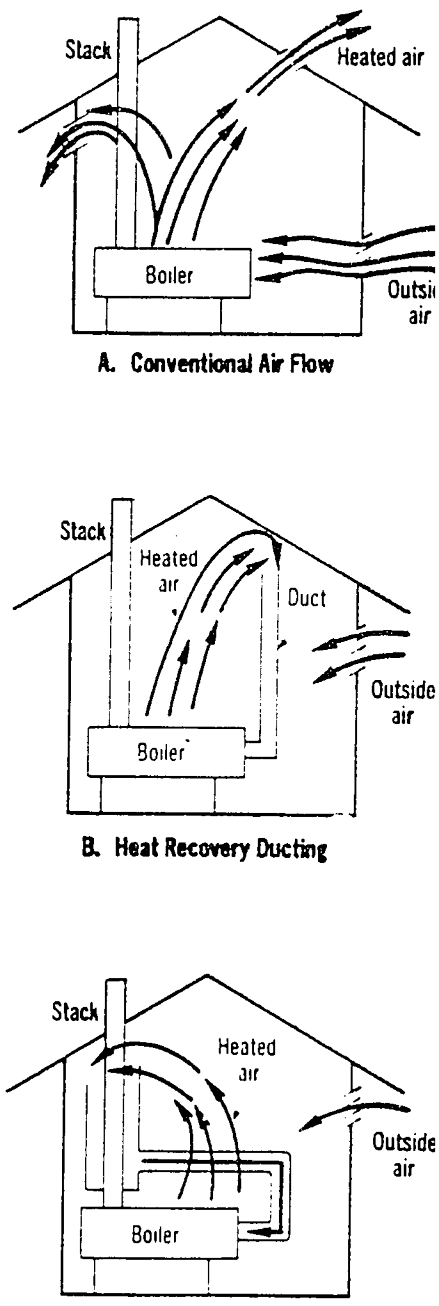
The fin spacing in a finned-tube device is also critical in relation to the fuel burned. Fuels such as heavy oil and coal, for example, require wider fin spacing in addition to soot blowers to keep the fins clean.

Table 2 shows the annual dollar savings possible with typical economizer installations in different size boilers operating on the average of 66 percent of rated capacity for 8,000 hours. The table assigns fuel prices to gas, no. 6 oil and coal and further assumes a pressure of 85 psi, a 75-percent initial boiler efficiency, a stack temperature of 100F over steam temperature and the minimum economizer outlet temperature. Given these parameters, a boiler producing 50,000 lbs./hr. of steam can save $117,480 in gas costs, $54,500 in fuel oil and $24,222 in coal. Higher loads or pressures than those assumed in the table would offer even greater savings.

Also available are unconventional economizers which allow the stack temperature to be dropped below the acid dewpoint. Some of these newer economizers drop the stack temperature to approximately 150F and remove most of the sensible ("temperature") energy from the flue gas. The cost of this type of economizer is approximately the same as the boiler on which it is placed.

Another economizer design sprays water into the flue gas and removes both the latent energy (energy given up when water vapor changes to liquid) and sensible energy from the flue gas by condensing the water vapor generated by combustion of the hydrogen in the fuel. Such a system could also easily boost boiler efficiency by 10 percent — three to seven percentage points more than a conventional economizer. However, it could also cost more than the boiler on

FIGURE 1. Capturing Radiation Loss



A. Conventional Air Flow

B. Heat Recovery Ducting

C. Heat Recovery Ducting on Stack

How You Too Can Save BIG BUCK$ in Boiler Fuel

by David Dyer

Boiler owners are taking a hard look at ways to hold down energy costs. The first step, a boiler efficiency audit, must also be repeated at regular intervals to make sure initial efficiency gains don't evaporate. Here are some typical energy-saving opportunities your boiler audit may turn up. Part I of a four-part series on boiler efficiency improvement.

The usual method used by management in conducting boiler audits is to rely on second-hand information of a general nature provided by operating supervisors, operators and vendors. After reviewing over 1,000 boiler plants, we find this approach typically results in a boiler fuel loss of 10 to 15 percent.

With today's significantly increased costs of boiler fuels in relation to income and profits, management must take control of this situation and optimize boiler efficiency. The key weapon in any boiler efficiency arsenal? The Audit.

Management also needs to recognize that a boiler audit is not something to be done once, then forgotten. Because operating conditions are always changing, it is necessary to audit boiler plants on a continual basis. The first audit may need to be more extensive, since it is the basis for bringing boilers to peak efficiency. But subsequent audits are essential to maintaining this efficiency.

From actual field audits and tests, we find the following actions offer the greatest opportunities for improving the energy efficiency of your boiler operations. Table 1 shows how much money can be saved annually by improving the efficiency of a boiler by 5 percent.

Reduce combustion excess air

Excess air means there is more air than necessary for complete combustion. This extra air is heated up and thrown away, usually wasting a large amount of energy. Two separate actions are required to correct this problem: reducing both the amount of air supplied for combustion ("minimum excess air") and the extra air or excess over minimum (the "excess air cushion"). (See Figure 1.)

As Figure 1 shows, for safety reasons, a certain minimum amount of excess air is required to keep combustibles out of the boiler flue gas. The closer to absolute minimum excess air, the higher the combustion efficiency. Unless a sophisticated control system is use it is not possible to operate a boiler at "minimum excess air." Hence a small "cushion" of excess air must be used.

The minimum air amount is determined by the design and maintenance of the burner/control system as well as the boiler settings (dampers, atomizing pressure, etc.) Using extra air results from lack of attention to the air/fuel ratio. More frequent monitoring and adjusting of the air/fuel ratio will allow a smaller excess air cushion to be maintained. This could be accomplished with an automatic trim control system based on the monitoring of oxygen or combustibles. Oxygen trim systems are usually economical on oil/gas-fired boilers operating at an average output of 15,000 lb. of steam per hour. Combustible trim systems are economical

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at about double this output rate of steam.

Table 2 indicates possible levels to which excess air may be controlled in well-designed combustion systems fired with natural gas, no. 2 oil and no. 6 oil. Certain low excess air systems can perform with even less excess air than indicated in the table and some systems (such as natural draft air supply) will require more air. Also, the closer you try to keep excess air to the minimum, the more often you must adjust it to avoid sooting.

Typical annual savings you can realize from a 5-percent reduction in excess air range from $11,500 on a 100-hp boiler to about $133,333 on a 40,000 lb/hr steam boiler, given fuel costs of $5.00 per million Btu.

Install economizer

For greatest fuel efficiency, flue gas should exit at the lowest temperature possible while avoiding corrosion due to condensation of acids in the stack. This minimum temperature depends on the type of fuel burned. Typical lower limits are: 250F for natural gas, 275 for low sulfur oil and 300F-325F for heavy oil, wood and coal.

There are economizers (heat exchangers) now on the market designed to drop stack temperatures to less than 150F, but there is not yet enough operating data available to evaluate these new systems thoroughly.

In general, for each 40F the stack temperature is reduced by an economizer, an efficiency gain of one percentage point will be achieved. If the stack temperature is high because of high excess air or fouled heat transfer surfaces, however, you should correct these conditions before considering an economizer.

On firetube, one and two-pass boilers with tubes of two inches diameter or more, turbulators may be able to improve efficiency by 2 or 3 percentage points and should be considered rather than an economizer. And an air preheater can be used in place of an economizer on any boiler, if it proves to be more economical.

A typical efficiency improvement of three percentage points resulting from the installation of an economizer produces an annual savings of about $6,900 on a 100-hp boiler and $80,000 on a 40,000-lb/hr boiler, given fuel costs of $5.00 per million Btu.

TABLE 1
Dollars Saved Annually by Improving Boiler Efficiency by 5 percent

STEAM PRODUCTION	FUEL PRICE				
	$3.00* or 45¢/gal	$4.00* or 60¢/gal	$5.00* or 75¢/gal	$6.00 or 90¢/gal	$8.00 or $1.20/gal
100 HP or 3,450 lb/hr	$ 6,900	$ 9,200	$ 11,500	$ 13,800	$ 18,400
200 HP or 6,900 lb/hr	$ 13,800	$ 18,400	$ 23,000	$ 27,600	$ 36,800
400 HP or 13,800 lb/hr	$ 27,600	$ 36,800	$ 46,000	$ 55,200	$ 73,600
800 HP or 27,600 lb/hr	$ 55,200	$ 73,600	$ 92,000	$ 110,400	$ 147,200
40,000 lb/hr	$ 80,000	$ 106,667	$ 133,333	$ 160,000	$ 213,334
60,000 lb/hr	$ 120,000	$ 160,000	$ 200,000	$ 240,000	$ 320,000
80,000 lb/hr	$ 160,000	$ 213,334	$ 266,667	$ 320,000	$ 42[illegible],668
100,000 lb/hr	$ 200,000	$ 266,666	$ 333,333	$ 400,000	$ 533,332
200,000 lb/hr	$ 400,000	$ 733,333	$ 666,667	$ 800,000	$1,466,666
300,000 lb/hr	$ 600,000	$ 800,000	$1,000,000	$1,2[illegible]0,000	$1,600,000
400,000 lb/hr	$ 800,000	$1,066,666	$1,333,333	$1,600,000	$2,133,332
500,000 lb/hr	$1,000,000	$1,333,334	$1,666,667	$2,000,000	$2,666,668
1,000,000 lb/hr	$2,000,000	$2,666,667	$3,333,333	$4,000,000	$5,333,334

*Price in $/millions BTU or $/1000 cubic foot of gas.

FIGURE 1.
Explanation of Excess Air

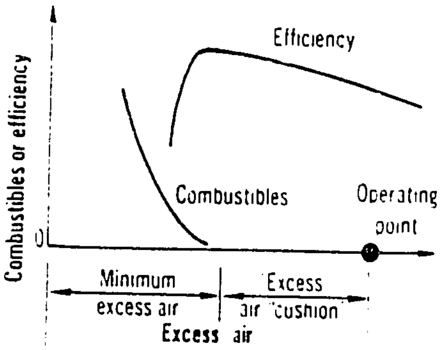
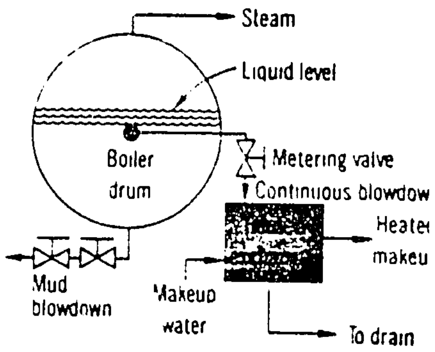


FIGURE 2.
Blowdown System



Control scale for energy savings

Scale or deposits serve as an insulator, and, as deposits build up, they cause increasing amounts of heat from the flame to go up the stack instead of into the water. A rule of thumb is that every 1/64 inch of scale will reduce heat transfer, and consequently boiler efficiency, by one percentage point.

Improper water treatment leads to the formation of scale on the water side of a boiler. If your boiler cannot be cleaned by high pressure water, then the treatment is a failure. A chemical vendor backed by a company you know to be reputable should be retained to straighten out your program.

The right starting point is to be sure that all makeup water is conditioned by a sodium zeolite softener or equivalent. The cleanest system results from using chelating agents; however, their corrosiveness mandates they be carefully controlled.

Reduce blowdown

Another common area for efficiency loss is the blowdown system

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FIGURE 3.
Blowdown System with Flash Tank and Heat Exchanger

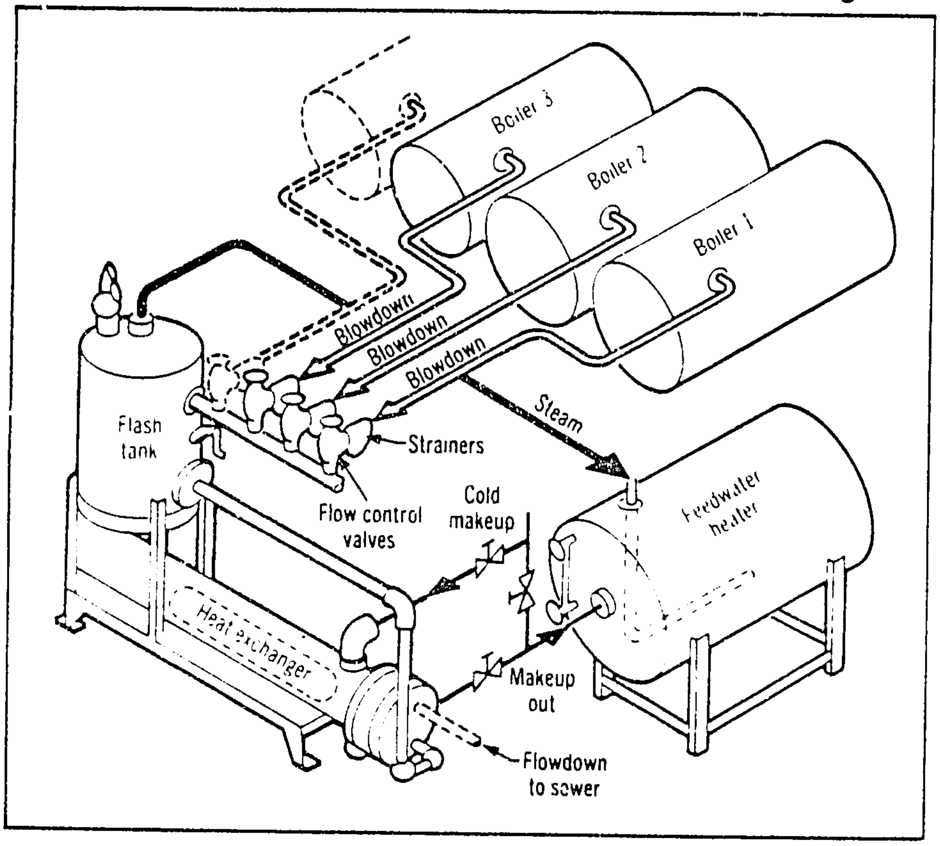
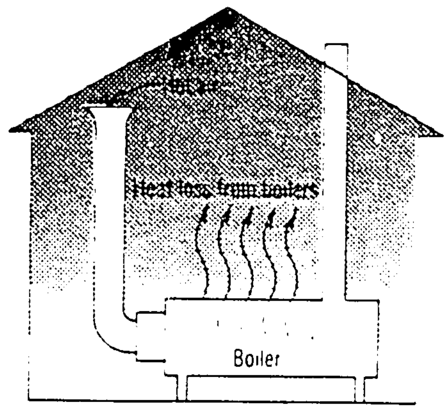


TABLE 2
Control of Excess Air

On well-designed systems, the following levels of excess air are possible:

Fuel	Excess Air Level
Natural Gas	10%
No. 2 Oil	12%
No. 6 Oil	15%

FIGURE 4.
Schematic of Ducting to Preheat Combustion Air



(See Fig. 2). There are two types of blowdown. Continuous or skimming blow operates continually to remove the light dissolved solids that build up in the boiler near the top of the water level, at the liquid/vapor interface. And mud blow, which must be done for a few seconds every several hours, is designed to remove heavy suspended solids that have settled to the bottom of the boiler.

Excessive blowdown results in the loss of large amounts of energy, since you are actually dumping hot water from the boiler into the sewer, unless of course you install some type of energy recovery equipment. Two factors especially can contribute to excessive blowdown — use of mud blow only and poor water quality.

Many boilers are blown entirely by mud blow because the continuous blowdown system has never been connected. This results in poor collection efficiency, requiring the removal of most of the boiler water just to get rid of the light solids near the top.

Any boiler with 5-percent makeup water or more should have a continuous skimming blowdown. Boilers blown entirely by mud blowdown lose at least one percentage point in boiler efficiency because of the excessive amount of water removed. In fact, for the greatest fuel efficiency, you should determine when mud blowdown is actually needed by measuring the amount of "mud" in the water, rather than blowing the system at fixed time intervals.

Another reason for excessive blowdown is that many managements accept water treatment programs designed for simplicity and low first cost. This complicates the job of operators who must maintain water quality parameters as close as possible to designated tolerances. Otherwise "total dissolved solids" (TDS), for example, are maintained at one half the allowable value, blowdown will be twice the required amount. Or if alkalinity is near its maximum value while TDS is much less than its limit, you can significantly reduce blowdown by changing the water treatment process. You should consult a water treatment expert.

Recover waste heat

All boilers with continuous blowdown which operate most of the year should have a blowdown waste heat recovery system, as shown in Figure 3, to capture the heat from the blowdown and use it to heat makeup water.

A schematic of a typical heat recovery system is presented in Figure 3. Such a system generally improves boiler efficiency by one to two percentage points and pays back the investment in less than six months.

A different type of heat recovery, which simply involves using the natural build-up of heat from the boilers in the boiler room to preheat air coming into the boiler, will usually add 1 to 1.5 percentage points in boiler efficiency. Figure 4 shows a typical installation.

Note the air intake to the boiler should be near the ceiling of the boiler room to draw in heat escaping from the boiler, heat which naturally tends to rise to the ceiling. Be careful in extending the air intake ducting, however, to assure that sufficient fan capacity exists in the face of this added resistance.

Stop on-off operation

Many boilers are ten to twenty times larger than necessary for the

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TABLE 3
Annual Savings Possible With Use of 1″ Fiberglass Jacket Insulation*

Cost of Natural Gas		$2.00 Million BTU's	$4.00 Million BTU's	$6.00 Million BTU's	$8.00 Million BTU's	$10.00 Million BTU's
Cost of Fuel Oil		30c Gal.	60c Gal.	90c Gal.	$1.20 Gal.	$1.50 Gal.
Gate Valve Size	2″	$ 31	$ 62	$ 93	$124	$155
	4″	$ 58	$117	$175	$233	$292
	6″	$ 86	$171	$257	$343	$429
	8″	$113	$226	$339	$452	$565
	10″	$140	$281	$421	$562	$702

*Similar savings could be expected from valves and fittings of other sizes. Annual Savings were calculated assuming steam cost at 1.5 times fuel cost due to boiler efficiency, chemical costs, etc.

study to determine minimum pressures required during different seasons of the year.

Since pressure also sets the water temperature in a boiler producing saturated steam, reducing steam pressure and temperature yields a number of savings. These savings include lower stack temperature due to improved heat transfer, less heat loss from the cooler boiler skin, less heat loss from cooler uninsulated steam pipes and fewer steam leaks.

Process requirements, however, generally dictate steam pressure. You might consider operating with a sliding pressure if conditions vary, such as in heating a building. If the boiler is a water-tube type, the manufacturer should be consulted before you drop pressure. It might even be economical to redesign a steam distribution system to allow one boiler to supply low-pressure requirements and another boiler to supply the higher-pressure requirements.

Make repairs

The baffles for directing the flow of combustion gases become warped on many boilers, allowing gas to bypass the convection heating area in the boiler. This problem, if not corrected, results in high stack temperatures and hot layers of gas in the flue. Warped baffles are usually the result of overfiring boilers or bringing them up from a cold start too rapidly.

Leaks through the boiler casing, if not repaired, will either allow hot gas to escape into the boiler room or cold, damp air to leak into the boiler. In either case, efficiency is reduced. To minimize this effect, adjust furnace pressure to near zero.

You should also keep burner tips clean to minimize the amount of excess air required for complete combustion. In addition, damaged orifices or other burner parts such as throat refractory must be repaired.

Any visible leak of hot water, air or steam should be stopped immediately. Likewise, all steam traps should be checked and repaired as required to stop invisible leaks. Eliminating these losses could easily represent the largest potential savings.

Insulate all hot surfaces

All surfaces hot to the touch should be insulated unless equipment would be damaged. This includes hot valves, flanges, traps, ends of boiler drums, etc. The payback of adding one inch of insulation to a 200F bare surface typically is less than one year.

Common examples of uninsulated surfaces are valves and traps. Because these elements must be repaired and replaced frequently, it is customary not to insulate them. We recently conducted a research program to determine the savings from insulating valves with a jacket-type insulation. Table 3 summarizes the results of that study.

Tune deaerator

Many deaerators are mechanically defective, and should be checked often and repaired as necessary. And, you should adjust the vent valve to keep the steam plume leaving the deaerator to the minimum level required to remove oxygen.

Installing a vent condenser to capture waste steam generally offers a fast payback in those situations where vent steam is difficult to control. In general, it is impossible to properly control the vent loss from a deaerator without a modulating makeup water feed pump.

The preceding areas focused on give an indication of some actions you could take to improve boiler efficiency. By conducting the necessary audits, you can pinpoint problem areas that need your immediate and continuing attention.

Computerized boiler audits

At the Boiler Efficiency Institute in Auburn, Alabama, we have developed a computerized audit program for boiler plants. This audit program evaluates existing boiler performance based on the input of a small amount of data. It then makes an evaluation of the savings and costs that would result from various actions: reducing excess air, recovering waste heat from stack gas, reducing blowdown and recovering waste heat from blowdown.

Remember, the efficiency improvement from any given action will usually be small, but together they add up fast. Your continued work on all areas of a boiler operation will produce significant cost savings in purchased fuel. ●

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ECONOMIC EVALUATION OF BOILER EFFICIENCY IMPROVEMENT PROJECTS (BY PLANT)

EFFICIENCY IMPROVEMENT PROJECT	ANNUALIZED SAVINGS (1979 $)	ESTIMATED IMPLEMENTATION COST (1979 $)	SAMPLE PAYBACK PERIOD (YEARS)
PLANT A (New York—machining and assembly operation)			
Excess Air Control	44,718	50,000	1.12
Economizer/ Fouling Removal	9,438	20,000	2.12
Air Preheating	5,346	5,000	0.94
Other: Fix Leaks	40,000	90,000	2.25
Subtotals:	99,502	165,000	1.66
PLANT B (Connecticut — development lab)			
Excess Air Control	370,834	80,000	0.22
Economizer/ Fouling Removal	110,623	190,000	1.72
Load Management	77,000	—	immed.
Air Atomization	58,200	25,000	0.43
Subtotals:	616,657	295,000	0.48
PLANT C (Connecticut — electronics manufacturing)			
Load Management	21,000	—	immed.
Air Atomization	16,443	1,000	0.06
Subtotals:	37,443	1,000	0.03
PLANT D (Canada — machining and assembly operation)			
Excess Air Control	42,788	40,000	0.93
Subtotals:	42,788	40,000	0.93
PLANT E (Connecticut — machining and assembly operation)			
Excess Air Control	92,035	100,000	1.09
Economizer/ Fouling Removal	21,396	40,000	1.87
Load Management	22,000	—	immed.
ir Preheating	6,000	5,000	0.83
ir Atomization	16,800	10,000	0.60
ubtotals:	158,231	155,000	0.98
LANT F (Connecticut — machining and assembly operation)			
xcess Air Control	159,114	120,000	0.75
conomizer/ Fouling Removal	83,784	80,000	0.96
lowdown Recovery	10,612	10,000	0.94
ir Preheating	8,250	5,000	0.61
ir Atomization	12,000	10,000	0.83
ubtotals:	273,760	225,000	0.82
PLANT G (Connecticut — machining and assembly operation)			
Economizer/ Fouling Removal	54,846	127,446	2.32
Air Atomization	16,800	10,000	0.60
Other: Combustion Controls	62,420	100,000	1.60
Subtotals:	134,065	237,446	1.77
PLANT H (Connecticut — machining and assembly operation)			
Load Management	30,000	—	immed.
Air Preheating	9,500	5,000	0.53
Air Atomization	23,558	15,000	0.64
Subtotals:	63,058	20,000	0.32
PLANT I (Connecticut — machining operation)			
Excess Air Control	17,468	15,000	0.86
Air Preheating	5,400	5,000	0.93
Air Atomization	16,404	10,000	0.61
Subtotals:	39,272	30,000	0.76
PLANT J (Connecticut — machining operation)			
Excess Air Control	12,000	10,000	0.83
Air Atomization	5,116	10,000	1.95
Subtotals:	17,116	20,000	1.17
PLANT K (Florida — development center)			
Excess Air Control	205,000	710,000	3.5
Air Atomization	10,000	10,000	1.0
Subtotals:	215,000	720,000	3.3
PLANT L (Connecticut — electronics manufacturing)			
Economizer/ Fouling Removal	26,250	25,000	0.95
Blowdown Recovery	5,968	6,000	1.00
Subtotals:	32,218	31,000	0.96
TOTALS	1,729,111	1,939,446	1.12

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amount of steam required. This results in extra heat loss from the boiler surface and losses due to purging and convection cooling of the boiler while it is off. If the boiler capacity greatly exceeds demand for two or three months or more per year, it usually will be economical to replace the larger boiler with a smaller one for this period.

Making certain changes in any boiler which either stays off a significant amount of time or continually varies in firing rate can improve its efficiency. For example, changing burner tips in boilers that operate intermittently may reduce the firing rate. But this alone may not improve efficiency, if you do not maintain excess air at the same or lower level.

Another approach is to set the boiler to fire at an intermediate rate, instead of at a high firing rate. This will allow the boiler to stay on longer. However, excess air must be carefully controlled. Usually, the most economic action is to purchase a small boiler to operate when limited amounts of steam are required.

Switch from steam to air

In some cases, more frugal use of the steam itself can increase the fuel efficiency of your boiler system. For example, air, properly used, produces atomization equivalent to steam. And because air contains much less energy per pound, switching from steam to air atomization generally lowers fuel costs by one-half to one percentage point, even considering that the electricity required costs more than fossil fuel.

It is also wise to consider switching from steam to air soot-blowing, when the burning of heavy fuel oil or solid fuels necessitates periodic cleaning of heat transfer surfaces. In the case of oil-fired boilers, it is generally cheaper to use air as the media for cleaning.

Reduce steam pressure

Any boiler being operated at a pressure higher than the process requirement offers a potential to save energy by reducing boiler pressure. Many times persons in charge of operations demand an unnecessarily high steam pressure. You should make a careful

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What Boiler Audits Are Doing for UTC

by Charles F. Feledy,
director of corporate energy programs,
United Technologies Corporation

United Technologies Corporation (UTC) authorized engineering audits in 1979 and 1980 of 22 boilers located in 12 major UTC facilities to identify boiler efficiency improvement projects. This effort represents one of the major elements in a successful ongoing energy management program that resulted in UTC's reducing the energy content of its products (measured in Btu per unit of output) by 55 percent through 1980 versus a 1972 baseline.

The boilers audited collectively represented a rated steam generation capacity of 2,113,000 pounds per hour. They ranged in size from 17,500 to 250,000 pounds per hour.

UTC is not an energy intensive company like those in the steel or chemical industries, since it spends only about 1.3 cents out of every sales dollar on energy. However, in absolute terms, it does have a large energy bill; in 1981, UTC spent over $176 million for all forms of energy. To put this large number in perspective, these energy dollars were 49 percent larger than UTC's 1981 dividend payments on its common stock.

When measured in energy units, UTC's 1981 energy consumption was 22.2 trillion Btu. It is estimated that boiler fuel represented about 25 percent of this, or about $44 million in 1981.

Although our divisions and groups had already done an excellent job of improving the thermal efficiency of their boilers, in view of this large fuel bill, corporate management felt it was desirable to use an engineering consultant to conduct formal audits of boiler operations at selected major facilities in order to "fine-tune" boiler performance, upgrade operator skills, and thus, lower fuel costs and improve corporate profitability.

The Boiler Efficiency Institute of Auburn, Alabama conducted a series of one-day audits at each of 12 UTC facilities. And, based on these audits, they made recommendations on eight basic types of boiler improvement projects: load management, air preheating, blowdown recovery, fixing air leaks, adding improved combustion controls, switching to air atomization, reducing excess air and cleaning heat transfer surfaces.

The number of projects identified per plant ranged from a high of five to a low of one and totaled 36 in all. With a total investment, including capital plus expense dollars, estimated at $1,939,466 for implementing all the projects, an annual savings of $1,729,111 was projected. The overall simple payback period is thus a very attractive 1.1 years.

It should be noted that UTC uses the simple payback period as one of the criteria to preliminarily rank proposed capital projects. When it is finally decided to prepare a capital appropriation request, discounted-cash-flow and return-on-investment analysis calculations are used to make the final appropriation decision.

Ranking the Improvement projects in descending order of estimated savings, reducing excess air is clearly first. With estimated savings of $943,957, these projects represent 54.6 percent of total savings. Adding economizer/fouling-removal projects rank second with savings of $306,337 or 17.8 percent of the total. And air atomization is third with savings of $175,321 or 10 percent of the total.

Of the 36 projects defined, the lengths of the payback periods ranged from "immediate" for four load management projects (at Plants B, C, E and H) to 3.5 years for a reducing-excess-air-project (at Plant K). An "immediate" payback means that since the project requires no investment cost to be implemented, the desired results can be obtained immediately. And 20 of the 36 projects, or 55.5 percent of the total, have payback periods not exceeding one year. Also, only one project exceeds a two-year payback.

Almost all of these projects are obviously cost-effective and would meet the capital appropriation "hurdle" rates of most companies for proposed new investments. The table details plant by plant the economics of the boiler efficiency improvement projects recommended as a result of the boiler audits.

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How to evaluate low-excess-air controls for packaged boilers

Use this handbook-type guide to determine the potential for improving efficiency of your single-burner boiler. Learn which trim controllers you can trust to maintain setpoint at the capability of your burner and boiler

By J Bree[illegible]g and S Londerville, Coen Co

There are many types of excess-air trim systems available today in what manufacturers view as a boom market catalyzed by inflated oil prices. For the small boiler owner, determining whether low-excess-air (LEA) firing can be cost-justified and what type of system would be appropriate is a difficult decision requiring a great deal of thought and engineering judgment. And since no two excess-air trim systems are exactly alike in control philosophy, it is very important to select the one that best suits your particular boiler and payback requirements.

Prudent engineers generally recommend an in-depth evaluation of boiler and controls before specification. The starting point for any evaluation should be an analysis of existing heat-transfer characteristics within your boiler so that a reliable estimate of the efficiency gain from LEA firing can be determined. Recall that heat transfer takes place in three main areas of the boiler—the radiant section, convection bank, and heat-recovery equipment (economizers and air heaters). LEA firing alters the normal heat-transfer distribution among these three areas.

As a rule of thumb, 50% of the total energy released in the combustion process is absorbed in the radiant section, 25% in the convection bank, and 5-15% in heat-recovery equipment. Firing at reduced excess air increases the amount of heat transfer in the radiant section and decreases transfer to the convective section.

A simplified approach to examining heat-transfer changes at reduced excess-air levels is the stack-loss method. Initial assumptions are that the burner will perform at LEA levels and that the flame is sized correctly for the furnace. It is possible to perform the heat-transfer analysis for typical packaged boilers and generate approximate stack-temperature reductions as a function of excess-air reduction (Fig 1). The charts in Figs 2 and 3 show stack heat loss as a function of excess air and stack temperature. From these it is possible to determine heat loss as a function of excess air. (Simplified heat-transfer equations are also available from the authors.)

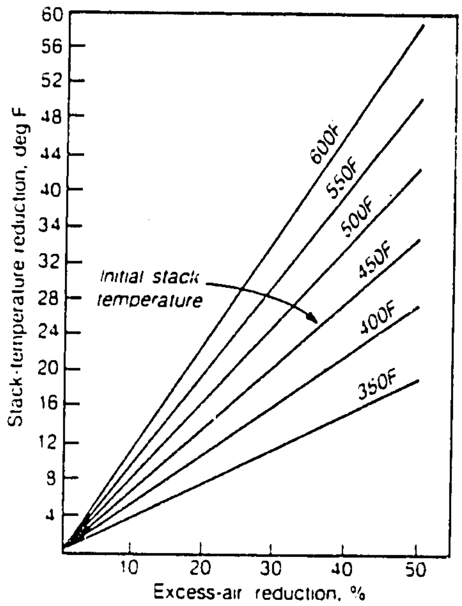
Be aware that certain boilers may not operate well at LEA levels. The following conditions may negate or reverse efficiency advantages of LEA firing:

- **Boilers with convective superheaters** may be affected adversely by reduced mass flow. Superheat temperature may drop, although the amount depends on the boiler and superheater design. Consult the boiler manufacturer.
- **Older boilers,** particularly those with tangent-tube walls, may be susceptible to short circuiting of the flame into the convection section. This situation can make LEA firing very difficult.

Evaluating control systems

Knowing about the heat-transfer characteristics of your boiler, you can estimate efficiency increases based on boiler/burner tuning and burner replacement; the full rewards of LEA firing, however, are unattainable without suitable controls. Unlike most equipment, LEA control-system specifications can be used to obtain only ballpark performance figures. Reason is that changing environmental and mechanical factors affect boiler performance constantly.

All combustion controls attempt to



1. Heat-transfer analysis should lead off any evaluation of LEA firing

maintain a nominal air/fuel ratio as a function of firing rate. This ratio is approximately correct only under conditions at the time of startup. If all system variables and external conditions remained constant, and the system had no hysteresis or errors, it might be possible to adjust the controls to operate near the optimum excess-air level

Other highly variable conditions may affect air/fuel ratio on a daily basis. On the air side, atmospheric changes such as barometric pressure, humidity, air temperature, and wind velocity may throw calibration off. On the fuel side, slight variations in supply pressure, temperature, and heating value cause changes in air/fuel ratio.

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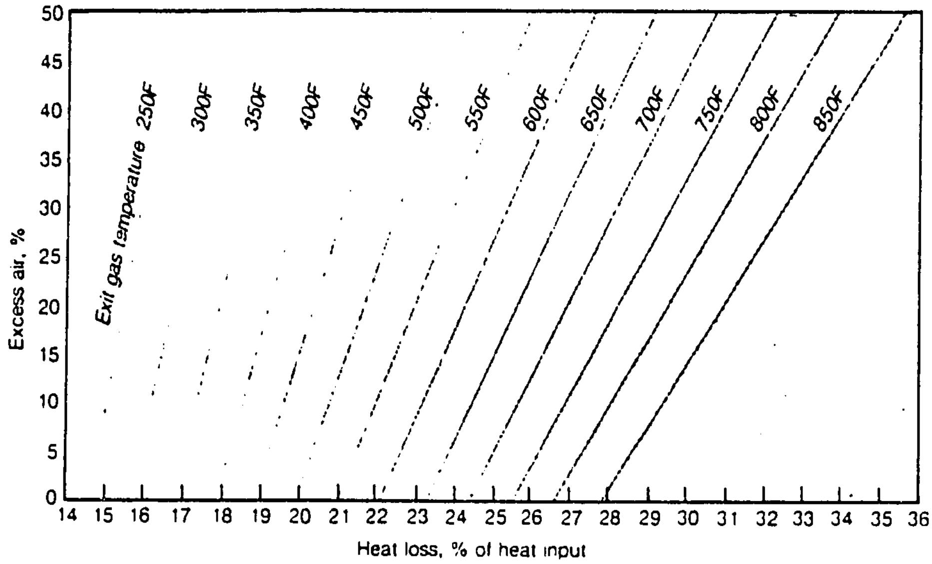
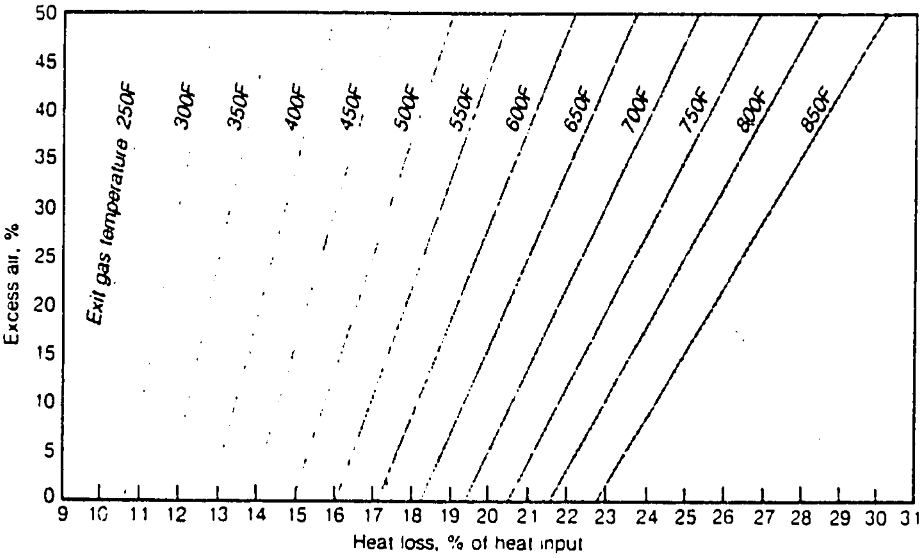


2-3. Stack-loss method simplifies examination of heat transfer at LEA levels. Assuming that a burner operates at LEA levels and that flame is sized correctly for the furnace, it is possible to estimate stack-temperature reductions as a function of excess air for boilers firing gas (above) and oil (below). Efficiency can be approximated by adding 2% to stack loss and subtracting this from 100%



Heat losses include those caused by heat carried away in dry flue gas, moisture formed in the burning of hydrogen, and moisture in the combustion air (0.013 lb H_2O/lb combustion air)

Even some of the primary elements of a combustion-control system may contribute significantly to poor firing conditions. Damper linkages may flex slightly, and bearings may wear out over time. Even metering systems are susceptible to some error, since their flow transmitters are operated at temperatures and pressures that vary significantly from those at which the transmitters were initially calibrated.

During operation, these potential errors combine randomly to alter the expected air/fuel ratio. To ensure that the ratio does not escalate to inefficient fuel-rich conditions within the boiler, most combustion-control systems are set up to operate with an excess-air cushion to account for the worst possible combination of errors in the system.

Hypothetically, if the combustion-control system had the ability to account for momentary variations in operating conditions by adjusting fuel/air ratio, then the boiler could operate at optimum efficiency with ideal flame conditions. This is the objective of excess-air trim systems—to reduce the excess-air cushion as much as possible under all operating conditions without drifting below the smoke point.

Excess-air trim systems

Nearly all trim systems operate as feedback-control loops, sensing stack-gas conditions and trimming the combustion-control system's air/fuel ratio to maintain a predetermined setpoint. Control is complicated by boiler dead time and probe response time, which cause a time delay between actual and sensed variations in the furnace's air/fuel ratio.

Stack-gas analyzers also have a response-time lag, which can be as large as one to two seconds for in-situ probes, to 10 seconds or more for diffusion probes, probes with flame arrestors, or sampling systems. Combined dead time and response time may result in delays of two to 10 seconds at high load, to a minute or more at low loads. For this reason, excess-air trim-control loops must be slow in responding so that they match the stack-sampling system, or else the entire system will have a tendency to oscillate about the setpoint.

Ordinary controllers cannot adjust their speed of response to boiler load conditions. They must be set up with a very slow response to match the long dead times at lower loads. The result is that ordinary trim controllers can correct only for relatively slow-changing variables or system disturbances, and cannot keep up with fast-process disturbances such as rapid load swings.

For example, hysteresis, errors in the damper to valve-stem position, and flexing in linkages can result in unacceptable excursions of excess air. Since the trim controller would not detect this change for a period from several seconds to a minute or more, the potential for off-setpoint firing is likely—particularly where the setpoint is near the smoke point. Because of these and other complexities, ordinary trim systems can wander, even during the smallest load changes.

To reduce undesired excursions into fuel-rich conditions, the excess-air cushion may be increased, but this defeats the original purpose of a trim system. In general, all simple feedback trim controls require some amount of cushion, depending on the accuracy and repeatability of the existing control system.

Newer trim systems account for these problems by using a variety of unique control techniques to interface with the control system and reduce the excess-air cushion. They are designed to handle transient effects, and their adaptive features compensate for system errors and probe response problems. In effect, lead/lag concepts are used without metering elements. The design and operation of these units complement the capabilities and operating deficiencies of any combustion-control system.

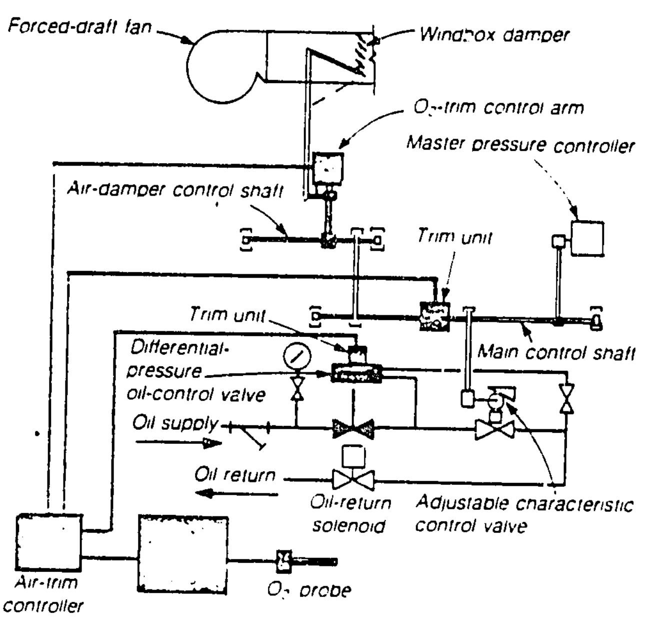
Microprocessor-based control equipment is ideally suited to the new control concepts needed for trim control. A complete understanding of how the trim-control system interacts with final control elements and control hardware is required to match the two systems correctly. No one trim system can be singled out as the best without considering how it will interface and operate with the combustion-control equipment.

Interfacing trim and control

Before installation of a trim system on a packaged boiler, the following two problems common to control systems must be resolved:

■ **Errors or hysteresis** in the way air/fuel is controlled. This includes a careful look at mechanical hardware as well as controls. Overall residual errors should be accounted for in the trim system to minimize excess-air requirements.

■ **Trim-system biasing** technique. Careful consideration must be given to how the trim system matches air and fuel. The trim method should always produce an equal-percentage change (sometimes called ratio trim) over the load range, in order to avoid gross air/fuel-ratio errors during load changes.



4. Typical single-point-positioning combustion-control system trims on either air damper, control shaft, or fuel valve

To gain a better insight into what is required from the combustion-control system, it is important to examine the three typical combustion-control systems used for single-burner boilers: metering, parallel positioning, and single-point positioning. Metering combustion controls are most often considered the optimum system because they actually measure instead of infer fuel and air flow. Unfortunately, the lead/lag technique used in most metering systems upsets trim systems if unaccounted for in the trim-system logic. A simple feedback trim system will even attempt to remove the lead/lag effect, leading to off-setpoint firing during load changes.

Metering systems must be made repeatable and accurate to properly interface with trim controls. Install only the most accurate fuel- and air-flow measuring equipment. Achieving equal-percentage trim is relatively easy, provided all flow signals are linear.

Parallel-positioning control systems use separate power units to drive fuel valve and air damper. Specially cut cams on the power units change air/fuel ratio to match a particular firing rate. Equal-percentage trim is difficult because, to obtain a linear load signal, the two positioner cams must be very accurately cut and matched over the load range.

In single-point positioning, fuel valve and air damper are mechanically linked and operated by a single power unit in response to load demand. Air/fuel ratios are set at startup by adjusting a variable cam arrangement on the fuel control valve. Damper linkage is adjusted to yield as close to a linear change in air flow over the firing range as possible.

Of all the combustion-control systems available, single-point positioning has proved to be the most difficult to achieve equal-percentage trim. This is because there exists no linear signal or linear motion that is representative of load or air flow that can be used to apply an equal-percentage correction. To date, the only accurate method of generating a direct-acting equal-percentage air/fuel correction is trim applied to the fuel train (Fig 4).

Accuracy and repeatability are also problems that must and can be overcome with single-point positioning systems. It has been shown that air/fuel-ratio repeatability of approximately ±2% excess air can be realized by design modifications made to single-point positioning systems.

Testing your burner

In order to develop baseline data for comparing various trim-system options, the first step is an evaluation of existing control-system equipment. You will need O_2 and CO analyzers, stack-temperature indicator, and some means of changing air flow independently of fuel. The last requirement could be difficult for single-point positioning systems and may require the presence of service personnel from the burner manufacturer. Some equipment manufacturers can perform this evaluation for you.

Test the burners first. For each fuel, place the master controller in manual to maintain a constant firing rate. Begin at one end of the firing range and change the rate by increments of 10%, performing the following tests at each step:

■ Record O_2 and CO levels, and stack temperature for normal control settings. You may also want to record radiant-section outlet temperature.

■ Manually reduce air flow while monitoring O_2 and CO levels.

■ When CO increases to barely acceptable levels (100-300 ppm), record O_2 and CO readings and stack temperature. Caution: When firing oil, smoking may occur before reaching high CO. If it does, record the O_2 level at this point.

If the boiler has a negative-pressure furnace, you will need to determine the amount of air infiltration. Use a water-cooled probe to draw an air sample directly from the flame. This will verify actual O_2 level which can be compared with the O_2 level in the stack.

From the above data it is possible to develop an excess-air curve for the existing burner to aid in determining the economics of LEA conversion. The difference between the burner-characteristic curve and normal control settings is the excess-air cushion.

Evaluating existing controls

Probably the best test of your existing control system is continuous day-to-day monitoring of CO, O_2, and opacity, if firing oil. Boiler operators are often a good source of information, and startup data may also be of help. If recordings cannot be taken, then use the following procedure to determine static and dynamic errors in air/fuel ratio:

■ Place excess-air trim in automatic.

■ With load constant, record the steady-state levels of O_2 and CO.

■ Manually increase the load 10% above that in step 2. Record the steady-state O_2 and CO.

■ Very slowly bring the load back to that of step 2. Record maximum, minimum, and steady-state levels of O_2 and CO.

■ Reduce load 10% below that in steps 2 and 4. Record steady-state levels of O_2 and CO.

■ Slowly increase load back to that of step 4. Again, record maximum, minimum, and steady-state O_2 and CO.

■ Repeat entire test for several load points beginning at step 2.

There will be a difference in the steady-state O_2 levels at each load point, depending on whether this point is approached from a lower or higher load. This indicates the amount of hysteresis in the combustion-control system and can be used as an indication of the minimum excess-air cushion required.

The minimum and maximum O_2 and CO levels indicate dynamic errors in the controls and transient conditions in the boiler which must be compensated for by an intelligent trim system with lead/lag-type control. Otherwise, the excess-air cushion must be increased.

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If an excess-air trim system is already installed, it can be evaluated using the following procedure:

- Place excess-air trim in automatic and allow it to reach steady state at constant load.
- Increase and decrease load and record maximum, minimum, and steady-state O_2 and CO as in the combustion-control procedure above. Do this for eight to 10 load points. Compare the steady-state cushion data obtained during the burner test with the data obtained above.

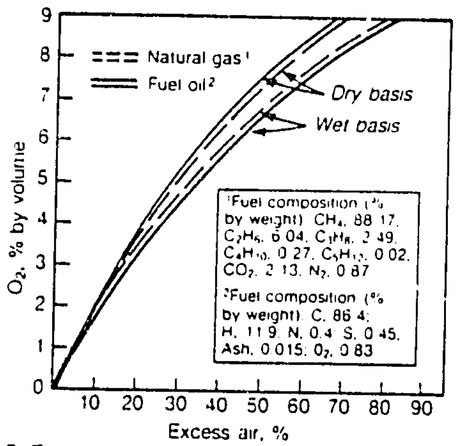
If a chart of actual operating parameters is available (O_2, CO, opacity), it can be used to estimate existing control-system capability. Observe not only the excess-air cushion above burner capability, but also dips and spikes that indicate repeatability problems. The worst-case dips and spikes determine the minimum cushion required for your existing system. It may be possible to improve your control system, but remember that repeatability problems are often caused by mechanical parts such as dampers, actuators, linkages, and valves. In many cases, it is more economical to replace existing controls, particularly for older equipment.

If chart data are not available, the excess-air cushion can be estimated from test data mentioned earlier. Plot steady-state O_2 levels as a function of load. If your system has hysteresis, plot a band of O_2 rather than a line. Between each steady-state data point, add to the line or band the maximum excess-air excursions obtained during combustion-control-system tests. This net band can be used to estimate your existing excess-air-cushion requirements. If your current control system includes excess-air trim, cushion requirements may be larger, depending on the relative sophistication of the system. If the data show excursions into the fuel-rich conditions, the cushion should be increased further.

Determining potential savings

Based on boiler and control-system data, various options for efficiency improvement can be evaluated. Options include burner tuning, control-system tuning, burner replacement, control-system replacement, and excess-air trim.

To establish a baseline efficiency figure for comparison, first determine your average excess-O_2 level and stack temperature over an appropriate load range. Use Fig 5 to determine excess air, then use Fig 2 or 3 to determine stack loss. Boiler efficiency can be approximated by adding 2% to stack loss and subtracting this from 100%. (The exact value is not important because we will be comparing differences.) Then use your average yearly load plus fuel cost to determine yearly fuel cost.



5. For excess air, intersect oil or gas curve from O_2 on abscissa and read down

Now choose an option for improvement, and determine a target excess-air level. If the target level is based on actual burner test data, then use actual stack temperature for the reduced O_2 level in the test, but if the target level is based on a new LEA burner, then the expected excess-air level will be lower than that in the burner test. Use Fig 1 to determine an approximate stack-temperature reduction.

In a similar procedure, find the stack heat loss for this particular option. The difference in stack loss can be used to approximate the net efficiency gain. Figs 1, 2, and 3 are generic and apply to packaged boilers with no air infiltration. The boiler manufacturer should be consulted, however, for a more accurate efficiency estimate. If the boiler has a superheater, consult the manufacturer to determine the effect on final superheat temperature. Do the same for air-heater and economizer manufacturer to determine the effects of reduced mass flow on heat recovery.

One word of caution: For accuracy, you should not assume the expected setpoint to be your target excess-air level if you are adding an intelligent lead/lag trim system. Excess air that is added during load changes will push the O_2 average somewhat above the expected setpoint; how far above is dependent on the frequency of load changes and amount of excess air required. As a rough estimate, add 0.5% excess air for infrequent load changes (one every 15 minutes) and 3% excess air for continuous load changes.

Evaluating burners

If your existing burner cannot operate below 1% excess O_2, consider replacement. The O_2 and CO data taken at different load points during burner tests can be used to evaluate the limitations of an existing burner. Stack temperature and/or radiant-section outlet temperature will help you determine the ability of your burner's flame characteristics to fire at low excess air. In many cases, burner performance may be improved by having it tuned by a service engineer. Replacement of worn or corroded atomizer or gas-burner parts could result in significant excess-air reductions. This option should be investigated before considering a new burner.

One of the prime considerations in evaluating LEA burners is the guaranteed excess-air curve, which will determine potential fuel savings. Also consider that some burners require increased atomizing steam or air consumption, which detracts from fuel savings.

Evaluating O_2 trim systems

Even the best LEA burner is useless if the excess-air trim system is unable to control near setpoint. Of course, most trim systems work reasonably well at constant load. It is during load changes that the worth of a system is really tested. Evaluation is difficult, but could be one of the more important decisions you will ever make on the job. Here are a few pointers:

- Trim systems based on O_2 measurement should include an O_2-setpoint function generator. Be sure the function generator can accurately match the combustion-control air/fuel ratio over the load range for each fuel fired.
- Flue-gas analyzers have been known to fail on occasion. Be sure to identify if and how the system detects failures.
- Control-system failures also occur. Do fail-safe limits exist to ensure flame stability in the case of total failure?
- Trim systems designed for minimum excess-air need advanced lead/lag-type control action. Be sure this action has logic to prevent windup of excess air during extended load swings.
- For automatic operation, trim systems should interface with the flame safeguard system during stages of start-up and shutdown.
- Find out exactly how the trim system interfaces with the control system and what combustion-control modifications will be required.
- Find out if the supplier guarantees a minimum control cushion above the guaranteed burner capability.

What stack-gas parameter you decide to use as a feedback signal to a trim system is an important decision, but this isn't nearly as important as how the control system processes the feedback signal. Both O_2 and CO levels are valuable indicators of flame condition, and neither can claim to be best. Economic considerations and control-system design determine the benefits of using one over the other or both. The most efficient arrangement would be the use of both, but until the cost of CO analyzers comes down, they will only be used on larger boilers.

Edited by Paul Baur

SESSION 12: FURNACES AND KILNS

INTRODUCTION

The purpose of this session is to introduce various types of furnaces and kilns and present methods and modifications to improve their energy performance. Kilns are a type of furnace primarily used by the ceramic industry. As such, furnaces will be reviewed in detail and brief mention will be made of kilns. Specific examples of furnaces and kilns used in industry will be presented, together with factors that affect their operation. The session focuses predominantly upon furnaces and kilns that use fossil fuels as their heat source. Housekeeping measures used to optimize furnace and kiln operation are presented, together with examples of energy conservation measures and technology improvements.

FURNACES

Furnaces are equipment used for process heating of manufactured articles. Almost all manufactured goods are subject to process heating at some stage of their manufacture, so the types and range of furnaces available are extensive. Similarly, conditions and efficiencies at which furnaces operate vary with the duty performed.

It would be impossible to cover all types of furnaces that are used in industry. Hence, only the more common types of furnace will be presented. Furnaces basically comprise a brick-lined chamber that holds or conveys the material to be heat treated. In the chamber, heat is applied to achieve desired final results.

Furnaces can be classified by (see Exhibit 12.1):

- Fuel used
- Method of heat application
- Material handling techniques.

Exhibit 12.1

FURNACE CLASSIFICATION

- Fuel Used
  - liquid
  - solid
  - gas
  - electricity

- Method of Heat Application
  - direct fired
  - indirect fired

- Material Handling Techniques
  - batch
    - bogie (car)
    - cover or bell
  - continuous
    - pusher
    - rollover
    - walking beam
    - roller hearth
    - conveyor
    - continuous bogie
    - rotary retort
    - rotary hearth

Fuel Used

In a fossil fuel-fired furnace, heat is produced by the combustion of a fuel and is then transferred by a combination of three modes of heat transfer: radiation, convection, and conduction. In this session, no attempt is made to distinguish between the three major fossil fuels (oil, solid fuel, or gas), as the net result from their combustion is essentially the same (see Session 2). In practice, furnaces are often operated with fuel substitution capabilities.

Method of Heat Application

The way in which heat is applied to the material (or stock, as it is called) to be heated can be defined as either direct firing or indirect firing.

Direct-fired furnaces are the simplest type of furnace. In the direct-fired furnace, the products of combustion come into direct contact with the stock. These furnaces have various configurations; burners are mounted on sides, ends, or sometimes the roof of the furnace. The products of combustion, or flue gases, are exhausted through flues in the roof sidewalls or the hearth of the furnace.

Low-temperature furnaces (those operating at or below 900°C) do not often have a uniform temperature profile, owing to the relatively large temperature difference between the furnace and flame temperatures. High quantities of excess air are used to reduce the flame temperatures to those required and to improve uniformity of the temperature profile. Care must be taken, however, because excess air can promote excessive oxidation and scaling of the stock.

Direct-fired furnaces are modified using baffles and walls to reduce the risk of flame impingement. Examples of these types of furnaces are the underfired, overfired, and sidefired furnaces.

In the **underfired furnace,** the flame is located under the hearth of the furnace, and hot products of combustion rise upward through the hearth to heat the stock. Flues are usually located in the roof.

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The temperature below the hearth is high, but the actual furnace temperature can be controlled by use of excess air. Underfired furnaces offer some advantages over the simple direct-fired furnace. Stock is protected from direct flame contact, and excessive scaling is prevented by ensuring complete combustion before the flue gases enter the heating chamber.

Disadvantages include increased fuel consumption per unit of stock heated because the furnace is larger than practically required and because heating times are increased. In addition, because both sides of the hearth are exposed to heat, hearth life is usually shorter, and the load-bearing capacity of the hearth is reduced.

In the overfired furnace, the combustion chamber is located above the furnace. Hot flue gases enter the heating chamber through a perforated arch in the roof of the furnace, discharging through ports at hearth level. Operating characteristics are similar to the underfired furnace, but this design is more efficient because of better furnace aerodynamics, which improve heat transfer rates.

In the side-fired furnace, combustion chambers are located on one or both sides of the heating chamber. A bridge wall separates the combustion and the heating chambers. The bridge wall promotes turbulence, thus ensuring good combustion as well as protecting the stock from flame impingement. Fuel consumption rates are similar to simple direct-fired furnaces.

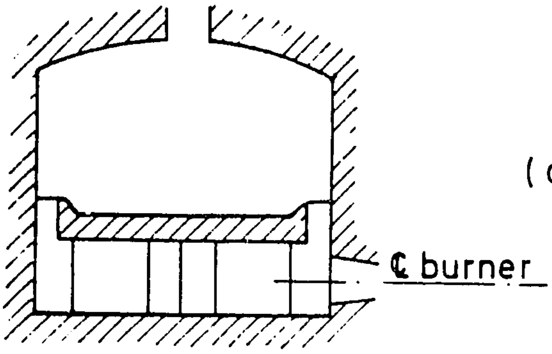
Examples of direct-fired furnaces are shown in Exhibit 12.2.

Indirect-fired furnaces are used whenever contact between flue gases and the stock could potentially cause damage to the stock. There are two basic types of indirect heating furnaces: the muffle furnace and the immersion-type furnace.

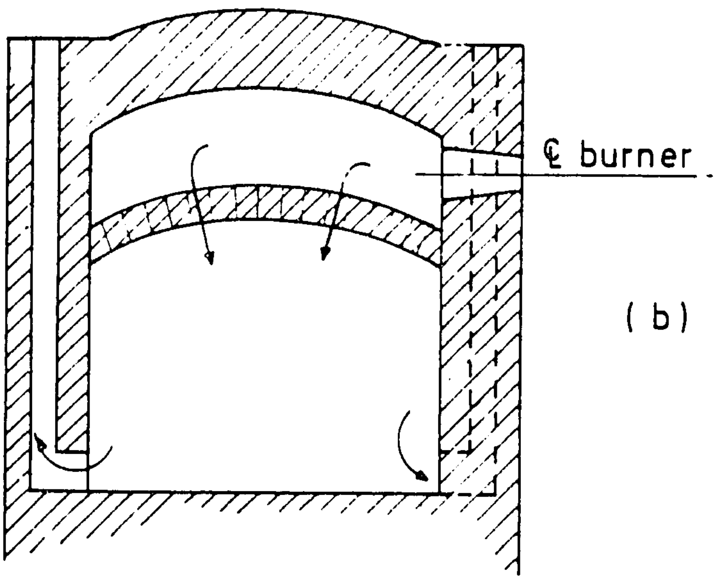
In the muffle furnace, the stock or the combustion products are muffled by use of radiant tubes; or, alternately, the stock is placed in a refractory or metallic muffle and direct heat is applied to the outside of the furnace (see Exhibit 12.3). Material selected as the muffle has a large influence on fuel consumption because its thermal conductivity will affect the rate of heat transfer from the heat to the stock. Care also must be taken to select materials that have relatively long lives.

Exhibit 12.2

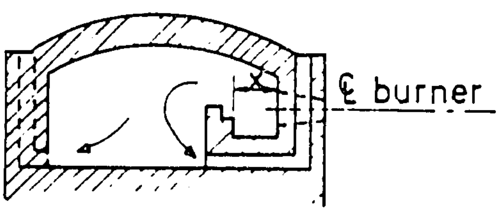
Types of Direct-Fired Furnaces



(a) Under-fired type



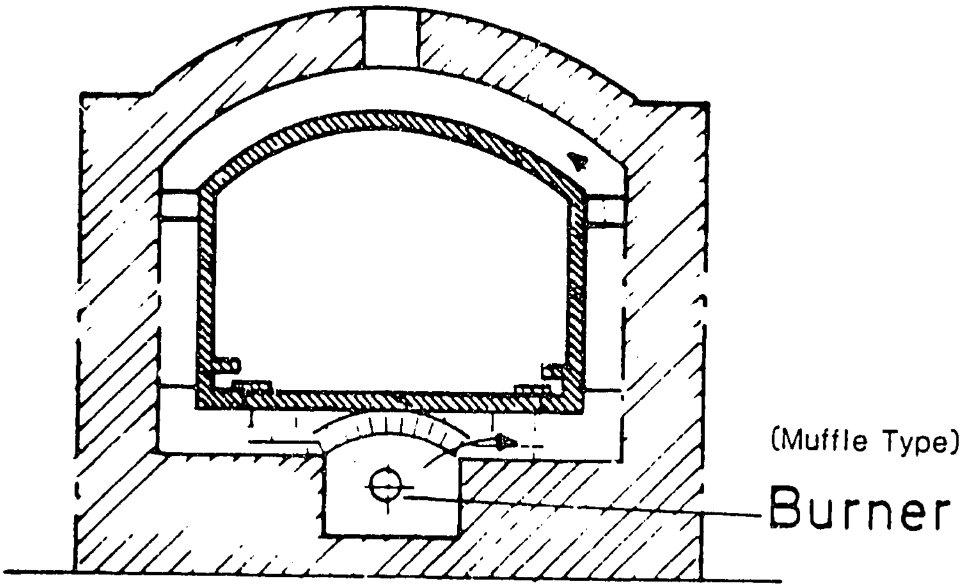
(b) Over-fired type



(c) Side-fired type

Exhibit 12.3

MUFFLE FURNACE (INDIRECT-FIRED)



Immersion-type furnaces are indirect-fired furnaces because the stock is placed inside a bath of salt or metal. The salt or metal bath is heated in a pot, and so neither the immersion bath nor the stock come into contact with the products of combustion. Heating rates are fairly uniform in this type of furnace. Depending on the liquid heating material, the rating of these furnaces can be high.

Material Handling Techniques

There are two broad classifications used to describe how stock is handled inside the furnace during the heating process:

- Batch type
- Continuous.

In **batch furnaces,** stock is charged either by hand or by a simple machine with arms. The stock position is fixed during heating and subsequent heat treatment period. On completion of the heat treatment, the stock is removed.

There are many variations of the batch types of furnace. Rather than attempt to cover them all in this session, three of the more common ones are presented:

- Bogie (car) type
- Cover or bell type
- Melting furnace.

Bogie (car) furnaces consist of a bogie generally running on rails that is loaded and unloaded outside the furnace,. After loading, the car is pushed into the furnace, where the bed of the car forms the hearth of the furnace. A furnace door is provided together with a series of sand seals to prevent air infiltration or gas leakage from the furnace, as well as providing protection for the bogie haulage gear from the heat. These furnaces are not designed for underfiring.

Bogie furnaces are direct-fired, with occasional use of side firing. Flues are located in the side walls at hearth level. Bogie furnaces are used predominantly for heating bulky, heavy objects such as large castings or pressure vessels.

Cover- or bell-type furnaces are a form of muffle furnace. They are made up of a fixed refractory base with a removable metal case or inner cover and a removable refractory-lined heating cover or bell. The burner forms an integral part of the bell.

The stock is placed upon the refractory base and covered. The inner cover has a series of seals to provide a protective atmosphere to the stock (see Exhibit 12.4). These furnaces are used primarily for annealing strip coils in a controlled atmosphere.

Melting furnaces are used to prepare materials in a liquid state for subsequent processing. The most common types are found in the glass industry, and the following discussion is limited to them.

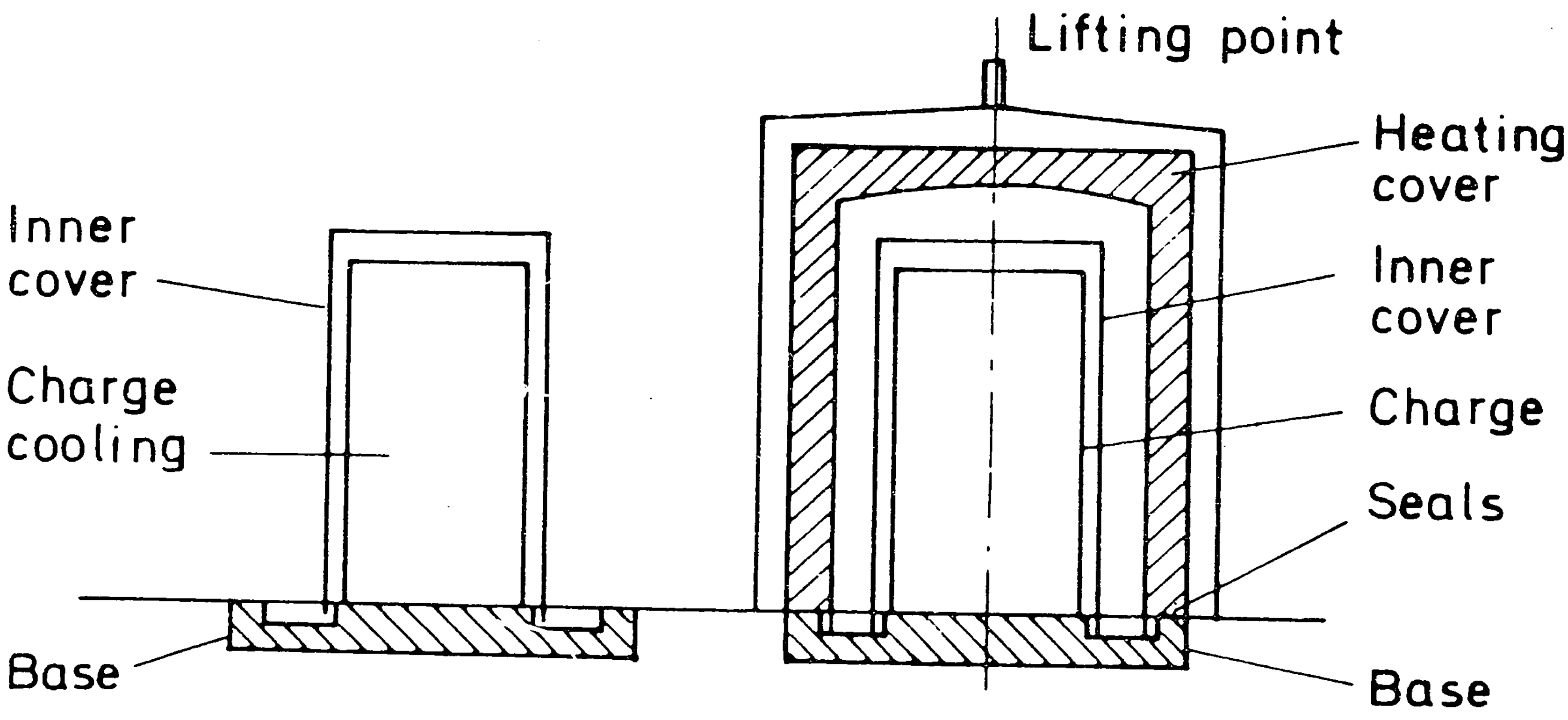
Glass melting is essentially a three-stage operation. The first stage is fusion or melting in which precise amounts of sand, soda ash, limestone, and various components become fluid and also go through some chemical reactions, including liberation of gaseous components such as carbon dioxide, sulfur dioxide, formation of silicates, and mixing of the liquid components. The second stage is a refining step in which high temperatures are maintained. Essentially, gas bubbles are dispelled by buoyancy from the glass. The third stage is a cooling step to increase the viscosity of the liquid glass.

Two general types of melting furnaces are used:

- Pot furnaces
- Tank furnaces.

Pot furnaces are not as common as tank furnaces. They are used predominantly when a wide variety of glasses are produced in small quantities. The charge is loaded into a pot and kept there during the three-stage cycle. Pot furnaces are hand-made from pot clay and have capacities of between 100-1,500 kg of glass. The pot is placed in a furnace comprising a combustion chamber with anarcheal roof built of high-grade

Exhibit 12.4



CROSS SECTION

Cover-Type Furnace

refractory. Pots can either be covered or left open. Heat recovery devices such as recuperators and regenerators are often used to improve fuel consumption.

Used for very small production rates, pot furnaces have some disadvantages. Fuel consumption is relatively high as melting takes place first at the outer walls of the pot and proceeds gradually towards the center, resulting in extended cycle times, and heat supplied during melting and refining is lost during cold storing. The extreme temperature changes also affect the pot material, and pot breakage can occur frequently with subsequent loss of production.

Tank furnaces are essentially rectangular in shape and consist of a hearth melting unit containing a refractory bath in which the melt is placed, and a combustion chamber located above the bath. Heat is supplied from flames directly above the bath. Materials are charged continuously or at short intervals at one end and are discharged at the other end following the three stages of operation. Although the furnace is an integral unit, it is subdivided into zones, which helps to control the three operational stages.

The melting tank consists of a rectangular bath divided into two separate tanks of unequal size. Separation is done by a double wall built at right angles to the length of the furnace. The double wall is bridged by refractory blocks. Both baths are covered by one continuous crown. One tank is used for charging, the other for working. They are connected by a channel or throat in the double wall through which glass flows.

Tank furnaces are either end-fired (along the furnace length) or cross-fired, and many fuels are used. Heat recovery equipment, such as recuperators or regenerators, are incorporated into the furnace construction.

Continuous furnaces are used when the furnace forms an integral part of the production line and stock is needed at frequent and regular intervals. As opposed to the batch furnace, the stock moves as it is heated. The methods of moving the stock vary with duty, size, and shape of material that is being treated.

Continuous furnaces include:

- Pusher
- Rollover
- Walking beam
- Roller hearth
- Conveyor
- Continuous bogie
- Rotary retort
- Rotary hearth.

The above are described briefly in the following paragraphs.

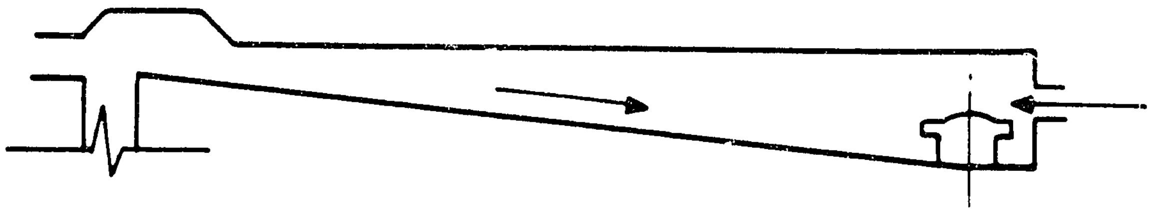
In the <u>pusher furnace</u>, the stock is pushed through the furnace directly or in trays. The furnace is usually designed with a sloping hearth that reduces the pushing effort. These types of furnaces are direct-fired.

Care must be taken when selecting these furnaces, because stock that has rounded edges or a crooked shape has a tendency to pile upon one another. This is overcome by reducing furnace length and by shaping skids on which the stock travels. The use of a sloping hearth aids this problem, but can create high furnace pressure at the charge end owing to the buoyancy of the combustion products.

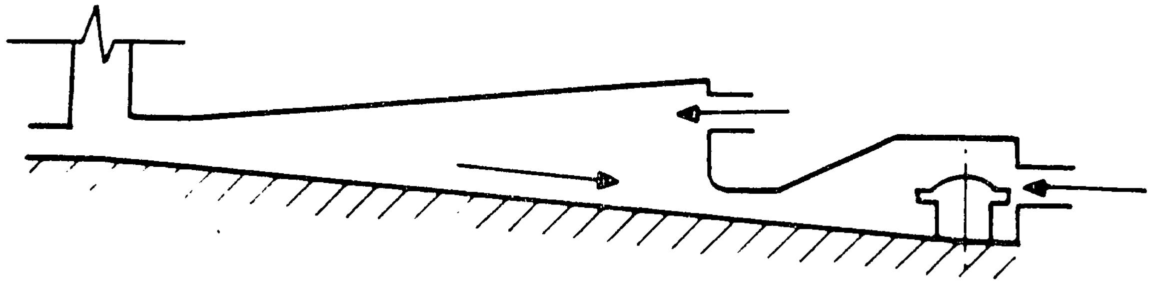
Examples of pusher furnaces are shown in Exhibit 12.5. They are used extensively for reheating steel prior to rolling and are capable of handling throughputs in single-zone furnaces of about 30 tonnes per hour (34 tons per hour) of 100-mm (4-inch) stock and up to 250 tonnes per hour (284 tons per hour) of 300-mm (12-inch) material in five-zone furnaces.

<u>Rollover furnaces</u> consist of an inclined hearth down which the stock rolls by gravity. The hearth is flattened at the discharge end to prevent stock rolling completely out of the furnace. These furnaces are limited in application, owing to the temperature limit at which the stock softens and hence cannot roll. If the stock cannot roll, the furnace operator is required to rake the stock out of the furnace. They are used predominantly for heating steel billets at temperatures up to 800°C-850°C.

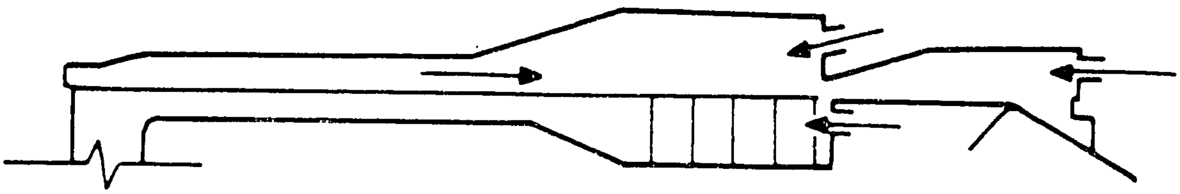
Exhibit 12.5



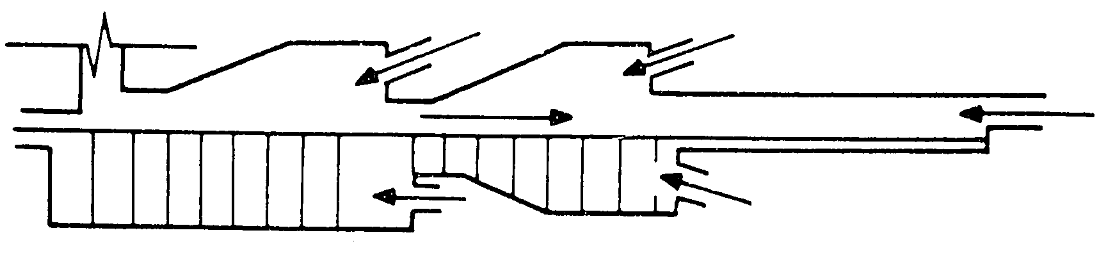
a Single zone



b Two zone



c Three zone



d Five zone

Pusher-type furnaces

Walking beam furnaces consist of a series of alternately arranged stationary and movable beams. These form a hearth on which the stock is placed. The stock essentially rests upon the stationary beams and is passed through the furnace by the action of the movable beams.

In general, the moving beam operates on a cycle of up, where it contacts and lifts the stock; forward, where it moves the stock; down, where it redeposits stock on the stationary beams; and back to its original position so the cycle can be repeated. An example of a walking beam furnace is shown in Exhibit 12.6.

Walking beams are usually direct-fired, occasionally side-fired. The stock is spaced apart to prevent pile-up, which also permits heating to take place on three or four sides, depending on the firing pattern. Increased exposure to heat results in faster and more uniform heating patterns.

Walking beams are constructed from refractory materials, and until 1965 were top-fired only. However, they are now available with tubular water cooling beams, which makes top and bottom firing feasible.

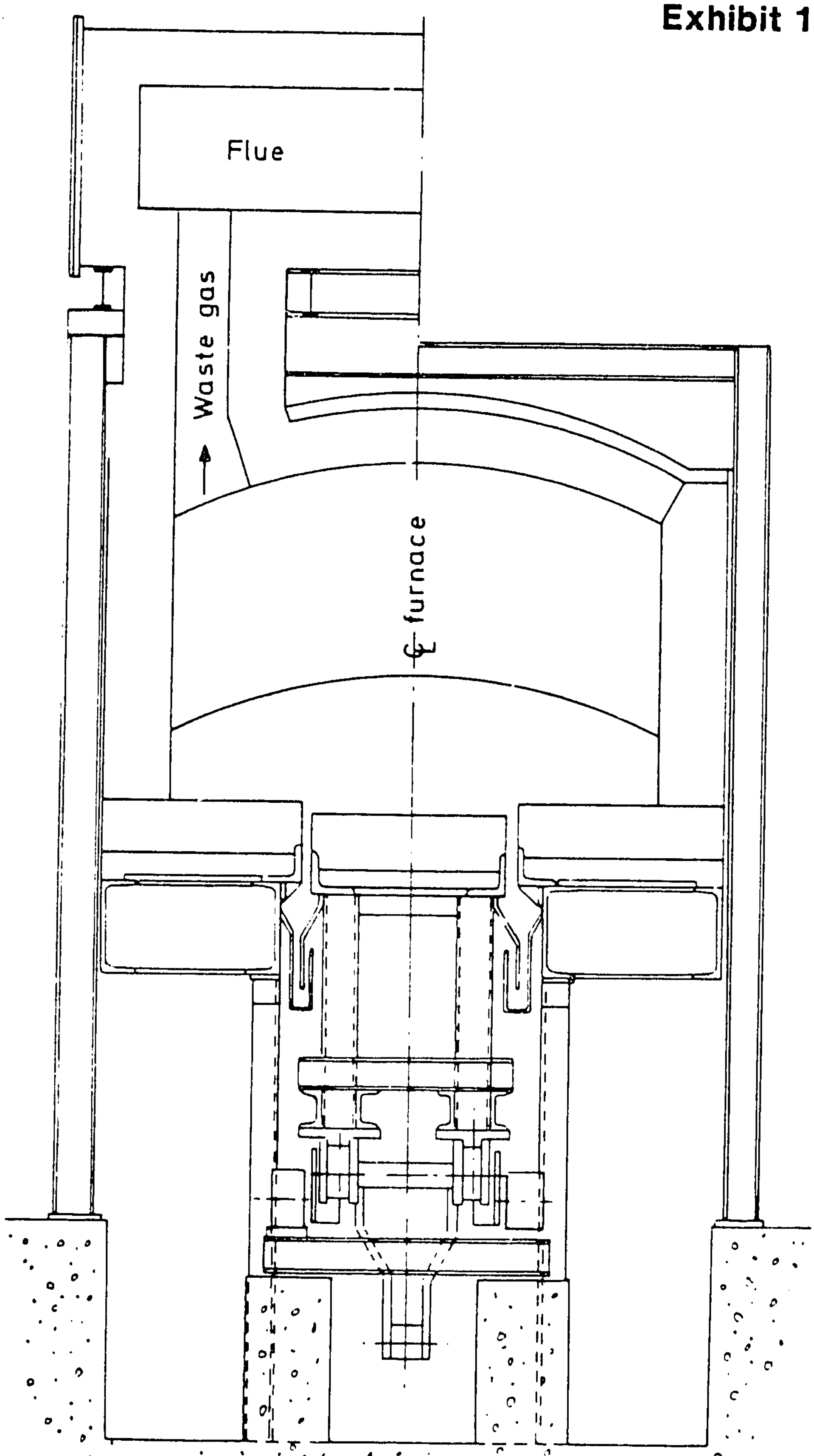
They are used to heat both ferrous and nonferrous materials, and can be arranged with several heating zones. Because of their advantages over the pusher type, they are the most common type of continuous furnace.

Roller hearth furnaces use a series of closely spaced rotating rollers to send the stock through the furnace. They are usually direct-fired or radiant tube-fired and operate up to 1,000^{o}C.

Conveyor-type furnaces use a continuous chain to move the stock through the furnace. The chain travels in slots in the hearth of the furnace. Limitations are posed by the temperature to which the chain material can be subjected.

Continuous bogie furnaces consist essentially of a series of bogies that travel through the furnace. The stock is placed onto a bogie outside the furnace as in batch operation. The bogie is then pushed into the furnace through the front end door, each bogie thereby moving through the furnace in succession. The bogie is removed from the

Exhibit 12.6



Walking-hearth furnace

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furnace when it reaches the other end of the furnace. Stock is then removed, and the empty bogie is returned for reloading and subsequently to the front end of the furnace for recharging.

Care must be taken with the sealing between adjacent bogies in the furnace, or heat losses can be excessive and lead to failure of the wheels and bearings of the bogie.

These furnaces are usually direct-fired either from the side walls or the top of the furnace. Continuous bogie furnaces are used in the metal processing and ceramic industries.

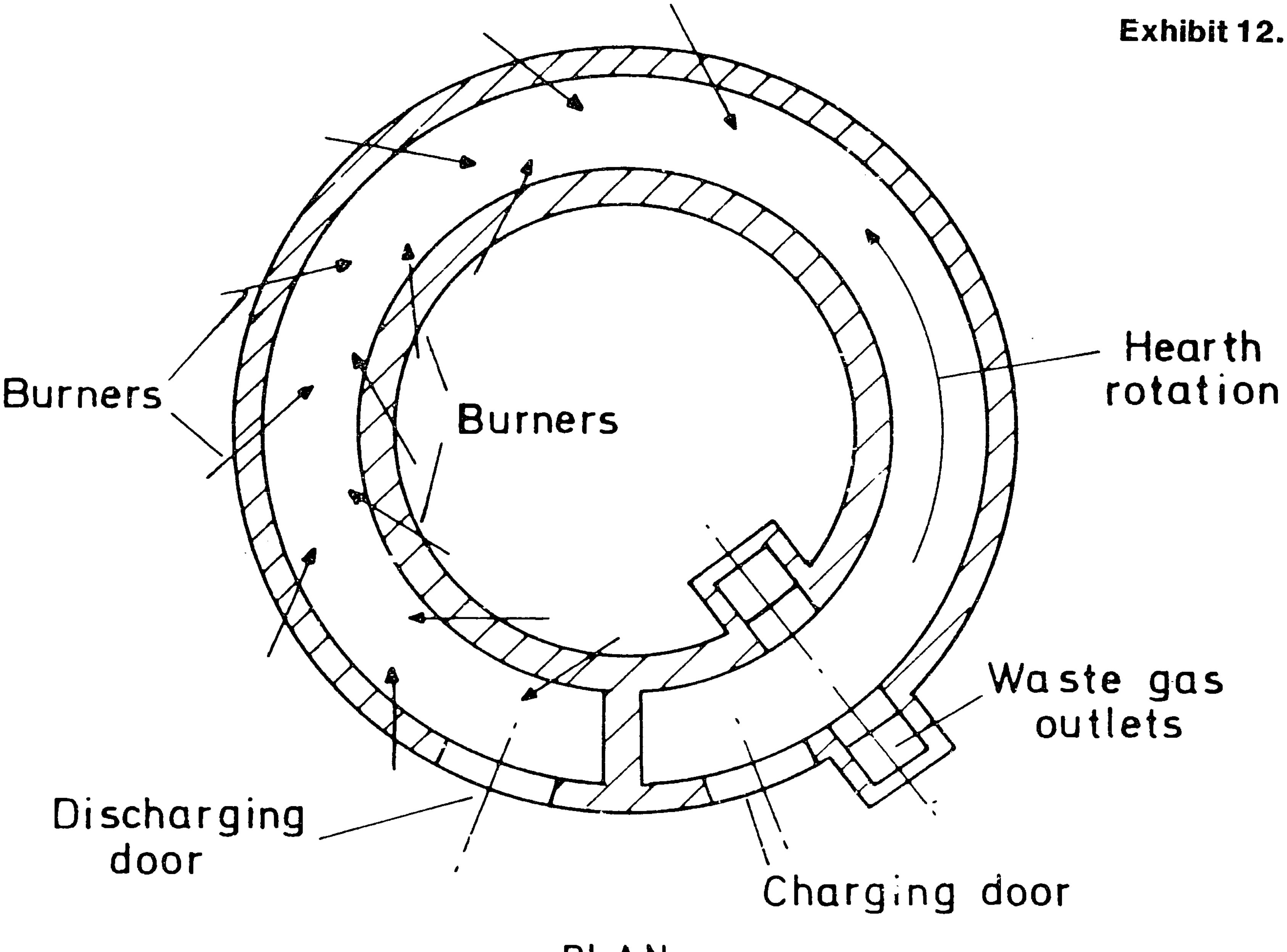
Rotary retort furnaces consist of a horizontal drum of heat-resistant material that contains a screw thread. Heated stock passes through the furnace due to the pitch of the thread helix and the speed of the rotating drum. Stock is fed into the furnace from a hopper and is discharged from the other end. The burner fires into one end of the furnace, thereby providing heat.

In **rotary hearth furnaces,** the stock is placed onto a rotating hearth. Stock passes through one revolution of the hearth, during which time it is subjected to all heating and/or cooling zones that are employed for heat treatment purposes. After one revolution, the treated stock is removed through a discharge door adjacent to the charging door (see Exhibit 12.7). This furnace has the advantage that the same person can charge and discharge the furnace.

The hearth, which is usually constructed of refractory, rotates on wheels and track or ball bearing and is driven through reduction gear by an electric motor. These furnaces are usually direct-fired, with the burners aimed tangentially towards a circle of mean diameter.

Rotating hearths can be constructed in a wide range of sizes, from less than 1 meter (3 feet) to 23 meters (76 feet) mean diameter. They are used to heat a wide range of materials, provided that the stock is kept flat and does not roll about the furnace as the hearth rotates.

Exhibit 12.7



Rotating-hearth furnace

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KILNS

Kilns are basically furnaces used predominantly for heating or firing products made by the ceramic industries. In firing clayware, three stages are involved -- drying, oxidation, and soaking or finishing. In the first stage, moisture is removed by hot air or gases until the ware is dry. The second stage involves the oxidation of carbonaceous matter, and the final stage involves maintaining a uniform heating zone so that the required amount of vitrification takes place. Modern kilns are designed to minimize heat consumption by reusing heat given up during cooling for preheating other fresh stock. With certain ceramics, muffles are provided to prevent stock contamination by the combustion gases. Kiln performance is affected by draft control through the kiln, the setting of stock, and the firing schedule.

Originally, kilns were mainly batch-type, and no attempt was made to recover cooling heat, but increasing fuel costs have led to most kilns now being continuous or semi-continuous type.

Continuous kilns are of two types -- the tunnel kiln, in which the three zones are fixed and the stock moves through the kiln on bogies, or the annular moving hearth type.

A semi-continuous kiln consists of a series of chambers connected by suitable openings. Stock is placed into a particular chamber where it remains for the duration of the three-stage firing cycle. Preheating, heating, and cooling zone conditions are applied in turn to each chamber. Combustion takes place in the hottest chamber heating zone, combustion air being preheated in the preceding chamber. Gases leaving the hottest chamber preheat ware in successive chambers before finally passing to the chimney.

Semi-continuous kilns are known as Hoffman kilns and have compact layouts. Control of firing stages can be difficult because the heat is used to preheat several different batches of material.

The cement kiln is used for calcining lime. Cement kilns can be either of the rotary type or of a vertical type.

Rotary cement kilns are basically a long cylinder supported upon rollers. Their physical dimensions vary considerably, but typically the length to diameter ratio is between 30 and 40 to 1. The rotary cylinder or drum is inclined at an angle (typically 3-5^{o}) and rotates at about 1-2 revolutions per minute. Stock is charged at the elevated end and discharged at the lower end. Combustion takes place at the lower end, so the stock flows in the opposite direction of the combustion gases. Only 10 percent of the space inside the kiln is occupied by the stock.

Rotary kilns operate at temperatures between 1,250^{o} and 1450^{o}C. Hence, longer kilns tend to be of higher thermal efficiency than short kilns. Typical modern rotary cement kilns are fitted with many preheaters, heat exchangers, and coolers and have an energy consumption of about 5.7-6.7 GJ/tonne, which is very high.

HOUSEKEEPING MEASURES

To ensure that furnaces and kilns operate at optimum efficiency, certain housekeeping and maintenance procedures should be followed.

Problems with furnace operation that cause inefficiency result from one of the following areas:

- Design
- Construction
- Operation
- Maintenance.

When establishing a maintenance program for the first time, the energy coordinator should determine the status of furnaces under consideration.

The following checklists are presented to indicate some of the information required to set up a program of planned maintenance.

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Design

The data below are required and should be kept by the energy coordinator as part of the overall energy management data base for an industrial plant. Whenever changes or modifications are made, these should be recorded together with subsequent operational conditions arising from the modification.

- Main furnace

  - What is the plant used for?
  - Was it designed for this use?
  - What fuel is used?
  - Was it designed for this fuel?
  - What type burner is in use?
  - Has the burner been changed since design?
  - What burners were originally installed?
  - At what capacity or working rate is the plant being operated?
  - What was its original rating?
  - How was the original capacity specified, if at all?
  - Is the present rating:

    correct?
    high?
    low?

- Modification

  - Has the plant been modified since installation?
  - If so, how?

    by rebuilding?
    by changing firing?
    by re-rating?
    by change of use?
    by adding or removing heat exchangers or ancillaries?

- Ancillaries

  - Is there any fuel preparation?
  - What does the preparation plant consist of?
  - Is it still used:

    as originally designed?

    effectively?

    ineffectively?

    at all?
  - Are heat exchangers fitted?
  - Where?
  - Are they still in use:

    effectively?

    ineffectively?
  - What stack size is being used?
  - Is this the original stack?
  - Is it still necessary?
  - Was it ever necessary?
  - Are the designs of fittings for inspection parts and doors sound?
  - Can they be improved?
  - Are they in good condition?

Construction

Records are required on the construction of the furnace. Good furnace construction is a fundamental part of furnace operation.

Any change in construction should be recorded and maintained in the overall energy management data base.

- Building

  - Who built the furnace?

    furnace builders

to their own design?

to user's design?

users

to a standard design copy?

to their own design?

- Was the furnace soundly built in the first place?
- Were the refractories and other materials correctly specified?
- Was the most appropriate firing equipment correctly chosen?
- Was the basis for the choice:

  engineering?

  economic?

  a compromise between both?

  chance?
- Was the firing equipment correctly installed?
- Were the necessary auxiliaries (e.g., pipework, furnace, doors, dampers, pulleys, chains, levers):

  correctly installed?

  connected and tested?
- What records exist recording installation checks and tests?

Operation

The most important record and information that should be kept is a monitor of how furnaces are operated. Regular checks on the following items are imperative to identify decline in performance as well as identification of efficiency improvements.

- Conditions

  - What are optimum operating conditions?
  - What is their basis of specification?
  - Are these known and understood:

    by the operators?

    by management?
  - Are they followed?

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- Are there any operating specifications at all?
- What is the air/fuel ratio in current use?
- Is it:
    - fuel-rich?
    - air-rich?
- What is the correct air/fuel ratio?
- What is the basis for choice?
- Is the air/fuel ratio correctly set?
- How much air is necessary, by changing fuel rate:
    - alone?
    - with dampers or air supply?
    - with dampers and air supply?
- When necessary, is furnace temperature changed by closing:
    - air gate on either high pressure gas burners, or burners giving pressurized gas/air mixture?
    - gas and air cocks on individual burners?
    - main manifold cocks?
    - with oil burners?
- Are secondary air slides provided and used on natural draft furnace?
- Are furnace doors, sighting holes, lighting holes, and inspection ports left permanently open?
- Are furnaces with regenerators being operated with permanently open doors?

- Control

    - Are there any automatic control instruments for:
        - air/fuel ratio?
        - temperature?
    - If so, are they still operating?
    - Is furnace correctly instrumented for:
        - fuel consumption?
        - air supply?
        - temperature?
        - exit gas composition?

pressure and draft gauges?

steam meter when necessary?

automatic recording?

- Are automatic controlling instruments being:

  correctly used?

  used at all?

- Are fuel and/or air supplies individual furnaces, or to separate shops, correctly governed?

- Start and stop

  - Are furnaces lit:

    too soon?

    too late and forced?

  - What is the optimum heating rate?
  - Is it known to the operators?
  - Is it known at all?
  - Are furnaces always loaded to capacity?
  - If not, is it the fault of:

    operators?

    management?

    unavoidable?

  - Are furnaces maintained at temperature during standby for:

    meals?

    night?

    plant stoppages?

  - Are furnaces used for undesigned uses such as space heating in cold weather?
  - Are molten steel ladles ever heated:

    too long?

    until they are too hot?

Maintenance

Monitoring and adjusting operating conditions are only part of an overall planned maintenance program. It is necessary for routine inspection and maintenance to be completed so that breakdowns are minimized. The following checklist should be completed once a week for a system that operates continuously. All findings should be reported in writing and appropriate action taken. Records should be maintained and reviewed on a monthly basis to determine whether persistent problems are occurring witn one or more items. This will ensure a timely identification of potentially serious problems.

- Main plant
  - Is the furnace structure and brickwork in good condition?
  - If so, is this:
    good initial construction?
    good maintenance?
  - Are furnace doors and other ports:
    in good physical condition?
    operating as designed, or at all?
    sealing correctly where this is necessary (e.g., sand seals, car bottom furnaces)?
  - Are all gas passages and flues:
    in sound condition?
    clear of collapsed brickwork scale and rubble?

- Ancillaries
  - Are gas and air valves:
    clean?
    dirty and not sealing properly?
  - Are inspirator throats:
    clean?
    choked with oil and dirt?
  - Are burners:
    generally clean?

affected by dirt or deposited carbon?
distorted by overheating?

- Are pumps, motors, fans, etc.:
  being kept cleaned and oiled?
  getting dirty and overheating?
  still working at all?
- Is all thermal insulation:
  still in good initial condition?
  maintained in good condition by repair?
  still in position at all?
  was it ever there?
- Are there any leaks in fuel, air, or steam lines?
- Are regenerators still working?
- If stopped, is this:
  because fan motors out of action due to blown fuses not replaced?
  due to having been flooded by condensate from flue gases?

- Instruments

  - Have instruments been recalibrated recently (see Session 9)?
  - Are instruments regularly checked:
    for zero errors?
    for scale errors?
    for other incorrect operation?

- Repairs

  - If errors affecting operation are discovered, what steps are taken to get them rectified?
  - What checks are made on other operations (e.g., quality control on output from an overheating furnace)?

ENERGY CONSERVATION OPPORTUNITIES

This section of the session summarizes different categories of energy conservation opportunities that exist on furnaces and kilns.

The major improvements that can be made are:

- Excess air control
- Waste heat recovery
- Insulation
- Openings and leaks reduction
- Idle equipment shutdown
- Reduction of losses during recycling
- Continuous efficiency monitoring.

Control Excess Air

The use of excess combustion air can constitute a major energy waste. The use of insufficient air is just as wasteful, but is less common.

Reducing excess air will change the rate at which fuel is fired and result in a higher flame temperature, a more rapid heating of the stock, and an energy-saving shorter cycle. However, it will also increase the flue gas temperature and therefore affect the stack loss.

If, in addition to reducing air flow, the fuel flow is also reduced to maintain the same stack temperature, there will be decreased gas velocity and less turbulence in the furnace, with a corresponding increased hot gas residence time within the combustion chamber. The exact effect of these latter two changes on heat transfer to the stock and to the furnace walls is not always evident or readily estimated.

In spite of these complexities, **excess air control is probably the most important measure in conservation in furnace and kiln operation**. Two methods of controlling excess air are normally used. Both methods involve an analysis of oxygen concentration and temperature in the flue gases. In the simplest method, an audible alarm or signal is triggered by a measurement of oxygen outside a predescribed range, and the furnace operator then makes a manual adjustment to draft conditions to bring the excess air level back to required levels. This method is not particularly sophisticated as it relies on machine and man interface. Typical U.S. installed costs for an oxygen analyzer that can be used for this type of control are $3,500. Energy savings will depend upon the sensitivity of the control settings and the response of the operator to the alarm signals.

Because of obvious deficiencies, a more sophisticated method is often used and involves control systems that respond automatically to the shift in excess air levels outside the control range. The automatic system may control supply and exhaust air dampers, fuel supply and burner operation, furnace temperature, and furnace pressure. Costs for such a system will depend on several factors, including the flue gas analysis required (may include oxygen, carbon dioxide, carbon monoxide to low concentrations, and temperature to plus/minus 1°C), the number of air dampers, burners, and fuel systems that are to be controlled, and requirements for monitoring and reporting furnace operation. Microprocessor-based systems that control excess air as part of an overall process control network are becoming increasingly popular. U.S. costs for these systems can range from $20,000 to more than $1 million, depending on the exact nature of the system and elements of the process controlled. Obviously, excess air level controllers on a stand-alone basis would not cost as much (typically $15,000 to $100,000 and more). Savings from reducing excess air are often significant, as high as 5 to 7 percent of the fuel input. In addition, product quality improvements are often achieved.

Waste Heat Recovery

Waste heat recovery is a major way of recovering useful heat from furnace exhaust. Exhaust temperatures are often high, and there are many ways in which the heat can be reused. Waste heat streams in excess of 814°C can be used to generate steam to perform mechanical work or to generate electricity. Because of the complexities of design of waste heat recovery steam generation units, no costs for their installation are presented here.

Lower-temperature gas streams can be useful and save money in such applications as drying and preheating incoming products (including combustion air), heating water, or process heating. If the stream is only a few degrees above the ambient temperature, it may still contain much energy; however, it may well be impossible to recover it economically.

Typical waste heat devices are shown in Exhibits 12.8-12.10.

The three devices illustrated are not the only types of heat recovery systems that are used by industry. Other waste heat recovery systems are discussed in Session 14. The economic benefits of waste heat recovery for the three devices shown in Exhibits 12.8-12.10 are good. Flue gases from high temperatures usually contain significant amounts of energy (up to 40 percent of fuel input). Recuperators can be used to preheat air; the potential fuel savings from preheating air are shown in Exhibit 12.11. Typical savings are in the 20-25 percent range.

Ceramic recuperators recovering heat from high-temperature exhaust streams are now available but have had only limited use by industry because of their recent development. The cost for this type of unit is high, but heat recovery rates of up to 45 percent have been achieved.

Often, when using recuperators to preheat combustion air, it is necessary to modify burners to allow them to handle high-temperature air, which affects the economics of the heat recovery system, but typical simple paybacks for those systems are between 1 and 3 years. Exact cost details are impossible to predict, but for a continuous furnace operating with a fuel input of 20 GJ per hour and exhausting about 30 percent of this fuel input, the recuperator and burner modifications would cost about $200,000 in the United States. Energy savings would give a simple payback of about 2 years.

With lower temperature heat streams, air-to-air heat exchangers can be used to direct the heat back into the process. Costs for a unit installed to preheat 550 m^3 (19,400 ft^3) of air through a 15°C temperature differential is estimated at $40,000. Fuel savings for this unit would produce payback periods of just over 2 years.

Exhibit 12.8

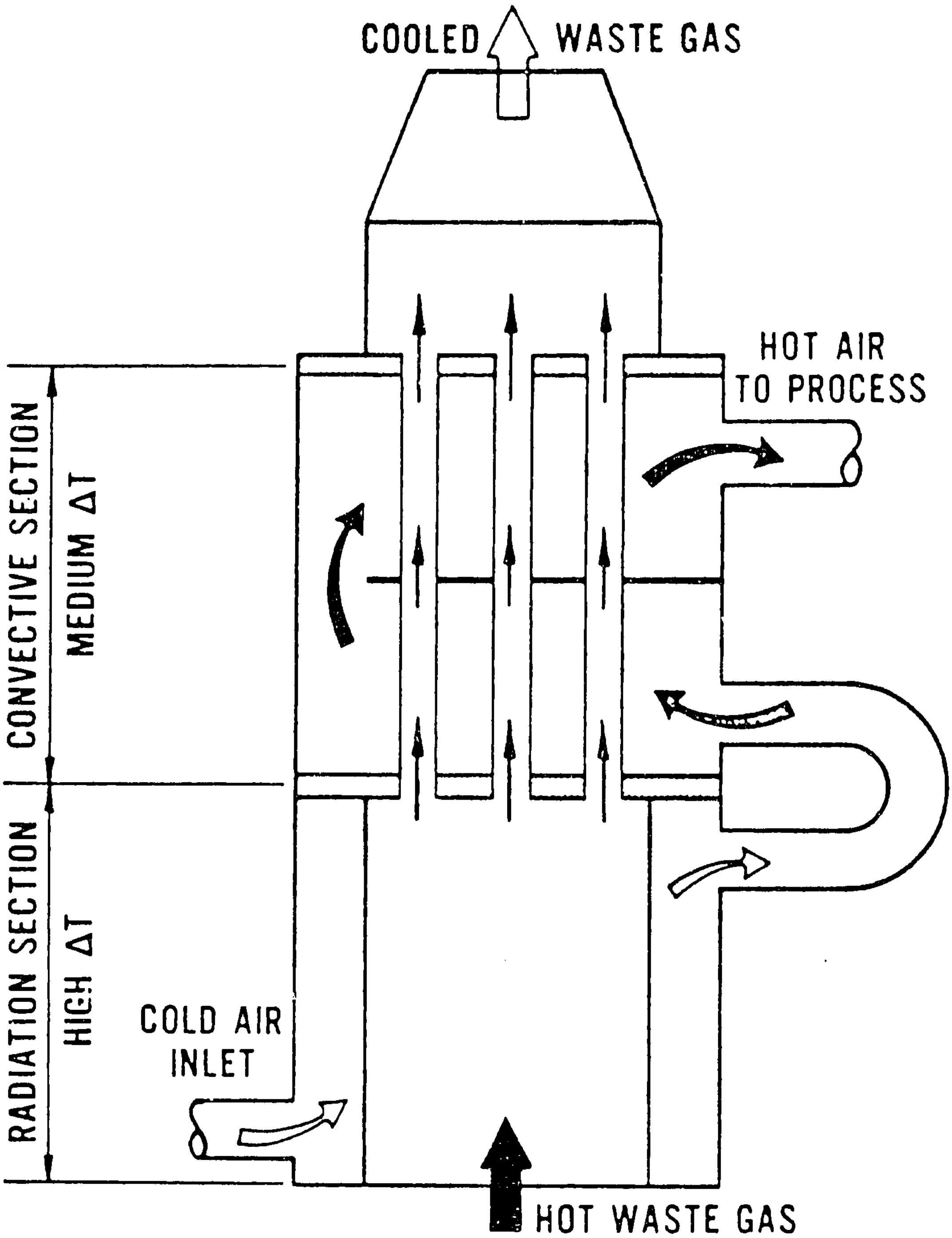


Diagram of combined radiation- and convective-type recuperator.

Exhibit 12.9

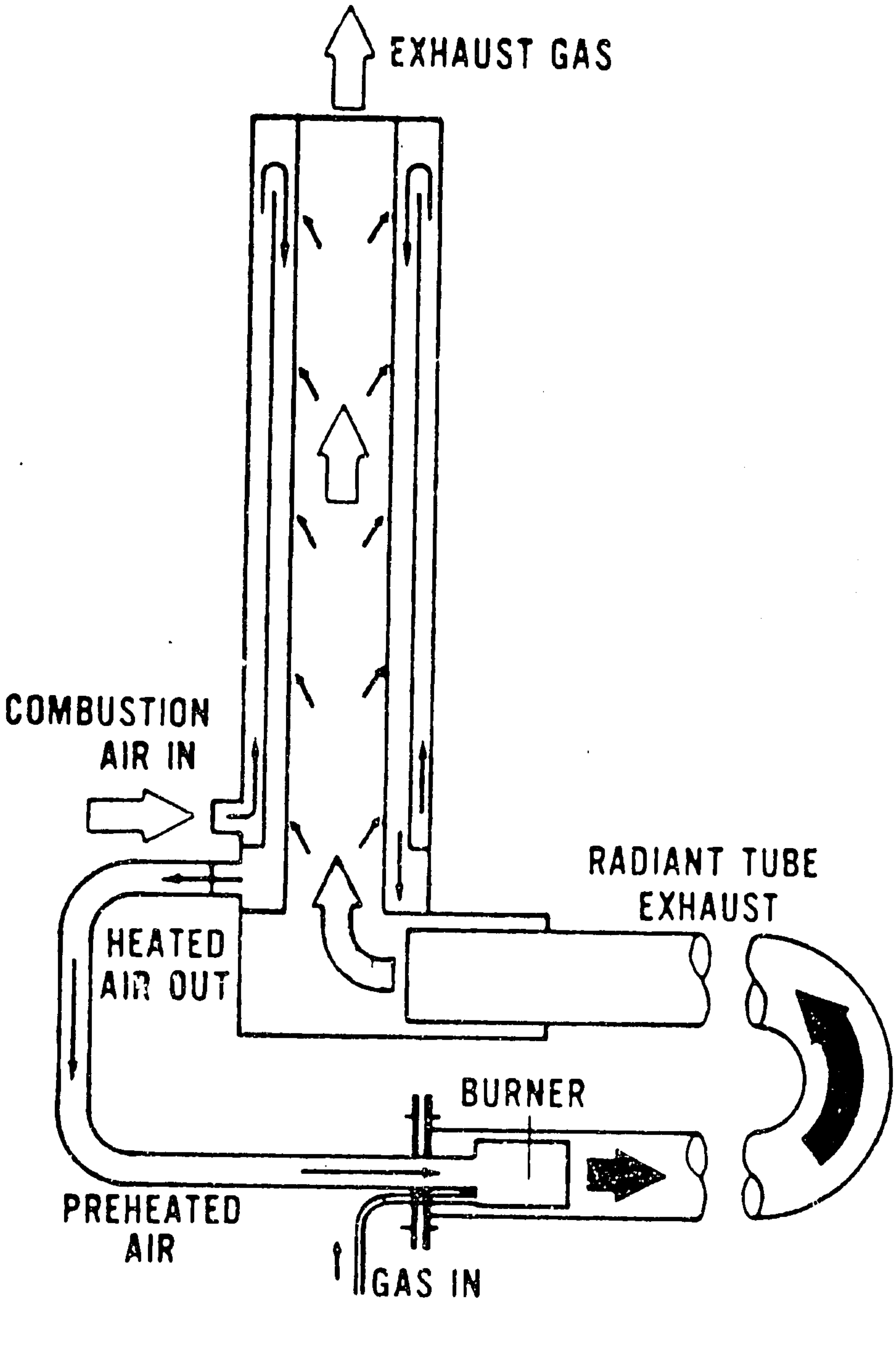


Diagram of a small radiation-type recuperator fitted to a radiant tube burner.

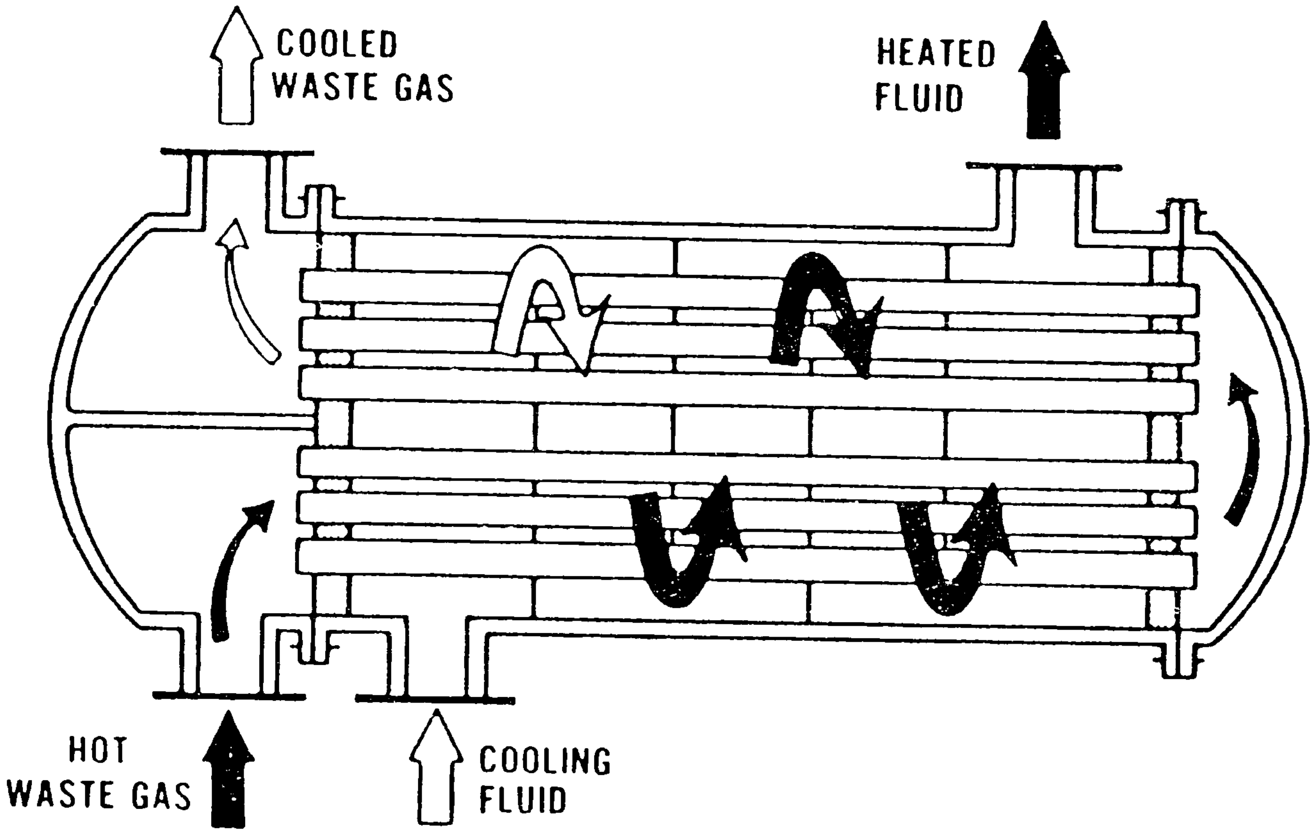
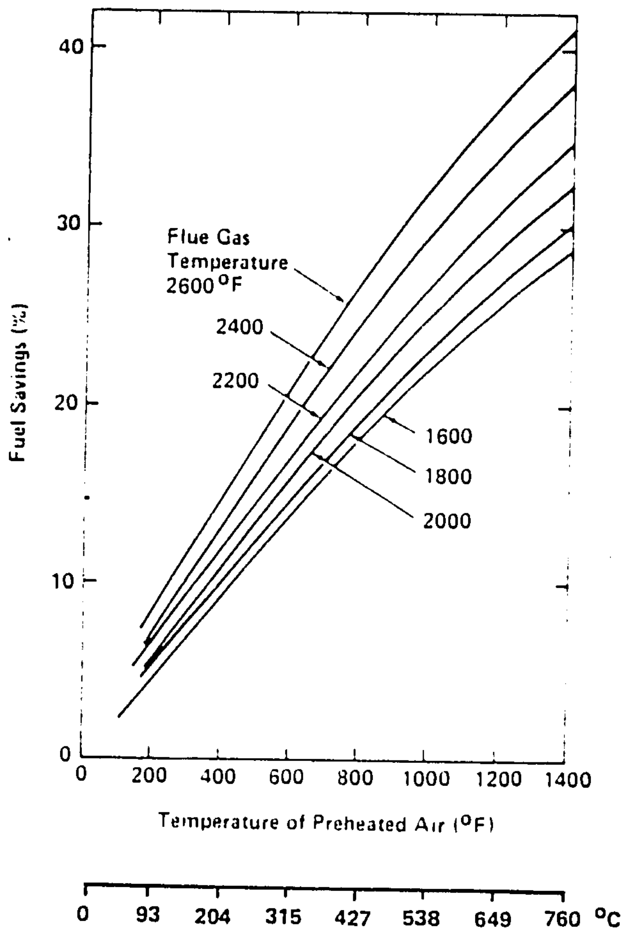


Diagram of convective-type recuperator.

Exhibit 12.11

Potential Fuel Savings From Preheating Air



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If recoverable energy is not available on a regularly scheduled or continuous basis, it is usually best to return it to the same system that produced it. An example is using stack gas heat from an intermittently operated furnace to preheat the combustion air for the same furnace. In this application, waste heat still exists at a reasonably high temperature and could be useful for drying, even if it has to be supplemented during furnace shutdown by an auxiliary heater.

Insulation

Furnace insulation that is inadequate or in poor condition can waste large amounts of energy, usually in a form that is not readily recoverable. It is possible to get an indication of the importance of the losses by measuring the temperature of the outside furnace walls and roof. A temperature of 70°C-121°C indicates that the losses are reasonable. A temperature of 260°C or higher means that the losses are probably quite large. An estimate of the energy loss per unit of area per hour as a function of outside wall temperature is shown in Exhibit 12.12.

When installing new insulation or when retrofitting, ceramic insulation fiber should be considered instead of conventional fire brick. Ceramic fiber offers distinct advantages:

- It has only one-third to one-half the heat conductivity of fire brick and may be installed in correspondingly thinner layers for a given heat loss.
- It has a heat storage capacity of approximately one-tenth that of an equivalent layer of insulating brick. This feature saves both energy and time in startup, or in reheating during a batch cycling operation.
- It is immune to failures by spalling or cracking caused by rapid heating and cooling.
- Its light weight makes it possible to install it without major rebuilding of a furnace.
- It is available either in blanket, board, or spray form and can be installed either way.

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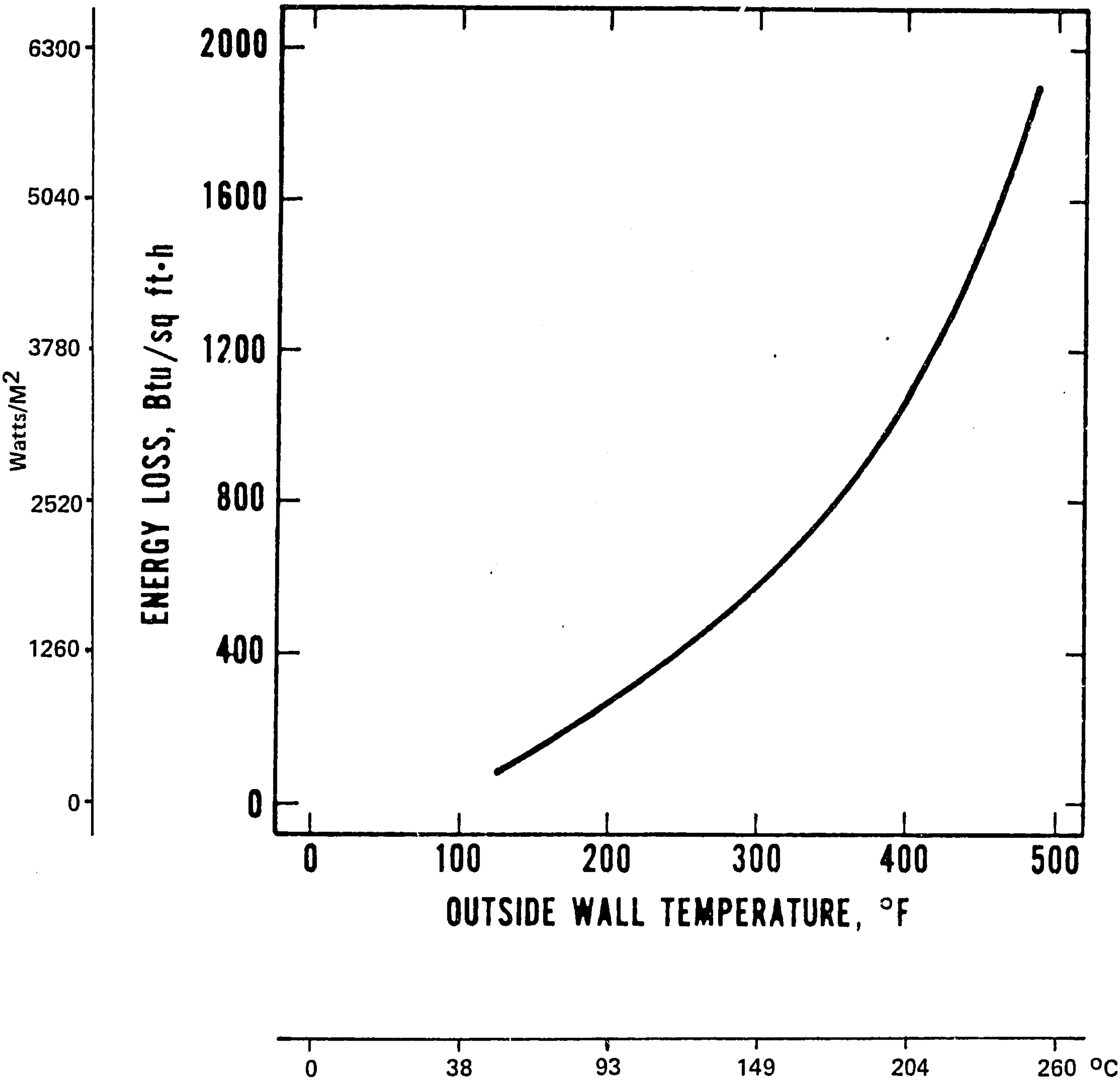
Exhibit 12.12
Energy Loss from Furnace Walls Versus Outside Wall Temperature



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It has some disadvantages:

- Since it is very poor in physical strength, it cannot be installed on furnace floors or in other areas where it would be subjected to mechanical abrasion.
- Since its insulating properties depend on its high porosity, its use should be questioned in any service where the pores might be plugged by deposits from fumes or by particulate matter.
- It is intended for installation on the hot side of furnace walls or roofs. A blanket of fiber on the cold side of an existing furnace wall may well cause some of the interior layers of brick to heat beyond their useful service temperature.

Ceramic fiber insulation installation costs are typically $120 per square meter per 50 mm thickness in the United States. The major portion of the cost is the labor for installation. Because of the delicate nature of the material, it must be installed with care. Savings by using ceramic fiber in furnaces and kilns of up to 5 percent of the energy input into the furnace have been realized.

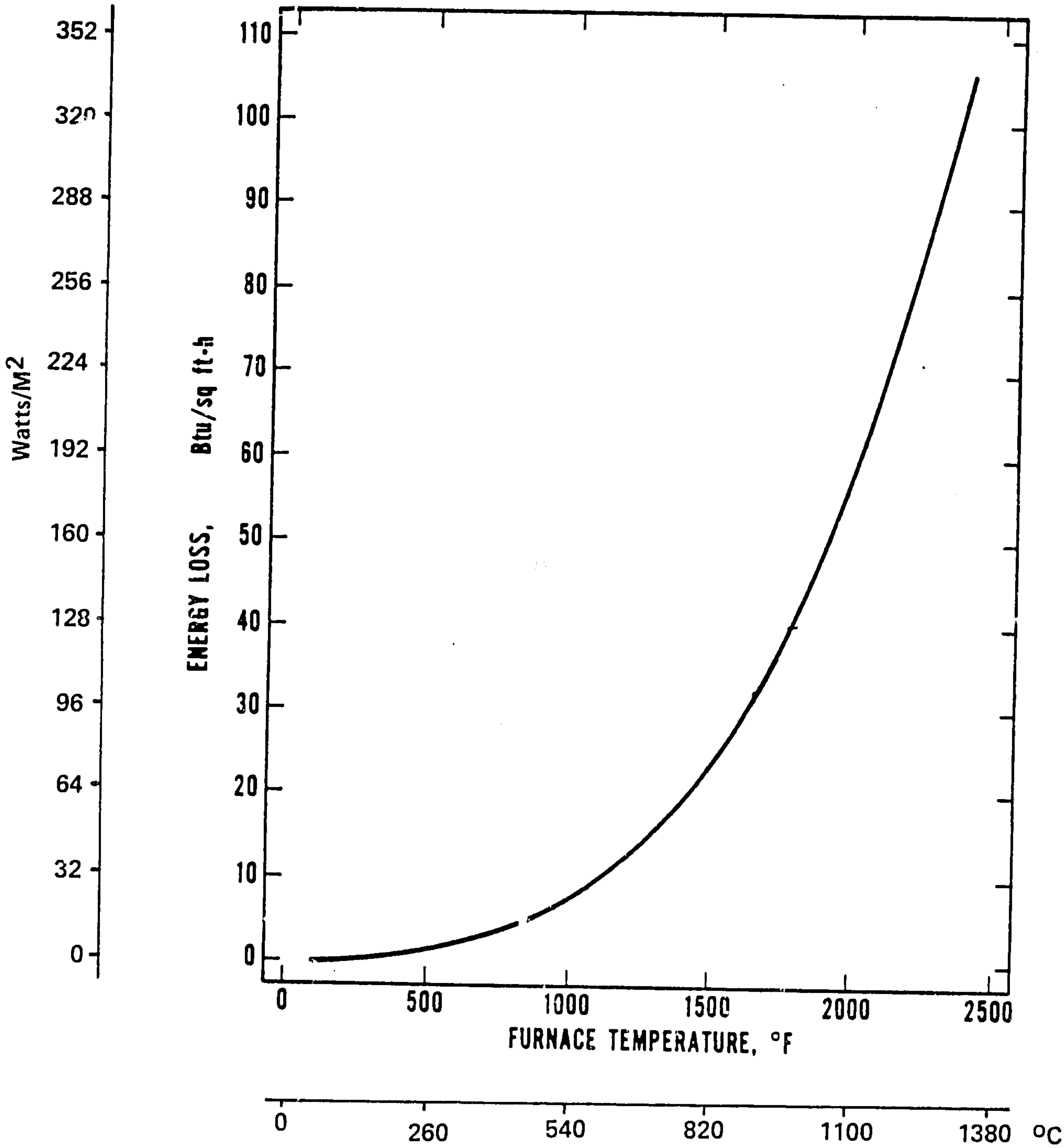
Reduction of Openings and Leaks

Open ports or leaks in a furnace system waste energy by radiation losses and losses from gas flow through the openings, or a combination of the two. The amount of heat loss is linearly proportional to the area of the opening and is approximately proportional to the fourth power of the absolute temperature. The rate of energy loss is shown in Exhibit 12.13. Radiation losses can be reduced by the use of high-temperature chain curtains, which reflect about 70 percent of the heat back into the furnace. The energy savings are not major, but a typical chain curtain will recover its capital investment in less than 1 year. Chain curtains in the United States cost around $8,000 per square meter.

Outward gas flow through a port or leak is generally not a major source of energy loss. Excessive gas flow may be caused by a poorly adjusted furnace pressure control system. Most furnaces operate with positive pressure. If the leakage is high, check

Exhibit 12.13

Energy Loss by Radiation Through Openings Versus Furnace Temperature



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the control system. If the leak is merely completely burned hot gas from the furnace, it represents a small amount of exhaust gas that otherwise would have been wasted up the stack. If the outward leak results in long flames outside the furnace, it represents incomplete combustion, probably the result of a too-rich fuel/air mixture. Such flames represent an energy waste and should be eliminated by proper adjustment of the amount of combustion air.

The **infiltration of cold air into the furnace represents a serious energy loss.** Every kilogram of excess cold air leaking into a 1,200°C furnace wastes 2,370 kJ. Such infiltration commonly occurs because there tends to be a slight vacuum near the bottom of the combustion chamber in the absence of a well-adjusted flue damper. A "chimney effect" causes the pressure to be lowest at the furnace floor. Pressure gradually rises to the local barometric pressure at the point where the stack exhausts to the atmosphere. The pressure difference (and, hence, the volume of the air infiltrated and the amount of energy lost) depends on the furnace temperature, the height of the flue gas exit above the furnace floor, and the size of the opening through which cold air is entering.

Idle Equipment Shutdown

When heating equipment is out of service, because of scheduled shutdowns or interruptions in production, energy can almost always be saved by allowing the equipment to cool and reheating it later. If the shutdown time is short, it may be best to let the equipment cool to some intermediate temperature, to idle it at this reduced temperature for a period, and then reheat it to the operating temperature.

Unfortunately, there seems to be no law as to when to shut down, when to idle at lowered temperature, and when to hold at operating temperature. The decision depends not only on the projected down time, but most importantly on the characteristics of the specific piece of equipment under consideration. To reach a decision that will save the most energy, one needs several pieces of information:

- Time required for the equipment, with burners off, to cool to room temperature and several intermediate temperatures

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- Rate of fuel flow required to idle at operating temperature and at each of the intermediate temperatures
- Time required to reheat from room temperature and from each of the intermediate temperatures
- Total fuel required to reheat from each of the above temperatures
- Maximum rate of temperature change that will not result in equipment damage.

With this information and a projected down time schedule, the cycle that uses the least fuel is easily determined.

Reduction of Losses During Recycling

When a batch furnace is opened to remove one load and put in another, large amounts of energy are lost through radiation and cold air infiltration. The major source of the energy lost is the stored heat or sensible heat in the hot furnace walls, floors, and roof. The loss mechanisms are both radiation and cold air infiltration through the open door(s). Normal heat loss by conduction through the furnace walls is usually small when compared with this "open-door" loss. Another (usually less important) source of energy lost is the sensible heat of any trays, fixtures, or carriers that must be heated and cooled for each cycle. These facts point to several techniques of conserving energy:

- Since the heat flow through open doors is a function of time, energy is saved by keeping the open-door time as short as possible. If, for example, one must wait 10 minutes for arrival of the next batch of product to be treated, shut the door during the waiting period.
- Supporting trays and fixtures should be designed for minimum heat capacity. In general, this means designing to minimum mass.
- The most important method of saving energy in a furnace that must be cycled is to use an insulating material that has a very low heat capacity per unit volume, such as ceramic fiber.

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Continuous Efficiency Monitoring

To ensure proper energy efficiency over long periods of time, continuous monitoring devices should be used to track such key variables as flue gas temperature, fuel consumption, and furnace lead. The most efficient of furnaces and kilns can drift from its optimum adjustments unless it is monitored on a regular basis. Each system should be tailored to the system needs but include:

- A complete flue gas analysis is a useful method of monitoring furnace efficiency and should be completed monthly.
- For major energy-use furnaces, continuous indicator or recording oxygen analyzers. These devices will rapidly show any change in the amount of combustion air or infiltration air.

Summary

Before considering implementation of major capital investment items, such as waste heat recovery, a full evaluation of furnace operation should be conducted, including a heat and mass balance at both current and projected operating rates. Such a balance is presented in Session 10 for a cake oven, but it is illustrative of how to build a balance for other furnaces and kilns.

SESSION 13: DRYERS

INTRODUCTION

There is a large range of drying plants in industrial use. Drying of materials is completed in a number of ways:

- Evaporation by direct heating
- Evaporation by air drying
- Dehydration
- Freeze drying
- Dielectric drying.

The session focuses on drying by thermal methods and does not discuss alternate methods such as the microwave or dielectric dryer. The session outlines common types of drying plants, as well as presenting housekeeping and maintenance procedures to ensure optimum performance. Modifications to existing plants to improve energy efficiency are also detailed.

TYPES OF DRYERS

Dryers operate either on a batch or continuous basis. There are too many types to permit full coverage in one session, but salient types and features are presented of more common dryers.

Essentially, dryers can be classified either as (see Exhibit 13.1):

- Convection dryers
- Contact dryers
- Specialized dryers.

Convection dryers are sometimes referred to as direct dryers as the evaporating medium, usually air or hot gases, impinges upon or makes direct contact with the material to be dried. Contact (or conduction) dryers are occasionally referred to as indirect dryers

Exhibit 13.1

Types of Dryers

Dryer type	Principal mode of operation
Convection dryers	
Drying rooms	Batch, continuous, semi-continuous
Cabinet dryers (tray, etc.)	Batch
Conveyor dryers	Continuous
Tunnel dryers (truck)	Continuous, semi-continuous
Rotary dryers	Continuous
Vertical cylindrical dryers	Continuous
Spray dryers	Continuous
Air-swept rotary mills	Continuous
Pneumatic dryers	Continuous
Contact dryers	
Platen dryers	Batch
Cylindrical dryers	Continuous
Vacuum dryers	Batch
Freeze dryers	Batch
Specialized dryers	
E.g., fluidized-bed, radiant, high-frequency dryers	Batch, continuous, semi-continuous

as evaporation takes place after heat has been supplied by conduction through a metal wall or plate.

The simplest type of drying (and the one that was first used) is done under the sun and prevailing ambient conditions. Open-air drying has been used for many different materials, including textiles, ceramics, and paper. However, because of constraints on production times, open-air drying has been replaced by custom-designed drying plants. The classification system is a broad one, and some dryers are a combination of both categories. The following paragraphs outline dryers in use in industrial processes.

Convection Dryers

There are several types of convection dryer:

- Chamber dryers or drying rooms
- Cabinet dryers
- Conveyor dryers
- Tunnel dryers
- Rotary dryers
- Vertical cylindrical dryers
- Spray dryers
- Air-swept rotary mills
- Pneumatic dryers.

Chamber dryers or drying rooms are a modification used to increase the rate of drying of materials in comparison to the open-air dryer. Material to be dried is placed in a room in such a manner to expose the maximum amount of surface area. Hot air is then circulated through the room, often through ducted outlets, to improve air flow over the material.

Thermal efficiency is maximized by reheating and recirculating the drying air through the room. Humidity is controlled by dumping a portion of the recirculating air and replacing it with makeup air. Chamber dryers are used to dry large bodies such as building slabs, bricks, wallboard, fiberboard, clothes, and foundry cores.

Cabinet dryers are basically boxes in which materials are placed on racks or suspended for drying purposes. Air is circulated to bring about drying. Often, materials are placed in trays to a depth of 50-100 mm (2-4 inches), and the trays are perforated to maximize air circulation. Cabinet dryers are used to dry materials such as pigments, chemicals, foot products, ceramicware, and textiles. Exhibit 13.2 shows typical chamber and cabinet dryers.

Conveyor dryers comprise a conveyor open or partly open to the atmosphere, or completely enclosed in a tunnel. The material to be dried passes through the tunnel on the conveyor. Hot drying gases may flow from end to end of the dryer, or upward and downward through perforations in the conveyor and thus over the material.

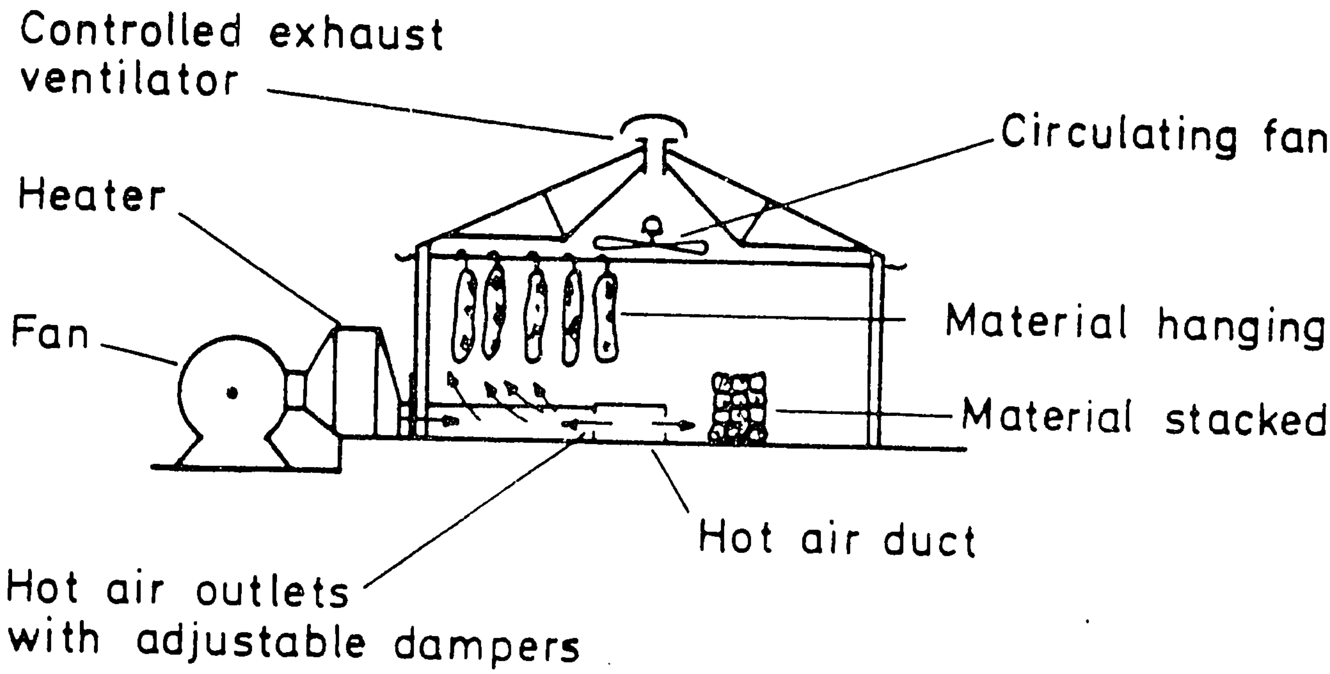
Conveyors are made of woven wire or of sections of perforated metal attached to link chains on each side of the conveyor. Sometimes, the conveyor comprises a fixed perforated plate over which the material is dragged by drag-bars fixed to moving chains on each side of the conveyor. Some use multiple conveyors, one over another; the material to be dried is fed onto the top conveyor and passes from conveyor to conveyor down the dryer.

Exhibit 13.3 shows a semi-open conveyor dryer with recirculating air. It is designed to dry materials with moisture contents of about 70-80 percent.

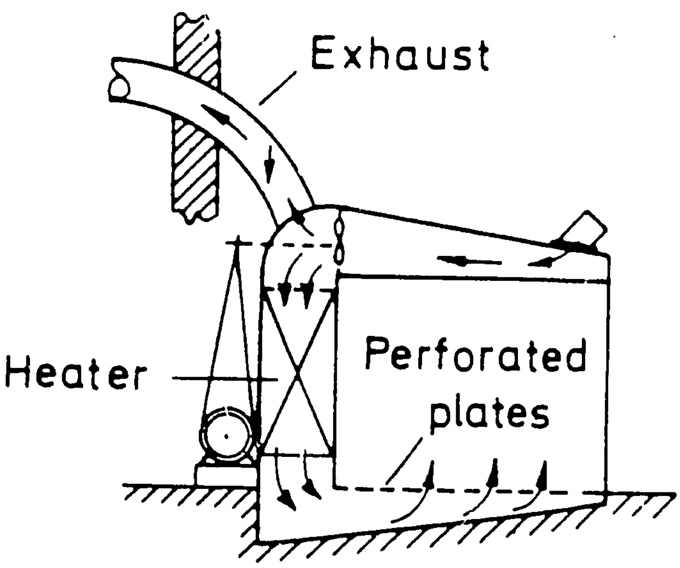
Tunnel dryers are similar to conveyor dryers, but the materials to be dried pass through the tunnel on wheeled trucks (see Exhibit 13.4). When the material on one truck becomes dry, it is pulled out. The other trucks are then pushed forward, a fresh truck being loaded at the entrance to the dryer. The aerodynamics of hot air flow through typical tunnel dryers is shown in Exhibit 13.5.

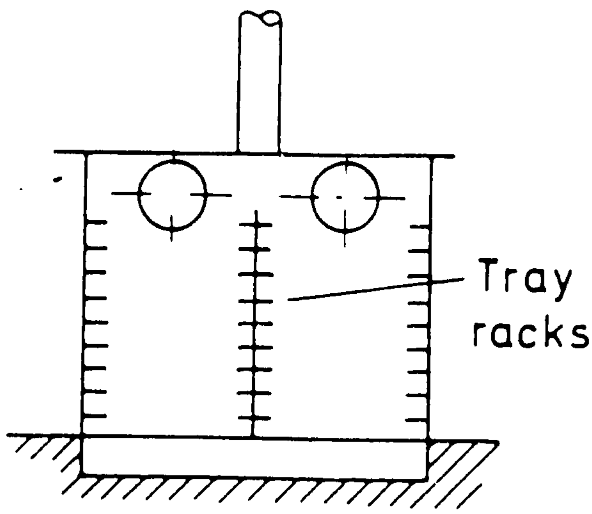
Rotary dryers consist of a horizontal rotating cylinder with a series of longitudinal shelves in them (see Exhibits 13.6 and 13.7). They are used for drying material that must be turned or tumbled in the hot gas stream to ensure uniformity of drying. Hot gases are generally drawn through the cylinder by a fan. Materials to be dried are fed into the cylinder and fall to the bottom. They are picked up by shelves as the cylinder revolves and spill off through the stream of hot gases. The drum is usually set at a slight inclination towards the outlet. The inclination may vary from 1 in 16 for

Exhibit 13.2
Cabinet Dryer



Chamber drier





Section through stove showing propellor fans

Exhibit 13.3

Conveyor Dryer

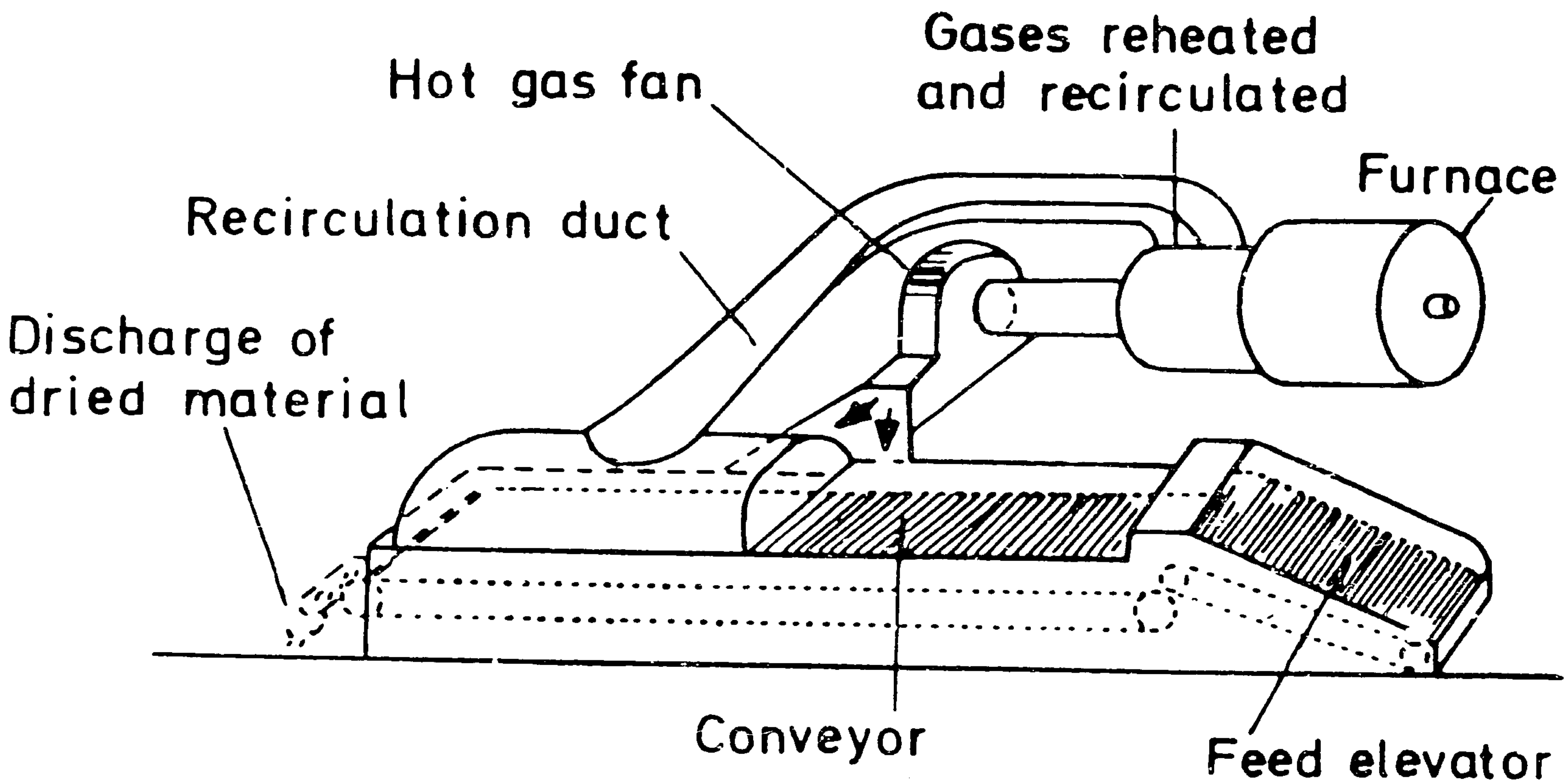


Exhibit 13.4

Tunnel Dryer for Wheeled Trucks

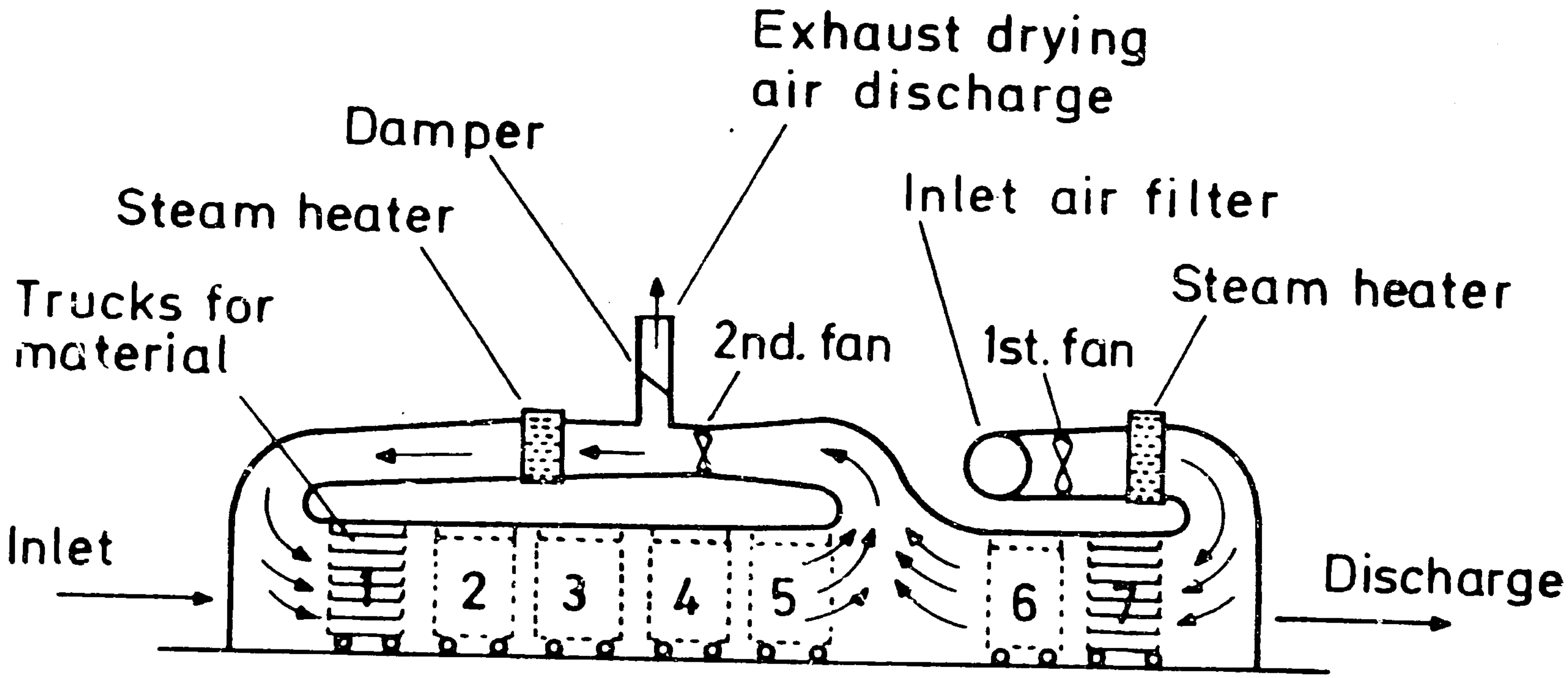


Exhibit 13.5
Gas Flow Through Tunnel Dryers

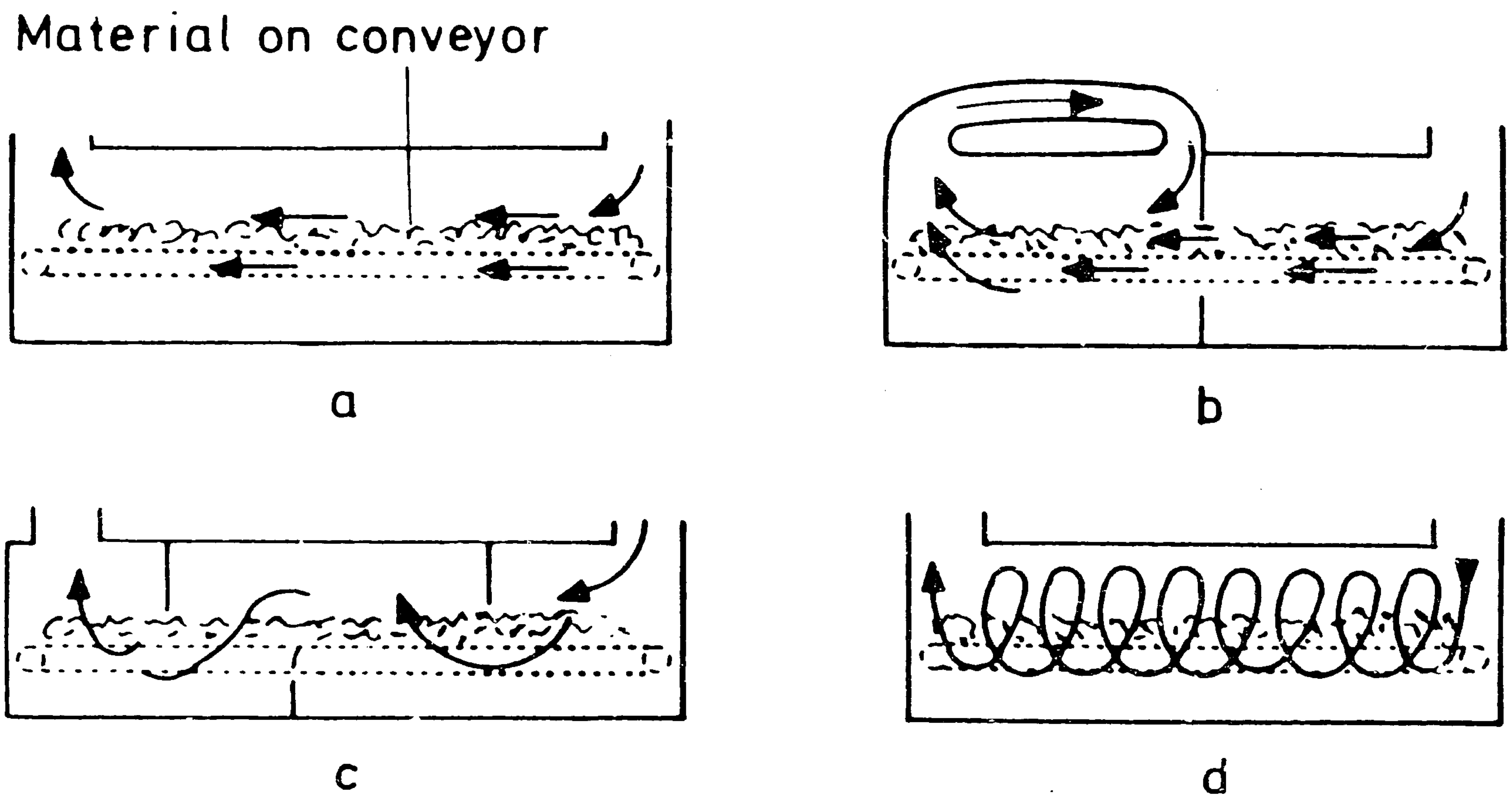


Exhibit 13.6
Single-Shell Rotary Dryer

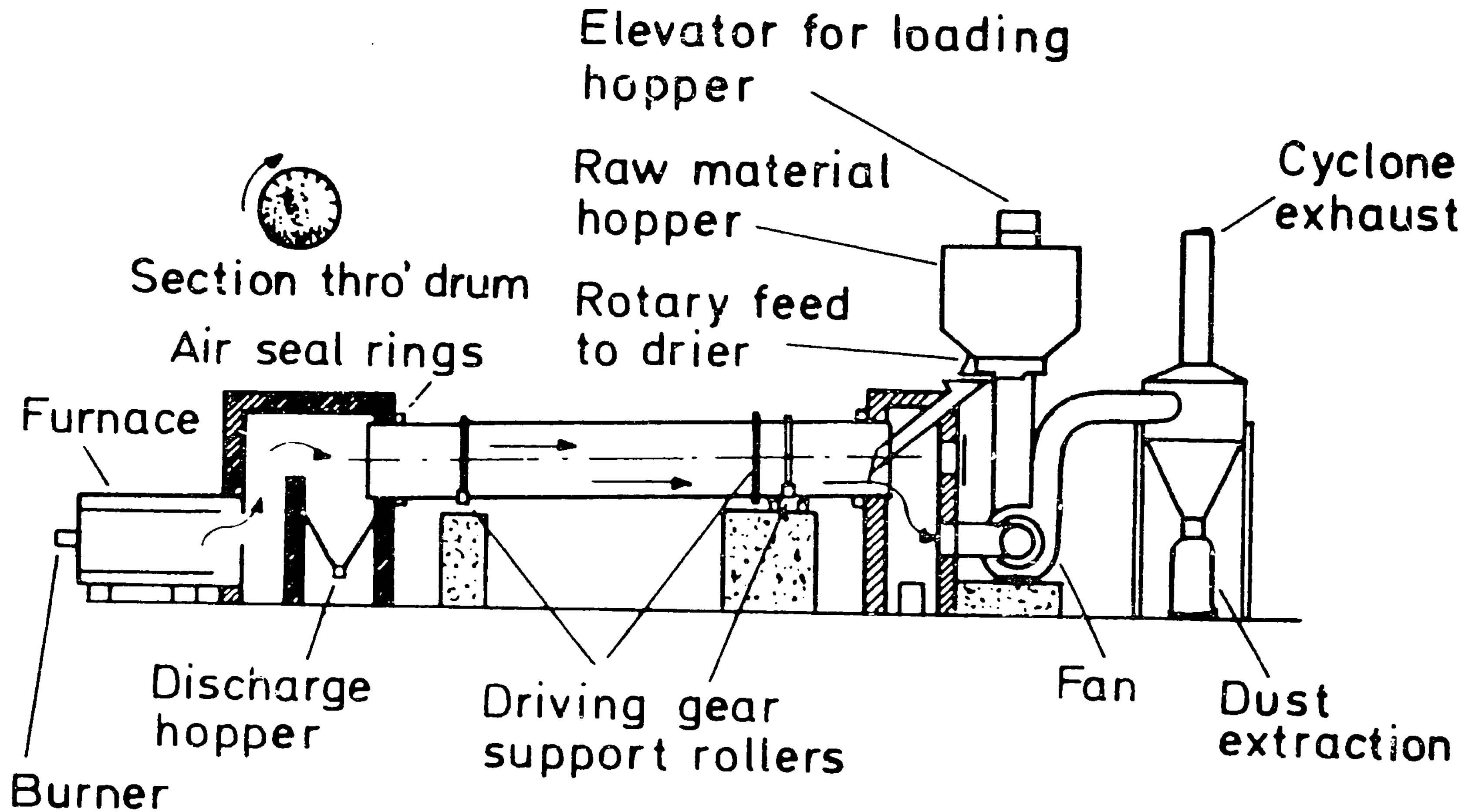


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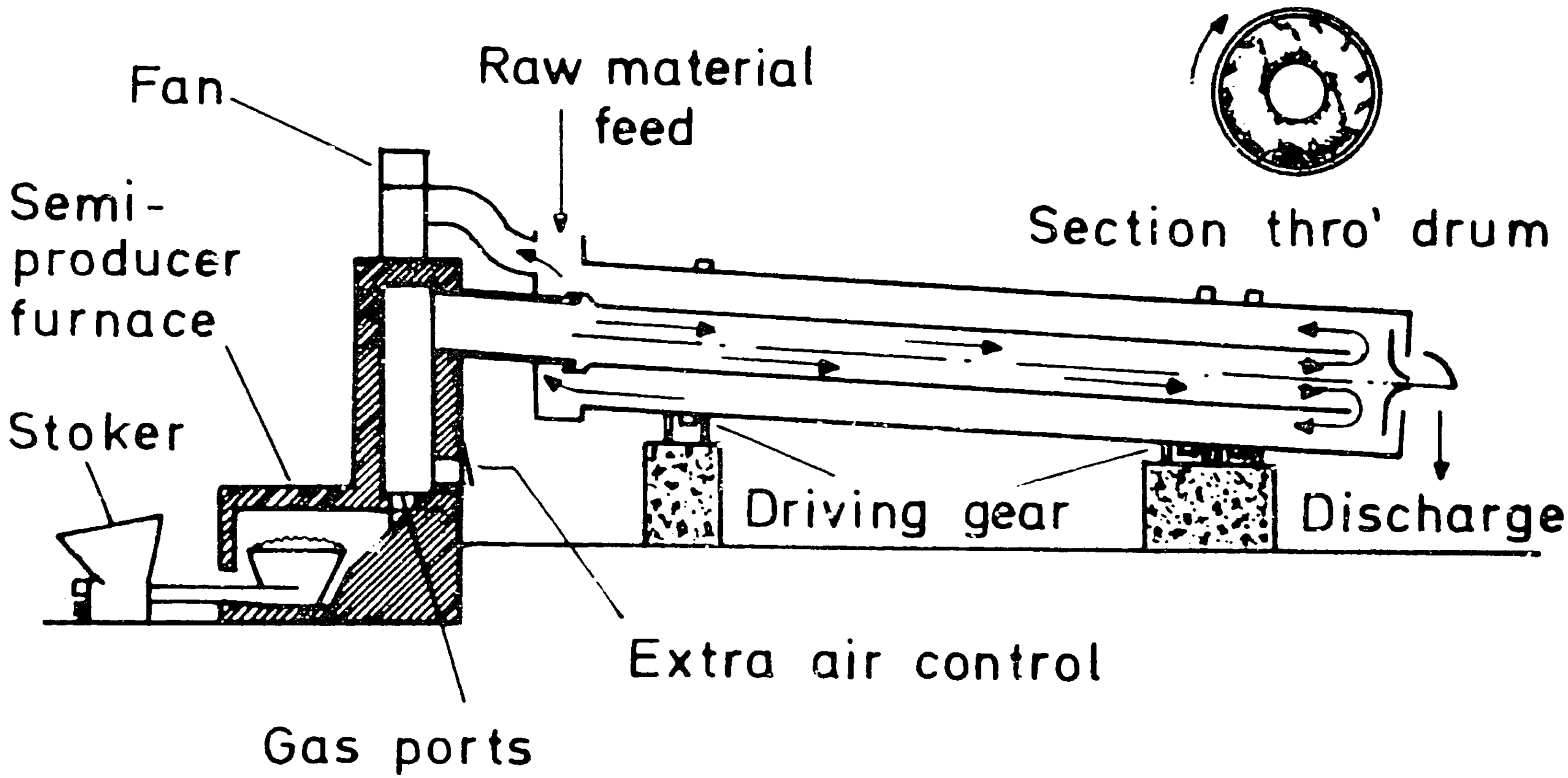
Exhibit 13.7

Double-Shell Rotary Dryer



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quick-drying substances to 1 in 30 or 1 in 40 for those that dry slowly. The incline of the drum, and shape, width, number and form of the shelves, are determined by experience to produce the best showering effect and rate of feed of material through hot gas.

These dryers are used for drying sticky material such as clay, material that is in fairly large lumps, and chemicals. Where possible, the material is fed into the dryer in the opposite direction to that of the flow of hot gases.

Vertical cylindrical dryers consist of a series of concentric shelves encased inside an outer cylinder. Material is fed onto the top shelf and is pushed around and turned over at the same time by a revolving rake or scraper. When the material has moved around once, it falls through a gap in the concentric shelf onto a shelf below. Alternatively, the concentric shelves are fixed to a central spindle and revolve, and material is turned over by a fixed rake. Flow of hot gases is usually outward over one tray and inward over the next. These dryers are used for materials that must be turned when drying and that need relatively long drying cycles. They are often used for drying slurries and pastes in addition to solid materials.

The spray dryer uses a spray mechanism to dry liquid and semi-liquid materials. The substance to be dried is sprayed into a chamber through which hot air or gases pass. The total surface area of the many particles in the spray is very large; this large surface area, together with the movement of the particles, provides ideal conditions for rapid drying. Drying gases can enter the dryer at comparatively high temperatures, because very quick rates of evaporation and heat absorption cause a very rapid fall in temperature; thus, the substance being dried does not rise to a harmful temperature. The heavier dried particles fall to the bottom of the chamber, the lighter particles being carried over in the exhaust gases and collected in a filter-type dust collector. This type of dryer is used predominantly to dry foodstuffs and chemicals.

Air-swept rotary mills combine the action of pulverization and drying into one operation. Material is pulverized in a ball mill while moisture is evaporated by passing a continuous stream of hot gases over the material. The pulverizing action breaks down the material into particle sizes that are carried out of the ball mill by the hot gas stream to a cyclone separator.

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Pneumatic dryers comprise of a vertical drying tube of about 10 meters length (33 feet), a cyclone separator, and an induced draft fan. Drying air is drawn into the base of the tube through an air heater and travels up the drying tube at sufficiently high velocity to convey the largest particles. The material to be dried is fed into the base of the tube by a screw conveyor, cage, sling or hammermill.

The drying air is passed through the mill, where over half of the total heat transfer may take place. While the material is being conveyed up the tube by the drying air, drying is effected in a matter of seconds by surface drying. Air and dried material are then separated in the cyclone, and exhaust air further cleaned by wet scrubbers, bag filters, or electroprecipitators. Total energy requirements for conveying, drying, and separation of the material are high.

Pneumatic dryers are used for drying materials such as chemicals, clay, or sewage sludge in particulate form. Moisture contents up to 900 percent dry basis can be handled by these dryers.

Contact Dryers

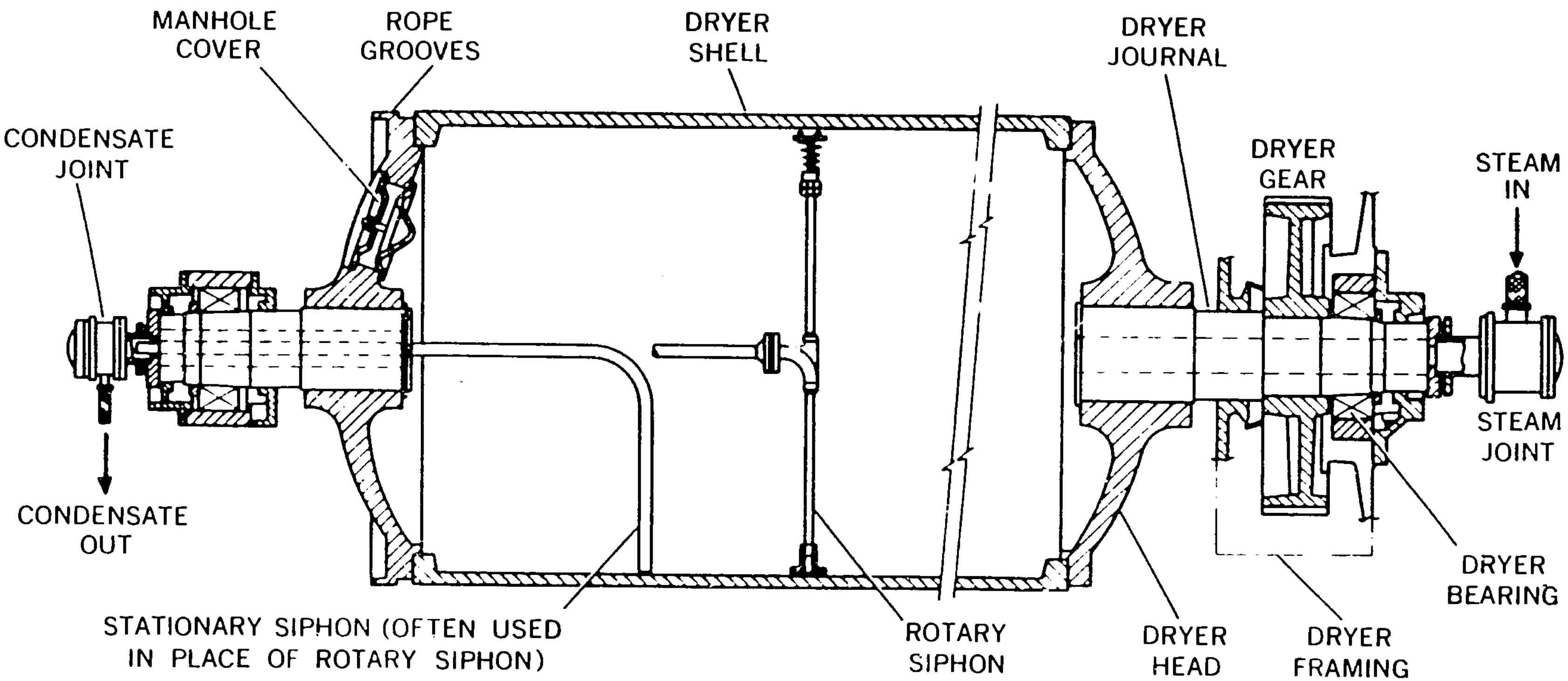
Contact dryers operate by drying through direct application of heat. Major types are:

- Cylinder dryers
- Platen dryers
- Vacuum dryers
- Freeze dryers.

Cylinder dryers are the most common type used and are found predominantly in paper drying. Dewatered pulp is fed onto a series of from one to more than a hundred rotating cylinders heated internally with low-pressure steam, normally around 1-2 bar. A cross section of a typical drying cylinder is shown in Exhibit 13.8. Exhibit 13.9 shows an example of a hooded cylinder dryer.

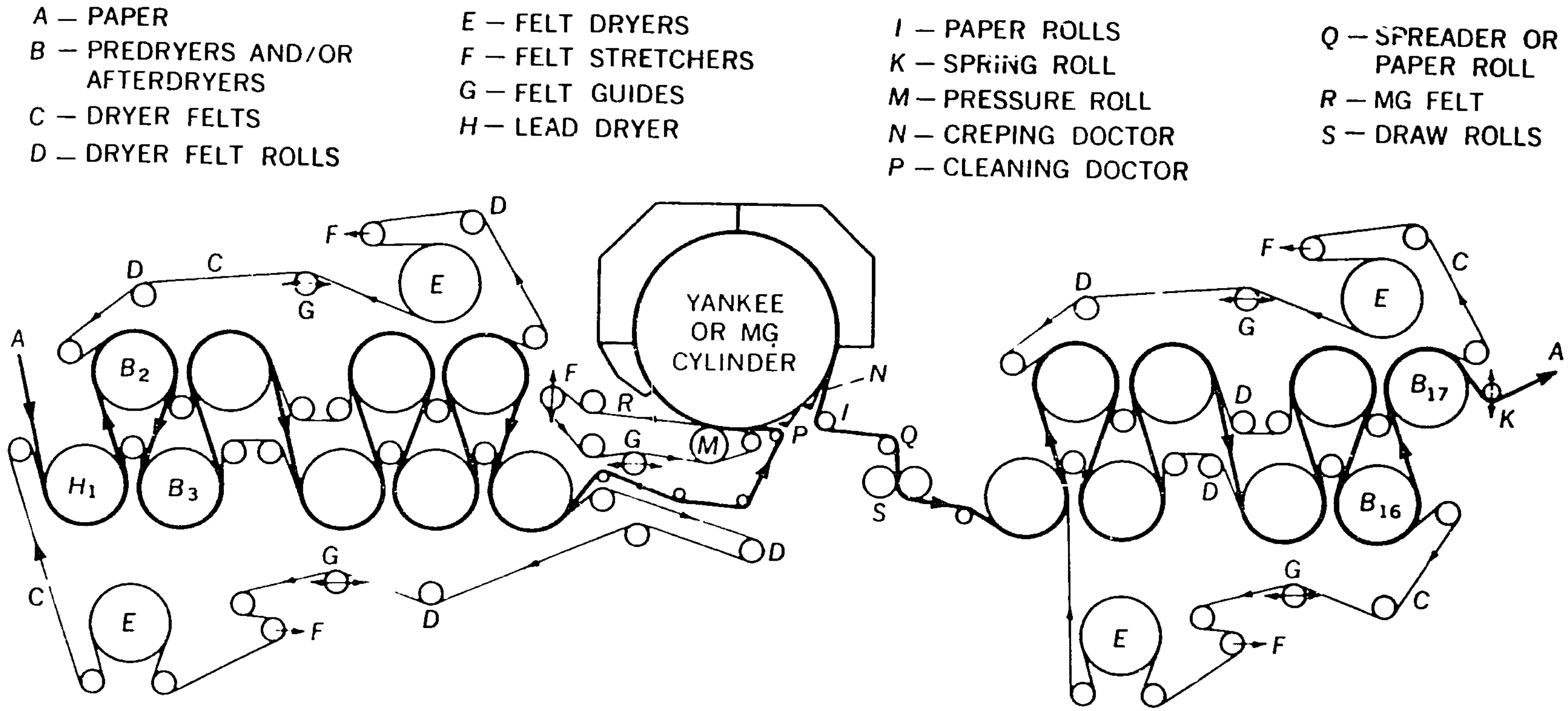
The **platen dryer** comprises two heated plates. Material is placed on one of the plates and then the two plates are brought together. The top plate is lifted occasionally to

Exhibit 13.8



Cross section of dryer cylinder. (Dominion Engineering Works Limited)

Exhibit 13.9



Yankee or MG (machine glaze) cylinder dryer with predryers and afterdryers. (Dominion Engineering Works Limited) permit the product to be moved through the plates. These dryers have only limited application, mostly for drying veneer.

Vacuum dryers are expensive, as drying must be be carried out in vessels or chambers sufficiently strong to withstand external pressure, and a condenser and air pump are necessary to maintain the vacuum and draw off evaporated moisture. The majority of vacuum dryers are batch dryers, as a continuous-feed dryer necessitates the incorporation of a seal device to prevent loss of vacuum when the material enters and leaves the dryer. The great advantage of this type of dryer is that boiling point of water is very much lowered:

Absolute pressure (mbar or 100 Pa)	130	100	70	40
Boiling point of water (°C)	51	46	39	29

When drying in a vacuum, a high rate of evaporation can be maintained at a low temperature; consequently, it is the best method for drying materials that would be harmed by higher temperatures and are difficult to dry, owing to a low rate of diffusion of moisture from the center to the surface of the material. Sugar, chemicals, dyestuffs, rubber, white lead, foodstuffs, and explosives are examples.

Material may be heated before it is put into the dryer. Inside the dryer, heating is done by conduction through contact with the hot steam-heated metal surface of the dryer and, to a lesser extent, by radiation. It is sometimes necessary to provide revolving arms or agitators to turn the material over to equalize its temperature, or alternatively material is spread in a thin layer on steam-heated trays in the dryer.

The thermal efficiency of the vacuum dryer is high, with a steam consumption of approximately 1.25 kg/kg of water evaporated. Very economical working can be effected if exhaust steam is available.

Freeze dryers operate by freezing solid the material to be dried. A vacuum is then applied, followed by a controlled heat input. Ice crystals sublimate directly to vapor without passing through the liquid state. The vapor can be collected as ice on a low-temperature condenser. Energy requirements for freeze drying are high, but heat-sensitive materials such as serums and antibiotics and foodstuff are dried this way.

Specialized Dryers

Of the specialized dryers that are available, the most interesting is the fluidized-bed dryer. An example of a fluidized-bed dryer is shown in Exhibit 13.10. The main element of the dryer is the gas-permeable distributor plate that forms the base of the dryer chamber. Heated air or gas flow through this plate to an induced draft fan, and is exhausted to the atmosphere through a dust collector. Gas velocities through the plate are controlled to produce the product in a fluidized state. Fluidized-bed dryers are used for drying chemicals and food products in granular form or other solids such as coal, cement, industrial sand, or limestone.

HOUSEKEEPING MEASURES

To ensure that dryers operate at optimum efficiency, certain housekeeping and maintenance procedures must be followed.

Problems with dryer operation that cause inefficiency result from one of the following areas:

- Design and construction
- Operation
- Maintenance.

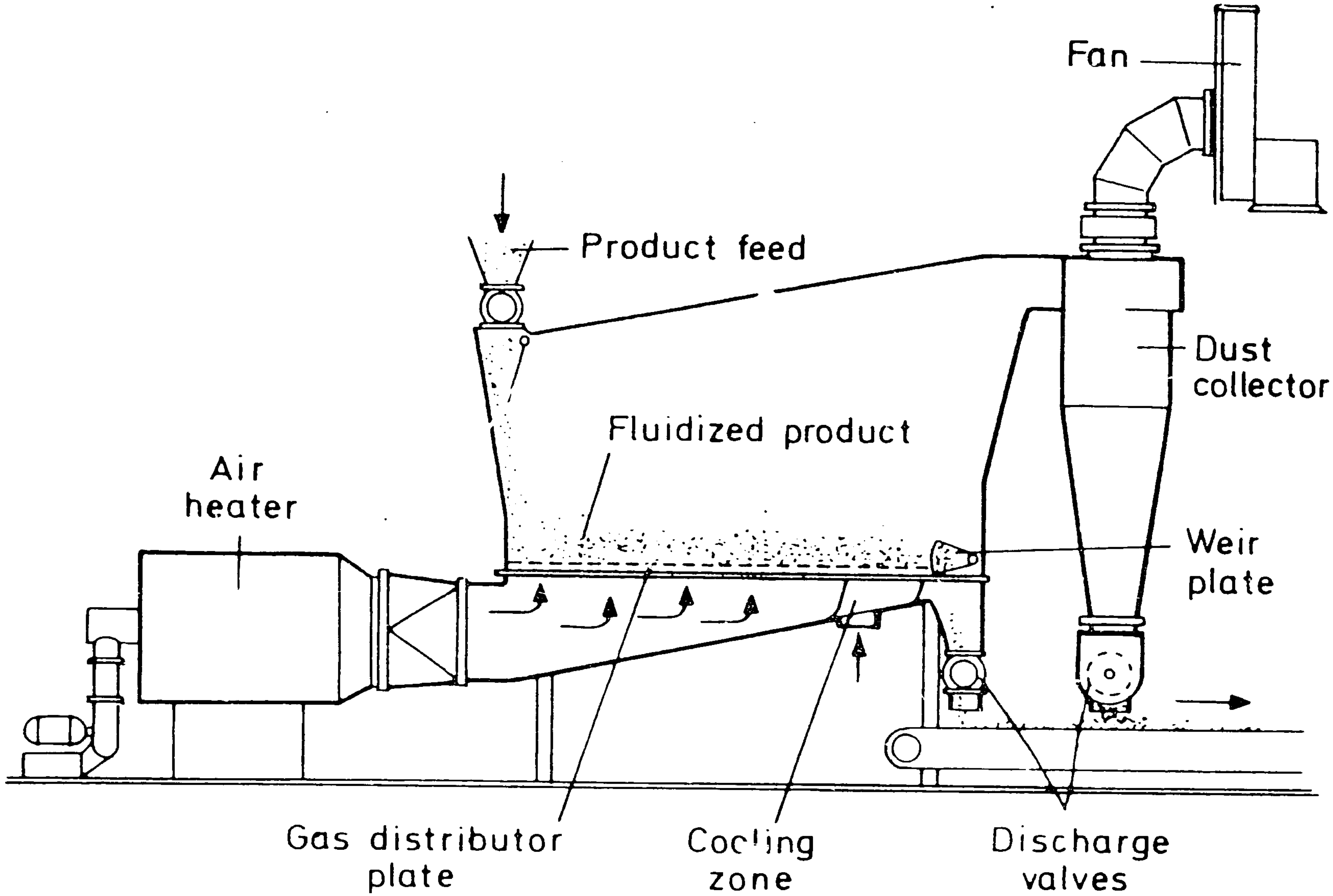
When establishing a maintenance program for the first time, the energy coordinator should determine the status of the dryer under consideration.

The following checklists are presented to indicate some of the information required to set up a program of planned maintenance.

Design and Construction

The data below are required and should be kept by the energy coordinator as part of the overall energy management data base for an industrial plant. Whenever changes

Exhibit 13.10
Fluid-Bed Dryer



or modifications are made, they should be recorded together with subsequent operational conditions arising from the modification.

- Dryer

  - What is the dryer used for?
  - Was it designed for this use?
  - What drying medium is used?
  - Was it designed for this drying medium?
  - Are any burners in use?
  - If there are burners, have they been changed since design?
  - What burners were originally installed?
  - At what capacity or working rate is the plant being operated?
  - What was its original rating?
  - How was the original capacity specified, if at all?
  - Is the present rating:

    correct?

    high?

    low?

- Modification

  - Has the plant been modified since installation?
  - If so, how?

    by rebuilding?

    by changing of drying medium?

    by change of use?

    by adding or removing heat exchangers or ancillaries?

- Ancillaries

  - Are heat exchangers or recirculation systems fitted?
  - Where?
  - Are they still in use:

    effectively?

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ineffectively?

- What exhaust fans are being used?
- Are they the original fans?
- Is the exhaust volume too great or low?

- Construction

  - Who built the dryer?

    If drying company, was it:

    to their own design?

    to user's design?

    If user's design, was it:

    to a standard design copy?

    to the user's own design?
  - Was the dryer soundly built in the first place?
  - Were the initial and final moisture contents of the material correctly specified?
  - Was the most appropriate drying equipment correctly chosen?
  - Was the basis for the choice:

    engineering?

    economics?

    a compromise between both?

    chance?
  - Was the dryer correctly installed?
  - Were the necessary auxiliaries (e.g., pipework, supplementary burners, doors, dampers, pulleys, chains, levers):

    correctly installed?

    connected and tested?

    do records exist recording installation checks and tests?

Operation

The most important record and information that should be kept is a monitor of how the dryer is operated. Regular checks on the following items are imperative to identify decline in performance as well as identification of efficiency improvements.

- Conditions

  - What are optimum operating conditions?
  - What is their basis of specifications?
  - Are these known and understood:
    - by the operators?
    - by management?
  - Are they followed?
  - Are there any operating specifications at all?
  - What are the inlet and outlet moisture contents in current use?
  - What is the desired moisture content?
  - What is the basis for choice?
  - Is air supply condition controlled:
    - with dampers or air supply?
    - with dampers and air supply?
  - How is dryer temperature and humidity changed when this is necessary?
  - Are dryer doors left permanently open?
  - Do exhaust fans operate at one speed irrespective of dryer throughput?

- Control

  - Is dryer correctly instrumented for:
    - fuel consumption?
    - air supply?
    - temperature?
    - humidity?
    - exit gas composition?
    - pressure and draft gauges?
    - steam meter when necessary?

automatic recording?

- Are automatic controlling instruments being:
  correctly used?
  used at all?

- Start and stop

  - Are dryers heated:
    too soon?
    too late and forced?
  - What is the optimum drying rate?
  - Is it known to the operators?
  - Is it known at all?
  - Are dryers always loaded to capacity?
  - If not, is it the fault:
    of operators?
    of management?
    unavoidable?
  - Are dryers maintained at temperature during standby for:
    meals?
    night?
    plant stoppages?

Maintenance

Monitoring and adjusting operating conditions are only part of an overall planned maintenance program. Routine inspection and maintenance must be conducted to minimize breakdown. The following checklist should be completed once a week for a system that operates continuously. All findings should be reported in writing and appropriate action taken. Records should be maintained and reviewed on a monthly basis to determine whether persistent problems are occurring with one or more items and to ensure a timely identification of potentially serious problems.

- Dryer
  - Is dryer structure in good condition?
  - If so, is this:
    - good initial construction?
    - good maintenance?
  - Are dryer doors:
    - in good physical condition?
    - operating as designed, or at all?
    - sealing correctly where this is necessary?
  - Are all gas passages, pocket ventilation systems, and flues:
    - in sound condition?
    - clear of loose material?

- Ancillaries
  - Are supplementary burners:
    - generally clean?
    - affected by dirt or deposited carbon?
    - distorted by overheating?
  - Are pumps, motors, fans, etc.:
    - being kept cleaned and oiled?
    - getting dirty, and overheating?
    - still working at all?
  - Is all thermal insulation:
    - still in good initial condition?
    - maintained in good condition by repair?
    - still in position at all?
    - was it ever there?
  - Are there any leaks in fuel, air, or steam lines?

- For steam-heated dryers:
  - Are the steam traps functioning correctly?
  - Do the drying cylinders become waterlogged?

- What is the temperature profile across the drying cylinders?
- Is the steam pressure adequate for drying to specification?
- Can the steam pressure be reduced?

- For air-heated dryers

  - Are air ducts clear of debris and not blocked?
  - Is drying air directed through slots onto the material to be dried? If so, are the slots clear of debris, and do they direct air only across the width of the material to be dried?
  - Is the air supply at the correct volume, pressure, temperature, and velocity for drying requirements?
  - What is the temperature profile across the width of the material to be dried?

- Instruments

  - Are there any automatic control instruments for:
    temperature?
    humidity?
  - If so, are they still operating?
  - Are instruments regularly checked:
    for zero errors?
    for scale errors?
    for other incorrect operation?

ENERGY CONSERVATION OPPORTUNITIES

This section outlines various cpportunities that can be used to improve energy efficiency. Conservation opportunitics that can be used include:

- Do not dry to a moisture content well below specification unless the product must be subjected to further processing that requires a lower moisture content.

- Use the highest temperature for the drying medium that the material can tolerate without degradation.
- Increase the velocity of drying air in convective dryers.
- Reduce moisture content of material to a minimum by mechanical means before it passes into the dryer.
- Make drying air pass contraflow.
- Reduce radiation losses by use of insulation from dryer and associated ducting.
- Recirculate exhaust gases.
- Install variable-speed exhaust fans and temperature and humidity controllers to regulate exhaust volumes.
- For contact dryers, install a cascading flash steam system that uses condensate from high-pressure drying cylinders to produce flash steam for use in low-pressure drying cans.
- Use infrared heaters to predry material.
- Recover heat from exhaust.

The above are discussed briefly in the following paragraphs.

Drying to a moisture content well below specifications when no further processing is required is a waste of energy. Some overdrying can be tolerated because of the possibility of moisture regain from the ambient atmosphere in which the product is stored before shipping to a customer. Overdrying a material by 1 percent can increase energy requirements by 2-3 percent. Therefore, management should pay special attention to avoid unnecessary drying. Often, the costs of overdrying can be used to justify expenditures for moisture testing instrumentation.

The energy consumption of a dryer is related to the temperature at which the dryer operates. Drying material to low moisture contents can be achieved only by use of hot drying. Therefore, the dryer should be operated at the highest possible temperature that the material can tolerate. Particular care must be taken in the early stages of drying, when it is often possible to seal the outer surfaces of the material before all moisture has been removed from the center of the material.

Increasing the velocity of the drying air in convection dryers can increase the rate of drying, thereby permitting a faster production rate that will in turn reduce overall energy consumption. This measure can be implemented by altering the speed of motors driving the drying air fans or by using a ducted pocket ventilation system. In the ducted pocket ventilation system, air is discharged from small face area slots in the drying air duct onto the surface of the material to be dried. The effects are to break down the water flow on the surface of the drying material and to increase the rate of evaporation and heat transfer. Pocket ventilation systems can be retrofitted to existing convection dryers as well as to cylinder dryers. A pocket ventilation system retrofitted at a cost of $25,000 to a cylinder dryer system consuming 21 GJ of steam per hour showed a savings of about 1.5 percent of the energy input, giving a simple payback of 2.4 years.

Reducing the moisture content of a material before it enters the dryer is a good way to save energy. A one-percent increase in initial moisture content can raise energy consumption requirements by 5 percent. If existing operational conditions such as altering press pressure can be used to reduce the initial moisture content without adversely affecting the material to be dried, it should be done. However, it is not usually possible to economically justify retrofitting or replacing the existing means of mechanical moisture removal on energy savings alone.

Dryers in which the air and drying material travel in opposite directions have better energy efficiency than similar-sized counterflow dryers. However, the relative improvement is not usually sufficient to justify retrofit of existing units. This measure is more applicable when a new dryer plant is being designed.

Insulation can be used to reduce heat losses from the surface of the dryer. Radiated losses from dryers are normally between 5 and 10 percent of the fuel input. Dryers operate at relatively lower temperatures than furnaces and kilns; therefore, the amount of savings is not as great. However, 2-3 percent typically can be saved by insulating the surfaces. Payback periods depend upon the type of insulation chosen and the labor used for installation. Fiberglass or mineral wool insulation costs about $80 per square meter per 25 mm of thickness installed, whereas ceramic fiber insulation costs are typically around $120. Simple paybacks of about 3 to 5 years are typical for dryer insulation.

One of the most effective ways to improve the efficiency of a dryer is to recirculate some of the exhaust air. When hot air is exhausted from the dryer, it is not normally saturated. By recirculating exhaust air in the dryer, energy will be saved. Usually up to 15 percent of the exhaust can be recirculated, with energy savings of 7-10 percent achieved. It is necessary to include humidity monitoring and dampers in the system that permit the exhaust to be either dumped or recirculated. Recirculation will raise the humidity level in the dryer, so it will be necessary to discard some of the exhaust for makeup air.

Recirculation systems are becoming more sophisticated with the advent of solid-state electronic variable-speed motor drives. It is now possible to use an automatic control system that will regulate the speed of the exhaust fans and hence the exhaust flow and recirculation with respect to temperature and humidity. For a dryer producing 1 tonne per hour of fiberboard, an automatic control system was specified that would produce approximately $40,000 of savings annually for a capital expenditure of $50,000.

Cascading flash steam systems can be used to reduce energy consumption in cylinder dryers that operate with both high- and low-pressure steam. Condensate from the high-pressure drying cylinders is allowed to flash to produce steam at a lower pressure and subsequently reused in the low-pressure cylinders. The cost of these systems depend upon a number of factors (i.e., the amount of flash steam available, the relative pressure difference between the cylinders, and steam generation costs). Systems have been installed where simple paybacks were under 3 years on a cylinder dryer producing 2 tonnes of paper per hour. The system was installed at a cost of $50,000.

Infrared heaters can be used to predry the material before it enters the dryer. Energy savings depend on the characteristics of the material, but typically 1-2 percent of the fuel input can be saved. A system for a fiberboard dryer operating at a production rate of 0.5 tonne per hour was specified for installation at a cost of $25,000. The fuel savings were estimated at $6,000, giving a simple payback of just over 4 years.

Heat can be recovered from the exhaust of a dryer even if a recirculation system is fitted. Typically, a heat recovery system will include an air-to-air economizer to preheat drying air and a direct-contact water heater to condense the flue gases. The air-to-air economizer usually will recover 25 to 35 percent of the heat in the exhaust,

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whereas the direct-contact water heater can recover a further 15-25 percent of the heat in the exhaust. A system was specified for a dryer producing 1 tonne per hour at a fiberboard plant at a cost of $150,000. Energy savings were projected at $60,000 per year, giving a simple payback of 2.5 years.

Before considering implementation of major capital investment items, such as exhaust gas recirculation or heat recovery, a full evaluation should be completed, including a heat and mass balance of the dryer at both current and projected operating rates.

As emphasized in the previous sessions, identifying the proper actions to be taken to improve energy efficiency requires the building of the energy balance and a good understanding of plant operations.

SESSION 14: STEAM SYSTEMS, INSULATION, WASTE HEAT RECOVERY SYSTEMS, AND THERMAL FLUID HEATERS

INTRODUCTION

This session discusses the factors influencing the performance of steam systems, insulation, waste heat recovery systems, and thermal fluid heaters. Brief descriptions of various types of equipment are given, together with housekeeping measures and equipment modifications that can be implemented to save energy.

STEAM SYSTEMS AND INSULATION

The steam distribution system is an important link between the boiler and the process plant. Money spent on effective steam generation and use can be wasted unless the distribution system conveys steam effectively. Exhibit 14.1 shows that losses around a typical steam cycle can often reach 40 to 50 percent.

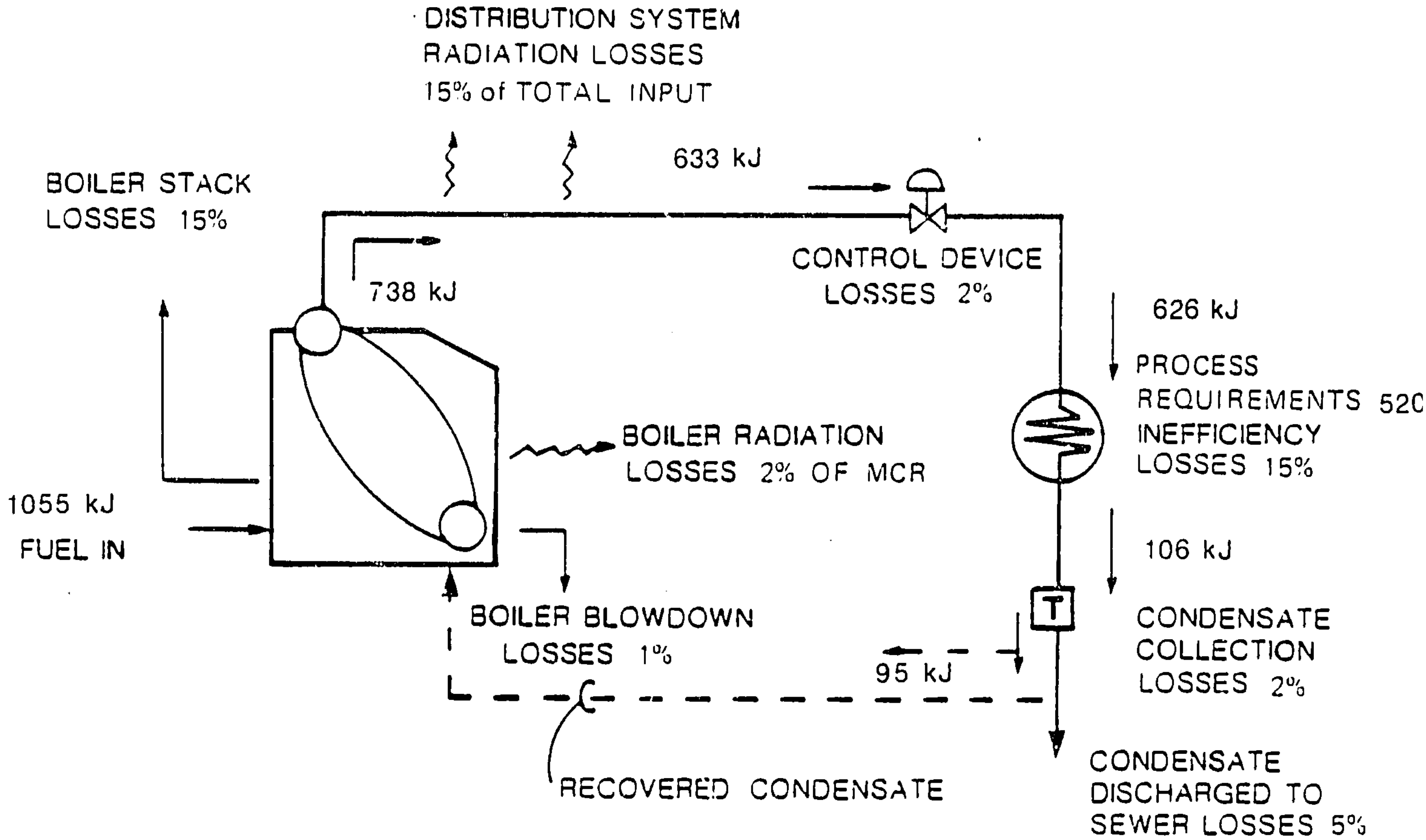
The distribution system should deliver steam at the correct pressure, in sufficient quantity, and dry and air-free. Many processes have critical temperatures at which a change of state of the product is brought about. A typical example is a rubber process that must be completed between 150°C and 154°C for proper bonding to occur. Below 150°C, bonding is inadequate; above 154°C, the rubber hardens and produces an inferior product. This imposes on the plant engineer the duty to deliver steam at the right conditions and in the right quantity to satisfy the process requirements.

Attention must be paid, therefore, to the following aspects of steam distribution:

- Pipe sizing
- General layout and trapping
- Steam quality
- Insulation
- Pressure reduction.

Exhibit 14.1

STEAM CYCLE EFFICIENCY



TOTAL SYSTEM LOSSES = 40% TO 50%

Pipe Sizing

To deliver the right amount of heat as steam requires the correct pipe size. If the pipe is too small, there will be a high pressure drop around the system and the process will be starved. Oversized pipe will not be detrimental to the process but will involve an excessive initial capital cost, together with unnecessarily high running costs owing to excessive waste by radiation loss.

Pipe sizing techniques are based on two methods -- velocity in the pipe or pressure drop through a system. Both methods assume an unknown factor: velocity calculations are based on specific steam volumes, whereas pressure drop calculations assume pressure drops per unit length.

Velocity sizing techniques, however, do not account for length of travel, which means that pressure drops can become excessive and the quantity of heat required is not supplied. Pressure-drop sizing is thus the preferred method, except in the case of direct steam injection. Where steam is injected into a vat, the pressure at the point of injection is governed by the head of the liquid above the injection point. Using pressure drop sizing produces abnormally high velocities, which can cause noise and erosion, especially if the steam is "wet" (i.e., contains relatively large quantities of water).

The calculations associated with pipe sizing can be complex and are beyond the scope of this session. Pipe sizing calculations are normally performed using computer programs.

General Layout and Trapping

Any steam main will condense some steam owing to radiation heat losses from the surface of the pipe. For example, a 100-mm (4-inch) insulated pipe 30 meters long in 10°C air will condense 16 kg of steam per hour. This amount represents less than 1 percent of the pipe capacity, but at the end of an hour the pipe would contain not only steam but also 16 liters of water. Provision must be made to remove this water from the steam main, or the main would eventually become flooded.

It makes good sense to run the steam main with a fall in the direction of the steam flow to aid draining. Steam typically travels at velocities between 65 and 80 km per hour. If condensate were draining in the opposite direction of steam flow, it would be difficult for the water to collect and be removed from the pipe. It would make the steam wet and could cause water hammer. Water hammer occurs when a slug of water is forced along a pipe by steam flow. The slug of water is pushed by the steam until the pipe changes direction. The slug hammers against the pipe and can cause erosion and eventual pipe failure.

By designing so the flow of steam and condensate is in the same direction, drain pockets can be situated at regular intervals (30-50 meters), and draining can take place. Drain pockets must be of adequate size to collect the water. Small drain pockets will not cope with the problem, and the main will become waterlogged. A 100-mm drain pocket will serve mains up to 150 mm; a 150-mm drain pocket will serve a 200-mm main, and so on.

To clear drain pockets or points, the plant engineer must select suitable steam traps. The choice of steam traps is fairly wide. Steam traps operate on different principles, but their basic function is to discharge condensate without passing live steam.

In addition, steam traps are used to deal with the problem of air that inhabits the steam system. As steam condenses and is shut off (e.g., at the end of a working day), air infiltrates the piping system through valves, joints, etc. If the pipeline is to function correctly on restart-up, it is necessary to remove air from the system, particularly from the steam trap. If air is not removed, the trap can become airbound and condensate would not be removed from the system. Hence, traps must be capable of removing air from the distribution system.

Broadly speaking, there are four major types of traps:

- Mechanical
- Thermostatic
- Thermodynamic
- Miscellaneous.

To ensure the highest efficiency for heating purposes and for removing condensate, it is imperative that the correct type of trap be selected. Exhibit 14.2 shows the characteristics of the various types of traps. Points that should be considered for selecting the right steam traps are presented in Exhibit 14.3.

A brief description of each type of steam trap follows.

Mechanical (see Exhibit 14.4)

Mechanical traps use the difference in density between steam and condensate. They open to condensate and close to steam by the action of a float that can be either a closed float (hollow ball) or a device shaped like a bucket with the open end facing either upward or downward. The movement of the float operates a valve.

Thermostatic (see Exhibit 14.5)

Thermostatic traps open or close, depending on their body temperatures. At any given pressure, steam has a fixed temperature, but condensate at the same pressure can cool down to a lower temperature. Thermostatic traps operate based on this temperature difference. The valve is operated by a thermostatic element of either the balanced pressure, liquid, or metallic type.

Thermodynamic (see Exhibit 14.6)

Thermodynamic traps work on the difference in velocity between condensate and steam flowing across a simple valve disc. They close to high-velocity steam, but open to lower-velocity condensate.

Exhibit 14.2

CHARACTERISTICS OF STEAM TRAPS

GROUP	TYPE	ADVANTAGE	DISADVANTAGE
Mechanical	Loose Ball Float	No working parts—little maintenance.	Does not release air automatically — need air cock; Poor valve seating with ball.
Mechanical	Float and Lever	Consistent Operation. Cannot air bind.	Subject to damage from water hammer. Can be attacked by corrosive condensate. Can be damaged by freezing. Different duty size required.
Mechanical	Open Top Bucket	Robust. Resist water hammer.	Do not automatically vent air with cock or vent.
Mechanical	Inverted Bucket	Robust. Resist water hammer.	Very slow air venting. Must be primed with water. Water lost by sudden pressure drop or superheated steam can freeze.
Thermostatic	Balanced Pressure	Very small. Free discharge of air. Handle high condensate rates. Not likely to freeze. Adjusts to fluctuating steam pressure. Easy maintenance.	Damaged by water hammer, corrosive condensate. Do not use on superheated steam.
Thermostatic	Liquid Expansion	Discharge condensate at low temperature. Readily discharges. Can be used for superheat. Not affected by vibration, steam pressure, pulsation, water hammer.	Damaged by corrosive condensate. Can cause water log if improperly set.

Exhibit 14.2

CHARACTERISTICS OF STEAM TRAPS (Cont'd)

GROUP	TYPE	ADVANTAGE	DISADVANTAGE
Thermostatic	Bimetallic	Small. Handle large volumes of condensate. Free air discharge. Not subject to freeze. Can withstand water hammer, corrosive condensate. Used over wide pressure range.	Slow response time can cause waterlogging.
Thermodynamic		Wide pressure range. Use for superheated steam. Not damaged by water hammer, vibration. Not subject to freeze. Small. Handle large volumes of condensate. Only one moving part. Can be made to stand corrosive condensate.	Do not operate on low inlet pressure or high back pressure. Subject to air binding on start-up. Noisy.
Miscellaneous	Impulse	Small. Handle large volumes Work over large pressure range. Used on superheated steam. Do not air bind.	Do not give dead shut off. Subject to pulsing. Can be noisy. Subject to water hammer.

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Exhibit 14.3

Choosing the Right Steam Trap

The following is a series of questions that the energy auditor should ask prior to selecting steam traps for a particular operation:

1. What is the highest condensate rate to be handled?
2. What is the lowest condensate rate to be handled?
3. What is the pressure at the trap inlet?
4. Is there pressure at the outlet?
5. Is condensate returned under vacuum?
6. Does the condensate load fluctuate?
7. Is steam locking likely to occur?
8. Is air present in quantity?
9. Must condensate be discharged immediately?
10. Is the condensate return line above the drain?
11. Is there water hammer in pipeline?
12. Is the condensate corrosive?
13. Is the trap to be exposed to external conditions?
14. Is the steam supply superheated?
15. Is the steam supply thermostatically controlled?
16. Is there vibration or excessive movement in the distribution system?

Exhibit 14.4

MECHANICAL TRAP

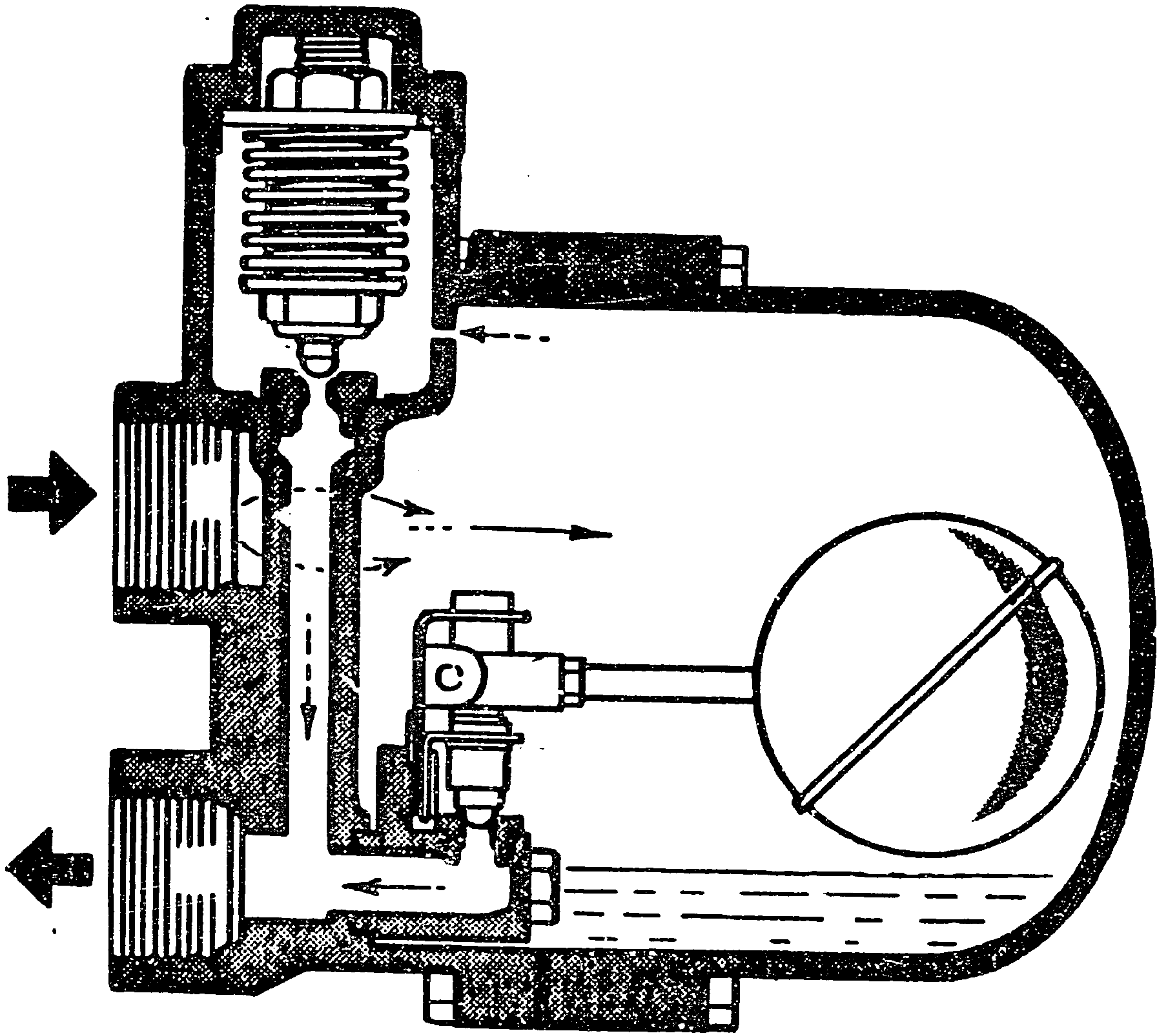

Exhibit 14.5

THERMOSTATIC TRAP

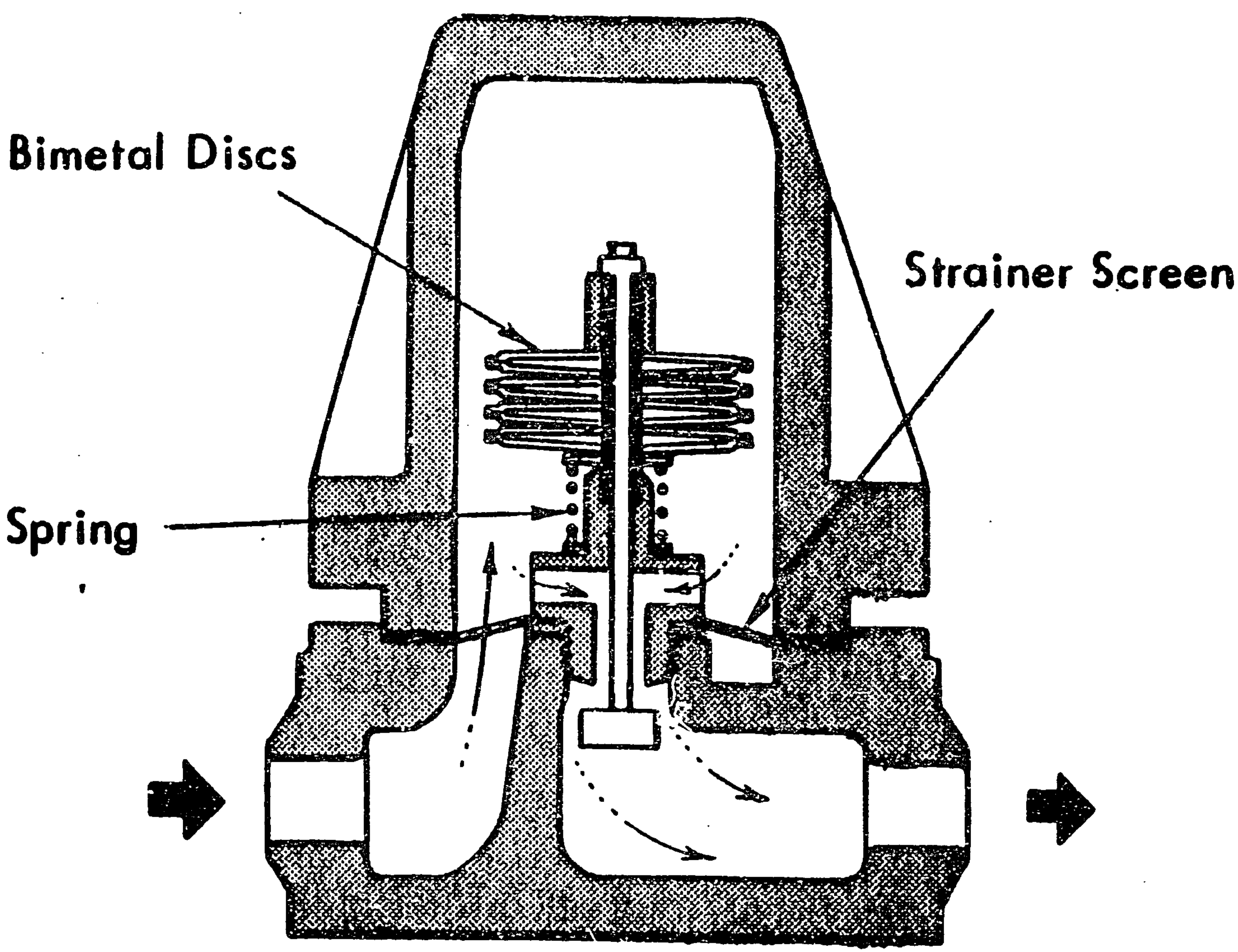

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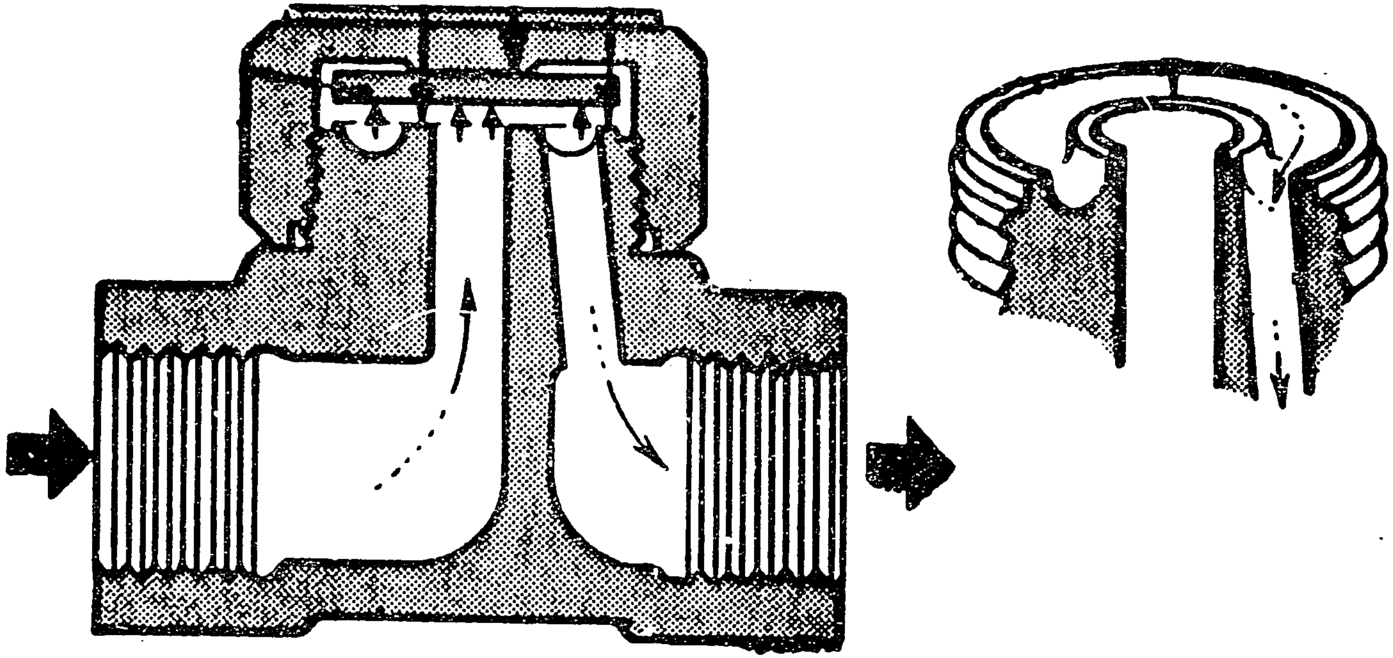
Exhibit 14.6

THERMODYNAMIC TRAP



Miscellaneous

There are a few types of traps in this category. The most widely used are the impulse trap and the labyrinth trap. Impulse traps operate on the throttling effect of several small orifices in series on high-velocity steam or condensate.

Steam Quality

To control steam quality requires removing air and limiting steam wetness.

For a given steam pressure, a mixture of steam and air will be at a temperature lower than that of steam alone. It is essential that air be removed as effectively as possible from a steam distribution system. When a plant shuts down, the residual steam in the distribution system condenses and the main fills with air. When the steam plant turns on again, steam will drive the air out similarly to a piston action. Hence, the speed at which the air is discharged from the system will govern the rate at which the system becomes operational. Often, the main distribution lines use steam traps that provide adequate drainage but have poor air venting characteristics. In this instance, it pays to fit a separate air vent.

Saturated steam usually contains a fair amount of entrained water droplets. The amount of the water droplets is dependent on several factors:

- Level of water below steam offtake
- Peak load effects
- Surging in the boiler
- Pressure on water surface in the boiler
- Solids content of the water.

Poor water treatment is one of the most common causes of wet steam. Experience has shown that a boiler operating with 2,000 ppm dissolved solids delivered steam that was 5 percent wet. When the dissolved solids rose to 3,000 ppm, the wetness became 35 percent.

Water droplets carry no latent heat, increase resistance to heat transfer, and can overload the steam trap and condensate return system. Even with good plant management, it is often impossible to produce dry steam; hence, steam dryers are used. The steam dryer is a separator in which moisture particles impinge on a baffle and drain to the bottom of the dryer, leaving dry steam to pass to the plant.

Insulation

Insulation is vital to reduce radiation losses from the steam distribution system. Typical insulation/radiation losses can run around 10 to 15 percent of the energy input into the boiler. The energy auditor should try to ensure the following:

- All hot surfaces are insulated, including flanges, valves, and fittings.
- Condensate return lines are insulated.
- Insulation itself is protected.
- Insulation is not damaged by moisture or crushing.

Regular inspection of the distribution system should be made to determine the condition of the insulation and the distribution system pipework. Most importantly, the inspection should locate any leakage of steam from the system. The leaks should be attended to immediately, as heat loss can be extensive. For example, an 0.8-mm hole will waste the equivalent of 1,500 liters of fuel oil per year in a system operating at 6.9 bar. Missing or damaged insulation should also be attended to at an early date. Under similar operating conditions as above, a 3-meter length of 150-mm bare pipe can waste 3,000 liters of fuel oil.

Because they are difficult to access, flanges are often not insulated. However, the value of insulating flanges and valves is considerable. A pair of flanges on a 150-mm pipe is equivalent to leaving 0.6 meter of the pipe bare, so if five pairs of flanges can be identified, the waste would be equivalent to 3,000 liters per year.

Similarly, the ends of process vessels such as drying cylinders or calendar beds are often uninsulated. However, one square meter of such a surface operating at 6.9 bar will have a heat loss of about 5 kg of steam per hour. The effect of this loss may not just be found in the extra energy consumption. Space temperatures will become excessive, and energy is often expended to ventilate hot areas. Also, the effect of the ventilation and drafts may cause problems with curing product.

There are five basic types of thermal insulation, which may be used alone or in combination. **Flake insulation,** such as vermiculite or expanded micra, is composed of small particles that finely divide the air space. **Fibrous insulation,** such as glass or rockwool, is composed of small-diameter fibers. **Granular insulation,** such as magnesia, caicium silicate, or diatomaceous earth, is composed of small granules that contain voids. **Cellular insulation,** generally made from glass, rubber, or plastic, is composed of small individual cells that finely divide the air space. Finally, **reflective insulation,** such as aluminum or stainless-steel foil, is composed of parallel thin sheets of foil having high thermal reflectance to restrict radiant heat transfer; the spacing is designed to reduce conductive or convective heat transfer.

Insulation is available in many forms, including batts, blankets, boards, and blocks. In addition, other properties must be considered in selecting insulation: temperature limits, fire hazard classification, dimensional stability, and moisture absorption. The table in Exhibit 14.7 indicates the properties of some commonly used insulation materials.

Calcium silicate insulation products are made from a mixture of lime and silica, with various reinforcing fibers. They have exceptional strength and durability in medium- and high-temperature applications, and also have superior thermal performance at high temperatures.

Fiberglass insulation is supplied in more forms, sizes, and temperature operating capability than any other kind of insulation. While fiberglass insulation incorporating organic binders begins to oxidize at temperatures exceeding 200°C-260°C, the fiber matrix gives the product good integrity, and many fiberglass products are rated above the binder temperature.

Mineral fiber or rockwool insulating products are more heat-resistant than fiberglass and can be used at higher temperatures. However, when used above the binder burnout temperature, the products do not retain their physical integrity very well.

Exhibit 14.7

Industrial Insulation Types and Properties

Insulation type and form	Temperature range (°C)	Thermal conductivity (w/m^oC at T_{mean} (°C)) 25	90	260	Compressive strength (bar) at % deformation	Fire hazard classification of flame spread — smoke developed	Cell structure (permeability and moisture absorption)
Calcium silicate blocks, shapes, and P/C*	to 815	2.57	2.84	3.67	6.9-17.2 at 5%	Noncombustible	Open cell
Glass fiber blankets	to 650	1.66-2.51	2.22-3.40	2.98-5.06	0.001-0.24 at 10%	Noncombustible to 25/50	Open cell
Glass fiber boards	to 540	1.53	1.94	3.54-4.23			
Glass fiber pipe covering	to 450	1.59	2.08	4.30			
Mineral fiber blocks and P/C	to 1,040	1.59-2.36	1.94-2.70	3.12-5.69	0.07-1.2 at 10%	Noncombustible to 25/50	Open cell
Cellular glass blocks and P/C	265 to 485	2.63	3.12	4.99	6.9 at 5%	Noncombustible	Closed cell
Expanded perlite blocks, shapes, P/C	to 815	—	3.19	4.37	6.2 at 5%	Noncombustible	Open cell
Urethane foam blocks and P/C	(-75 to -265) to 105	1.11-1.25	—	—	1.1-5.2 at 10%	25-75 to 140-400	95% closed cell
Isocyanurate foam blocks and P/C	to 175	1.04	—	—	1.2-1.7 at 10%	25-55 to 100	95% closed cell
Phenolic foam P/C	-40 to 120	1.59	—	—	0.9-1.5 at 10%	25/50	Open cell
Elastomeric closed cell sheets and P/C	-40 to 105	1.73-1.87	—	—	2.75 at 10%	25-75 to 115-490	Closed cell
MIN-K blocks and blankets	to 980	1.32-1.46	1.39-1.59	1.46-1.66	6.9-13.1 at 8%	Noncombustible	Open cell
Ceramic fiber blankets	to 1,425	—	—	2.63-3.74	0.03-0.07 at 10%	Noncombustible	Open cell

*P/C: pipe covering.

SOURCE: Manufacturers' literature.

Cellular glass insulation is composed of millions of sealed glass cells, and will not absorb liquids or vapors. While the material is load-bearing, it is also brittle, which makes installation more difficult and causes problems in vibrating or flexing applications.

Expanded perlite consists of a mineral (perlite) that has been expanded at high temperatures to form a structure of tiny air cells surrounded by a vitrified product. While the perlite materials have low moisture absorption as produced, the absorption increases significantly after heating and oxidation. Expanded perlite is rigid and load-bearing, but has lower compressive strengths, higher thermal conductivities, and is more brittle than calcium silicate.

There are three types of plastic foams used for insulation. **Polyurethane/isocyanurate foams** are rigid and offer the lowest thermal conductivities. Sealing is required, however, to resist the migration of an end water vapor back into the foam. These foams also suffer from problems of dimensional stability and fire safety. **Phenolic foams** provide additional levels of fire safety, but are about equivalent to the thermal conductivity of fiberglass. However, they are not usable over very wide temperature limits. **Elastomeric cellular plastics** offer a flexible, closed-cell material most suited to refrigeration piping, plumbing, and vessel applications. Smoke generation is a problem with these materials, and temperature ranges are restrictive.

Insulating refractories consist of two types, fiber and brick. **Ceramic fiber** refractories are made of alumina and silica, while insulating **firebrick** is manufactured from high-purity refractory clays, with alumina added to high-temperature grades.

The selection of new or additional insulation depends on a number of factors. The properties of the insulating material must be matched to the temperature of the surface to be insulated, with allowance for temperatures in excess of design conditions. The location of the insulation should also be considered, in terms of the surrounding environment, resistance to physical abuse, and required form of the insulation. The cost of the insulation is also important -- not only the initial cost, but also the maintenance cost.

There are a number of methods available for calculating the economic thickness of insulation. This involves the determination of the optimal insulation thickness providing the best trade-off between increased savings and increased costs. These methods are detailed in the following references:

- Economic Thickness of Industrial Insulation, Conservation Paper No. 46, 1976. Available from U.S. Government Printing Office, Washington, DC 20402 (stock number 041-018-00115-8).

- The Economic Thickness of Insulation for Hot Pipes, Fuel Efficiency Booklet No. 8, 1977. Available from U.K. Department of Energy Library, Thames House South, Millbank, London SW1P 4QJ, United Kingdom.

In addition, a computer program for determining the economic thickness of insulation is available from Thermal Insulation Manufacturers Association, 7 Kirby Plaza, Mount Kisco, NY 10549.

Insulation costs vary with the type of insulation used and the labor used to install it. Labor rates can represent up to 70 percent of the total installed price. Insulation of the fiberglass or mineral wood type typically costs $25 per linear meter per 25 mm thickness to install in the United States. Because insulation can reduce heat losses significantly, simple payback periods for pipework insulation are 1 year or less.

Pressure Reduction

Steam generation pressures are often dictated by the highest pressure requirements of the plant. Boiler manufacturers specify generation pressures below which their boilers should not be operated. Boiler operation below the minimum pressure stipulated will release water droplets at the surface of the boiler water and generate wet steam. To avoid such a situation, the energy auditor may wish to consider distribution at a higher pressure and then reduce pressure at or near the point of use. Although this approach can increase radiation losses, it provides dryer steam and allows the use of smaller steam distribution systems.

WASTE HEAT RECOVERY SYSTEMS

Waste heat recovery in industrial processes is a very important part of energy conservation. Economic reuse of waste energy from a process system improves thermal efficiency and reduces operating costs by reducing energy required.

Waste heat recovery from high-temperature heat sources often produces a project that is both technically and economically viable. Waste heat recovery from low-temperature sources (e.g., gas and liquid streams of 200°C and lower) is often more difficult.

The formula for heat transfer is as follows:

$$Q = (U)(A)(dt)$$

where Q = quantity of heat transferred
U = coefficient of heat transfer
A = area of heat transfer surface
dt = temperature differential.

The key factors affecting rate of heat transfer are:

- Heat transfer coefficient
- Heat transfer area
- Inlet temperature difference
- Fluid flow and velocity.

The coefficient of heat transfer (U) is very complex. It is determined by the nature of the heat transfer material, types of fluid flow, and velocity of fluid flow. Cleanliness of heat transfer surfaces is also very important, as this affects surface film, coefficients, and the overall efficiency of heat transfer.

The larger the surface area (A) of the heat exchanger, the more heat is transferred. However, this can lead to oversized and heavy heat exchanger units with increased purchase costs.

The temperature differential (dt) is the "average" difference in temperatures between the waste fluid and recovered heat source. Temperature differentials usually involve consideration of four individual temperatures:

t_1 = waste fluid into heat exchanger
t_2 = waste fluid out of heat exchanger
t_3 = heat recovery fluid in
t_4 = heat recovery fluid out.

Direction of fluid flow through the heat exchanger is of importance. Heat recovery fluid flow in an opposite direction to the flow of the waste fluid is termed "contra-flow" and usually increases the thermal efficiency of heat recovery. The greater the value of temperature differential, the greater the quantity of recovered heat. Also, the temperature of the recovered heat will be higher and of more economic use in the process. Similarly, heat transfer is increased when the fluids flow at higher velocities.

Types of Heat Exchangers

Three basic types of heat exchangers used for waste heat recovery are (see Exhibit 14.8):

- Recuperators
- Regenerators
- Liquid runaround.

These are discussed below.

Recuperators transfer heat through a wall and are usually in the form of a shell and tube, plate, or coil. An example is shown in Exhibit 14.9, where exhaust air from a drying cabinet passes through an extended surface plate heater to condition the outside make-up air.

Regenerators are used predominantly in the glass industry to store heat on a cyclical basis. They consist of two large brick-filled chambers. Flue gases pass through one of the chambers while fresh air is being drawn through the other chamber in the opposite

Exhibit 14.8

TYPES OF HEAT EXCHANGERS

RECUPERATORS

Heat is Transferred Through a Wall.

Parallel Flow Cross Flow Counter Flow	Shell and Tube

Example: Home Furnace, Gas Water Heater, Boiler

REGENERATORS

Heat is Transferred by a Mechanical Media

Parallel Flow Counter Flow	Wheel Fixed Bed - Flip Flop

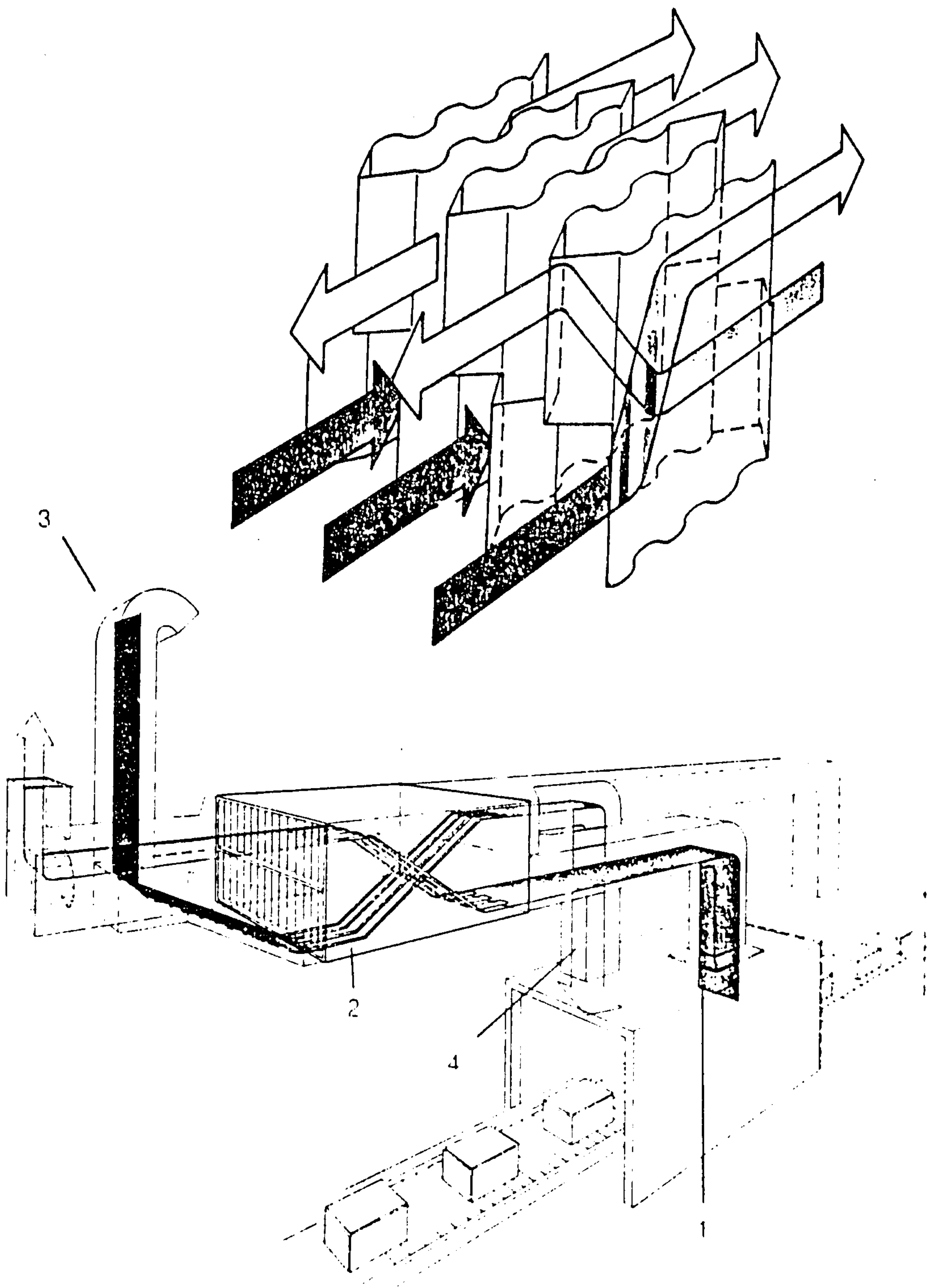
LIQUID RUN AROUND

Uses a Liquid to Transfer Heat from One Location to Another.

Example: Air Conditioning, Hot Water Heat

Exhibit 14.9

PROCESS HEAT EXCHANGER



direction. After a predetermined time, reversing valves are operated and the roles of the chambers are reversed.

Regenerators have advantages in high-temperature heat recovery over recuperators, as they are simpler in construction, capable of handling high temperatures, and give high preheats. They are generally more sturdy than recuperators.

Regenerators are capable of high rates of heat recovery, in excess of 50 percent of the heat content of the exhaust gases. It is impossible to predict costs for retrofit of an existing furnace because regenerators often must be custom-designed to match the operating characteristics of existing furnaces.

Other types of regenerators exist. Rotating heat wheels store heat in the material structure of the exchanger. In the example shown in Exhibit 14.10, the heat wheel is used to precondition makeup air for a space conditioning system. Heat wheels usually recover only the "sensible" waste heat, and the material structure of the heat exchanger is metal. Some special types of heat wheels -- called "enthalpy wheels" -- with liquid-absorbent material will recover both sensible and latent heat. Heat wheels can be used on a number of units such as ovens, kilns, and dryers. A ceramics company installed a unit on the preheating zone of a tunnel kiln where 7,000 m^3/hour of hot gas at 300°C were being rejected. The heat wheel recovers 55 percent of the heat, which is then used to preheat air for the kiln. The capital cost was recovered in less than 12 months.

All rotary type heat exchangers are fitted with seals to prevent cross-contamination of the gas streams. However, a small level of leakage can often occur.

An alternative type of regenerator uses the "heat pipe" system. The pipe contains thermal capilllary material that transfers heat from the higher temperature to the lower temperature. The outside surface of the pipe may be either plain or extended (finned) and can be made of stainless steel for use in the food industry. Heat transfer can be from and to gases, liquids, or solids. An example is shown in Exhibit 14.11. Heat pipes offer energy savings of similar magnitude to those of heat wheels, with slightly lower capital costs.

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Exhibit 14.10

HEAT WHEEL SYSTEM

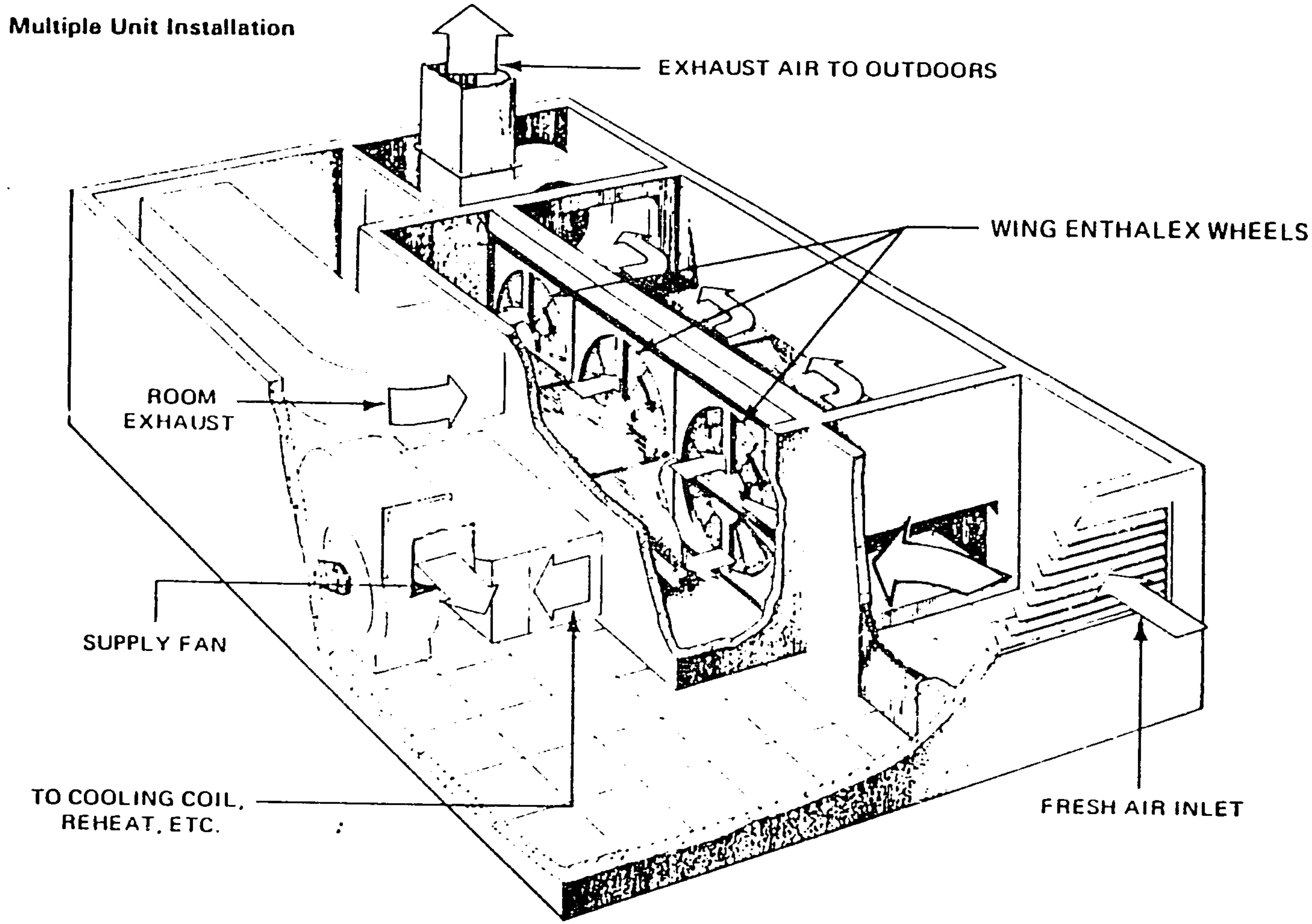

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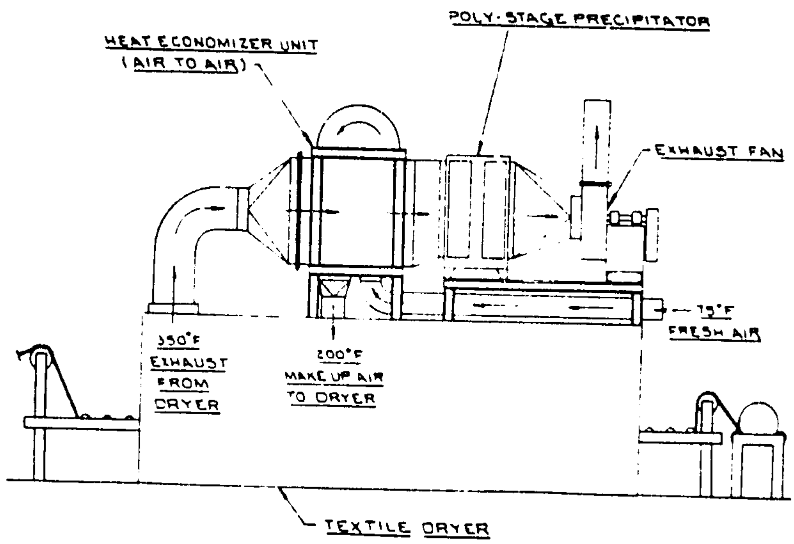
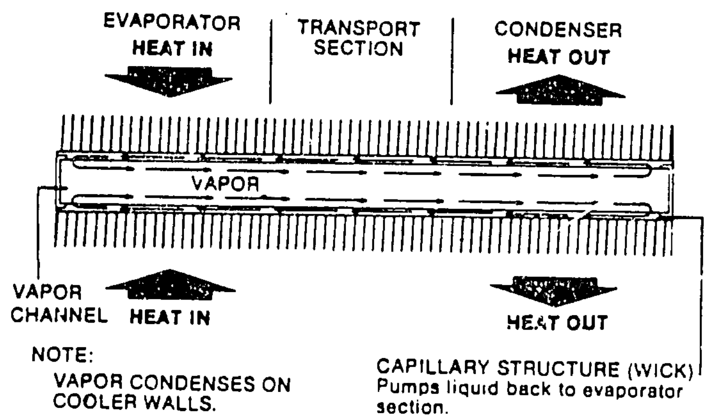
Exhibit 14.11



Tube-type exchanger and electrostatic precipitator.



Tube-type heat exchanger.

Liquid runaround recovery systems are used to gather waste heat from exhaust streams that cannot be directly reused. The system usually consists of a pair of heat exchange coils interconnected by a pipe network. Typically, a solution of ethyl glycol and water is pumped around the system and used as the heat transport medium, but for special applications (e.g., waste heat streams with temperatures in excess of 200°C), alternative thermal fluids may be used. Although used primarily to recover heat from one stream, this type of system can be used to recover heat from a series of waste heat sources and used to preheat several heat sinks. A liquid runaround system using a heat transport fluid with good thermal properties can make it economically viable to use heat recovered from a remote location.

Runaround coil system efficiencies are often in excess of 50 percent. Capital costs depend on the distance between the heat source and sink, but for a system recovering 125 GJ per year, a capital cost in the United States of about $25,000 can be recovered in 3 years.

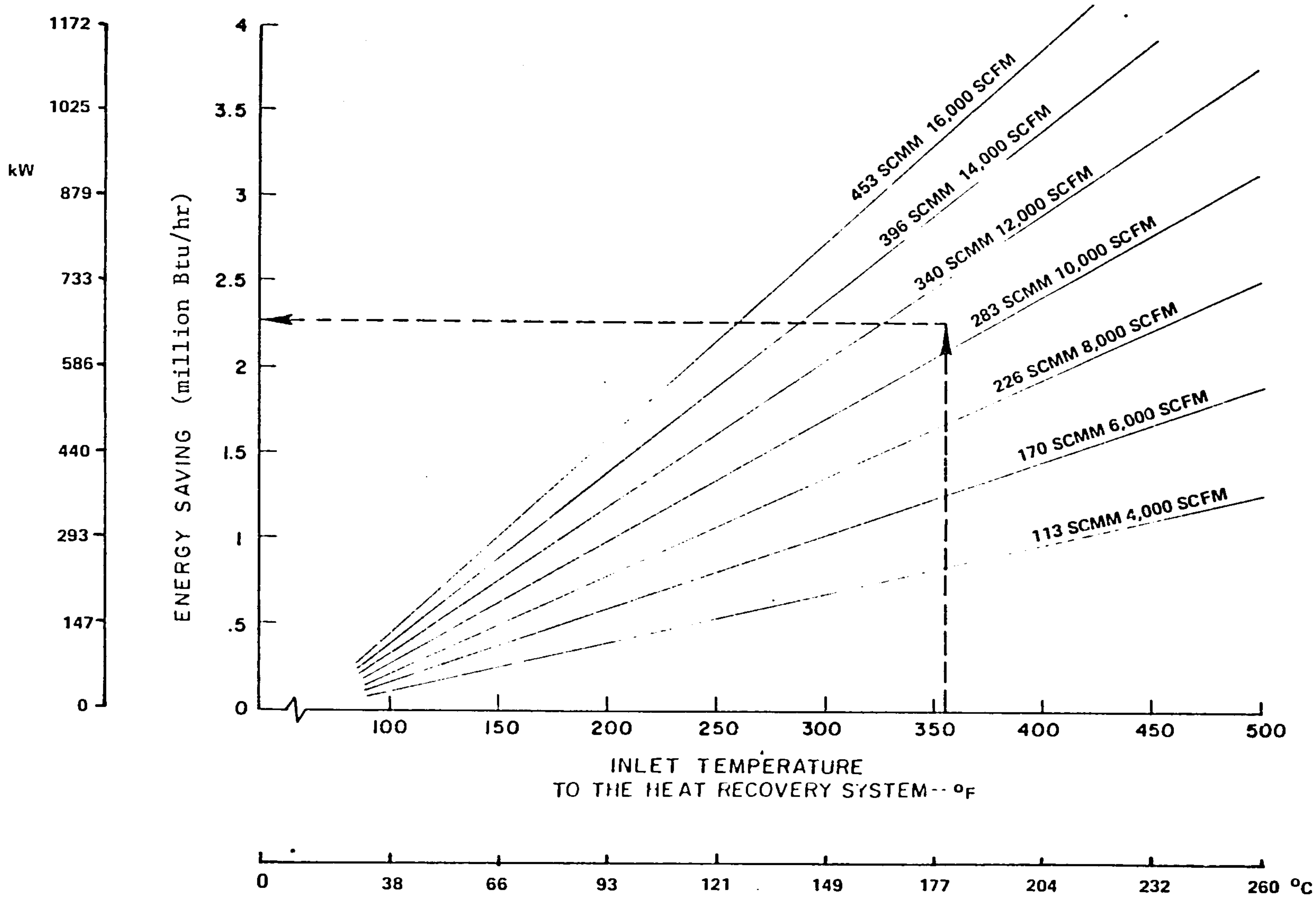
Rates of Heat Recovery

Evaluation of heat recovery rates are complex and often require technical information from the equipment manufacturer. The economics of a heat recovery project, however, are not based on the quantity of recovered heat but on the amount of savings in purchased energy that result from using the heat recovery system. This is usually called "avoided energy costs."

Examples of the variations in heat recovery are shown in Exhibit 14.12, which presents a graph of heat recovery rates compared with inlet air temperature and volumes of air flow for a specific heat exchanger. This graph shows that it is important to obtain the operating details for each specific piece of equipment.

Exhibit 14.12

ENERGY SAVINGS



Types of Heat Recovery Systems

The range and types of heat recovery systems for waste streams are extensive and cannot be discussed fully in this session. The following, however, presents a few examples of the more common simple systems.

Recirculation System (see Exhibit 14.13)

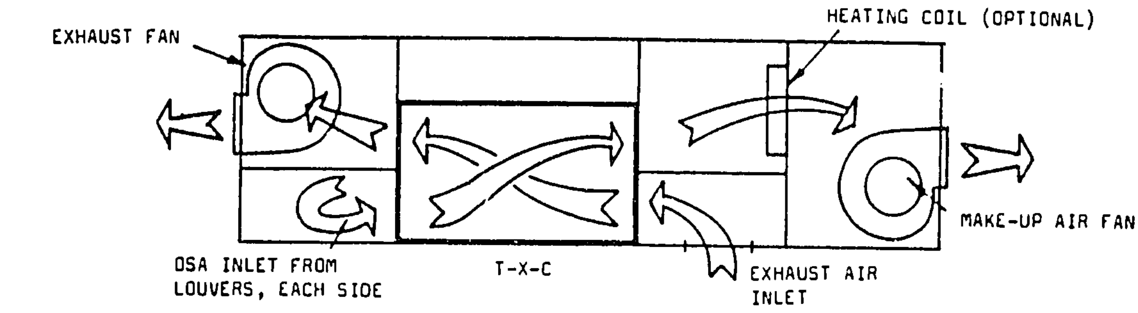
This is an example of a package heat recovery system used for the control of environmental conditions in a production plant.

1. Base unit cycle -- with 100 percent exhaust air, 100 percent makeup air, and optional heating coil. This system is not fitted with dampers.
2. Bypass cycle -- is similar to the base unit but fitted with face and bypass dampers so that the heat exchanger may be bypassed when not required.
3. Mixed air cycle -- is the same as the bypass cycle unit but operated on a mixed air cycle so that proportionate quantities of outside air are provided.
4. Recirculation cycle -- is similar to (2) and (3) except that an additional recirculation damper is provided. In this mode of operation, 100 percent of the air is recirculated, and the exhaust fan is inoperative.

Flash Steam Recovery

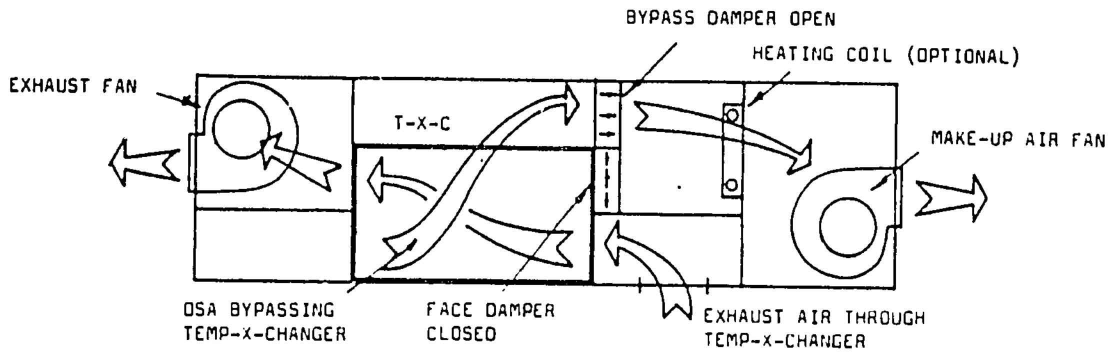
Wherever steam is used in a plant at both medium and high pressures, energy conservation potential exists through flash steam recovery. One place for potential flash steam recovery is at a boiler fitted with a continuous blowdown system. An example of a blowdown heat recovery system is shown in Exhibit 14.14. Recovered flash steam is contaminant-free and can be used for feedwater heating, feedwater de-aeration, or other process use. Blowdown heat recovery systems for boilers rated at 2.9 MW cost about $30,000 installed in the United States. Energy savings give simple paybacks around 3 years.

Exhibit 14.13



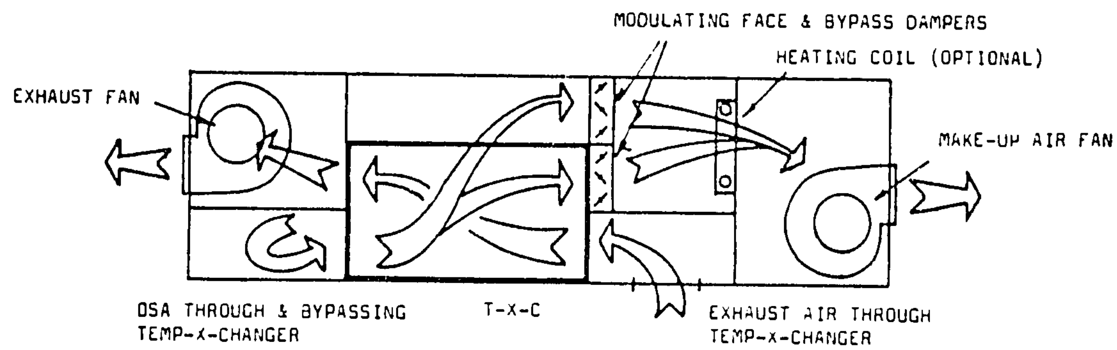
BASE UNIT CYCLE

100% EXHAUST, 100% MAKE-UP, OPTIONAL HEATING COIL
NO DAMPERS INSTALLED.



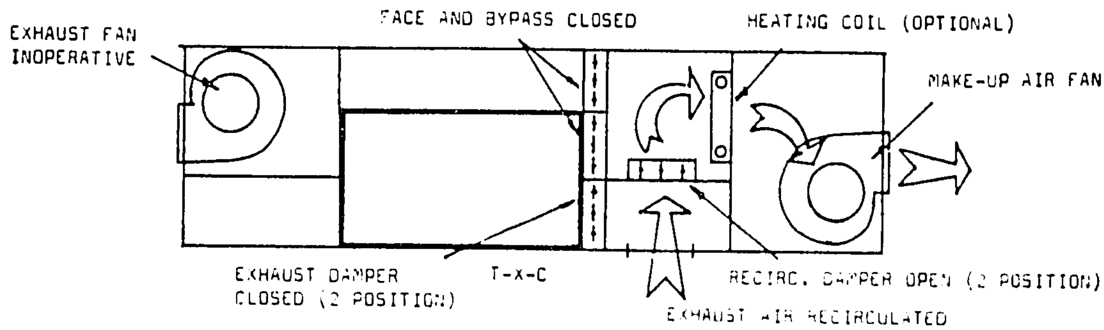
100% BYPASS CYCLE

100% EXHAUST, 100% MAKE-UP AIR BYPASSING TEMP-X-CHANGER, WHEN HEAT RECOVERY NOT DESIRED. FACE AND BYPASS DAMPERS INSTALLED.



MIXED AIR CYCLE

100% EXHAUST, PROPORTIONATE QUANTITIES OF OSA THROUGH AND BYPASSING TEMP-X-CHANGER FOR TEMPERATURE AND DEFROST CONTROL. FACE AND BYPASS DAMPERS INSTALLED.



RECIRCULATION CYCLE

UNOCCUPIED CYCLE. 100% EXHAUST RECIRC., 0% MAKE-UP FACE & BYPASS EXHAUST AND RECIRC. DAMPERS INSTALLED

Exhibit 14.14

BLOWDOWN HEAT RECOVERY SYSTEM

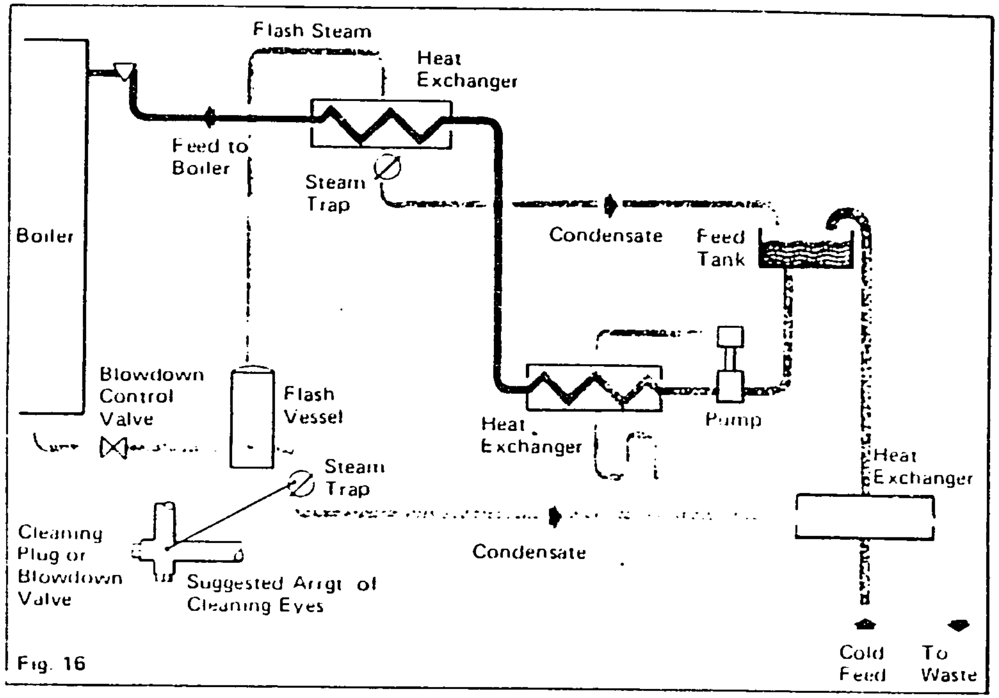


Fig. 16

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The flash steam recovery vessel used for a boiler having continuous blowdown may also be provided with an additional heat recovery coil to further cool the blowdown water after flash steam is generated. Exhibit 14.15 presents an example, and there are many variations of this type of unit.

Flash steam recovery can be used for process systems; an example is shown in Exhibit 14.16. Low-pressure flash steam is supplied to a low-pressure steam system, with additional requirements provided through a reducing valve. The system shown saved 90 kg/hr of steam and cost $6,000 to install in the United States. Savings gave a payback period of 8 months.

Maintenance

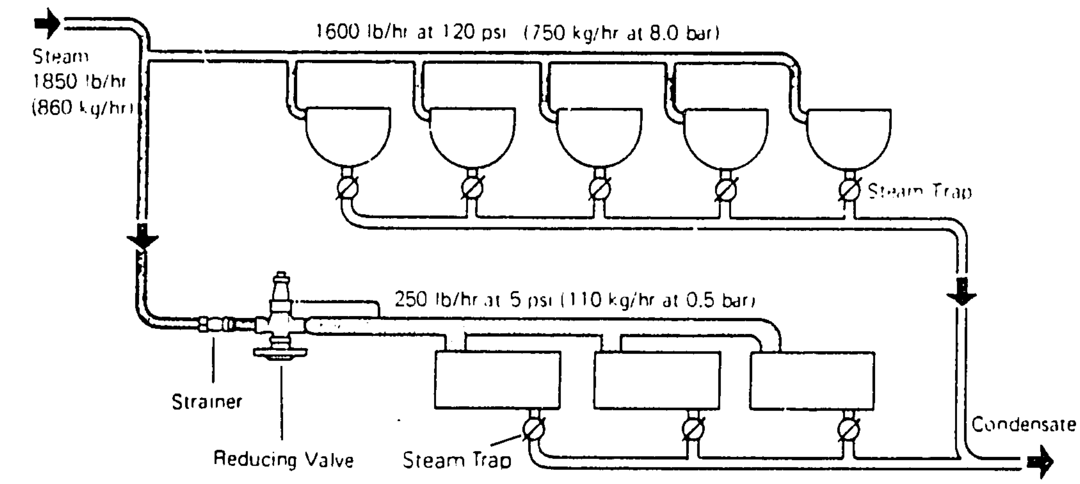
Regular maintenance of heat recovery systems is of great importance for continued high efficiency operation. Broken control systems, leaks, and dirty heat transfer surfaces can result in a significant loss in system effectiveness.

Waste heat recovery from effluent discharge of commercial laundries, textile dyeing plants, food processing effluents, and similar waste streams is very difficult. The pumping system and heat exchanger can easily be designed, but it is very difficult to filter out the contaminants in the waste stream. Particles of textile material from the laundries and dyehouses can clog the tubes and plates; grease and food particles dirty heat transfer surfaces and decrease system efficiency very quickly.

An example of automatic cleaning systems used for maintaining clean heat transfer surfaces for tubular heat exchangers and condensers is shown in Exhibit 14.17. This systype oftem is suitable only larger units, but is most effective. There are other similar automatic cleaning systems using movable devices with brushes in the tubes of heat exchangers.

Exhibit 14.15

FLASH STEAM HEAT RECOVERY



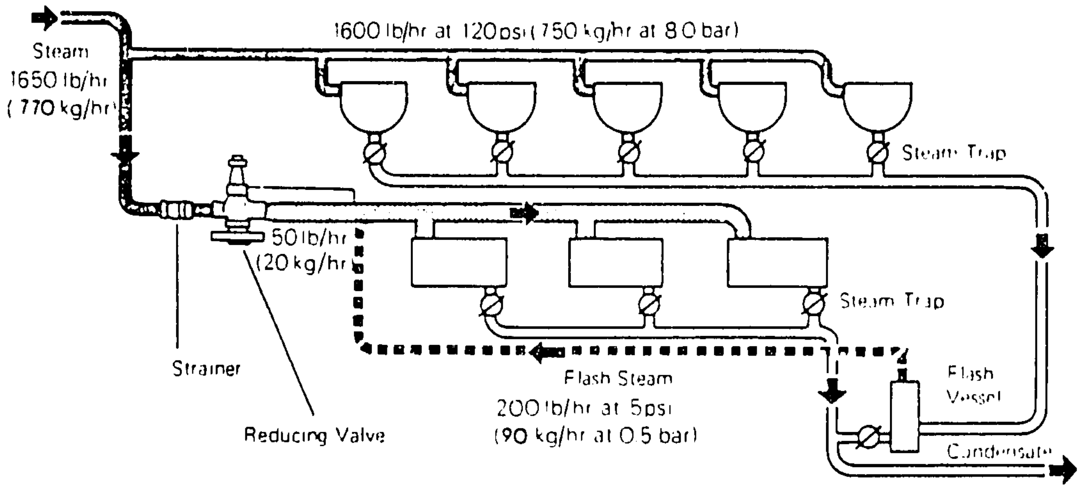


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Exhibit 14.16

FLASH ECONOMIZERS

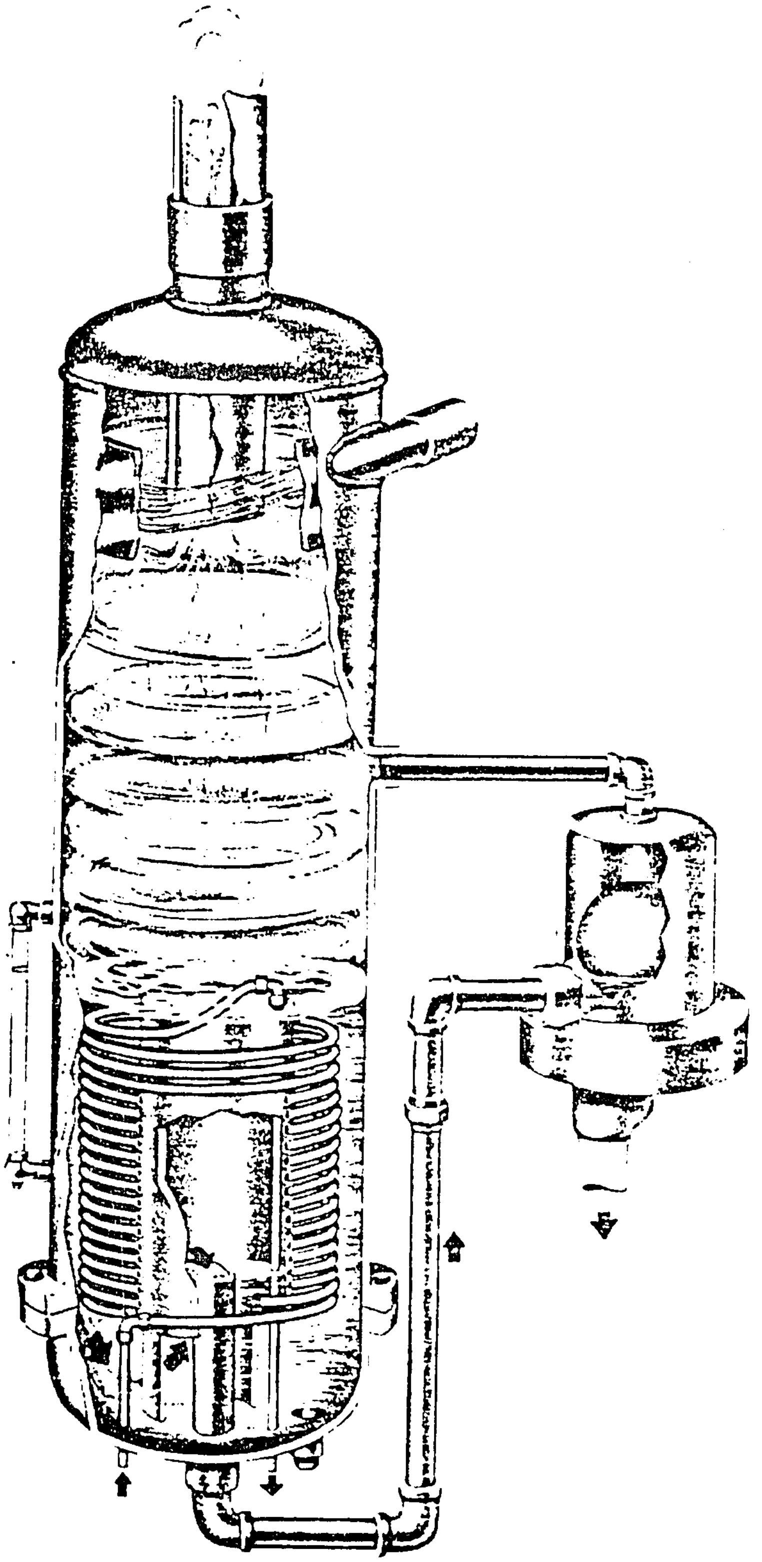

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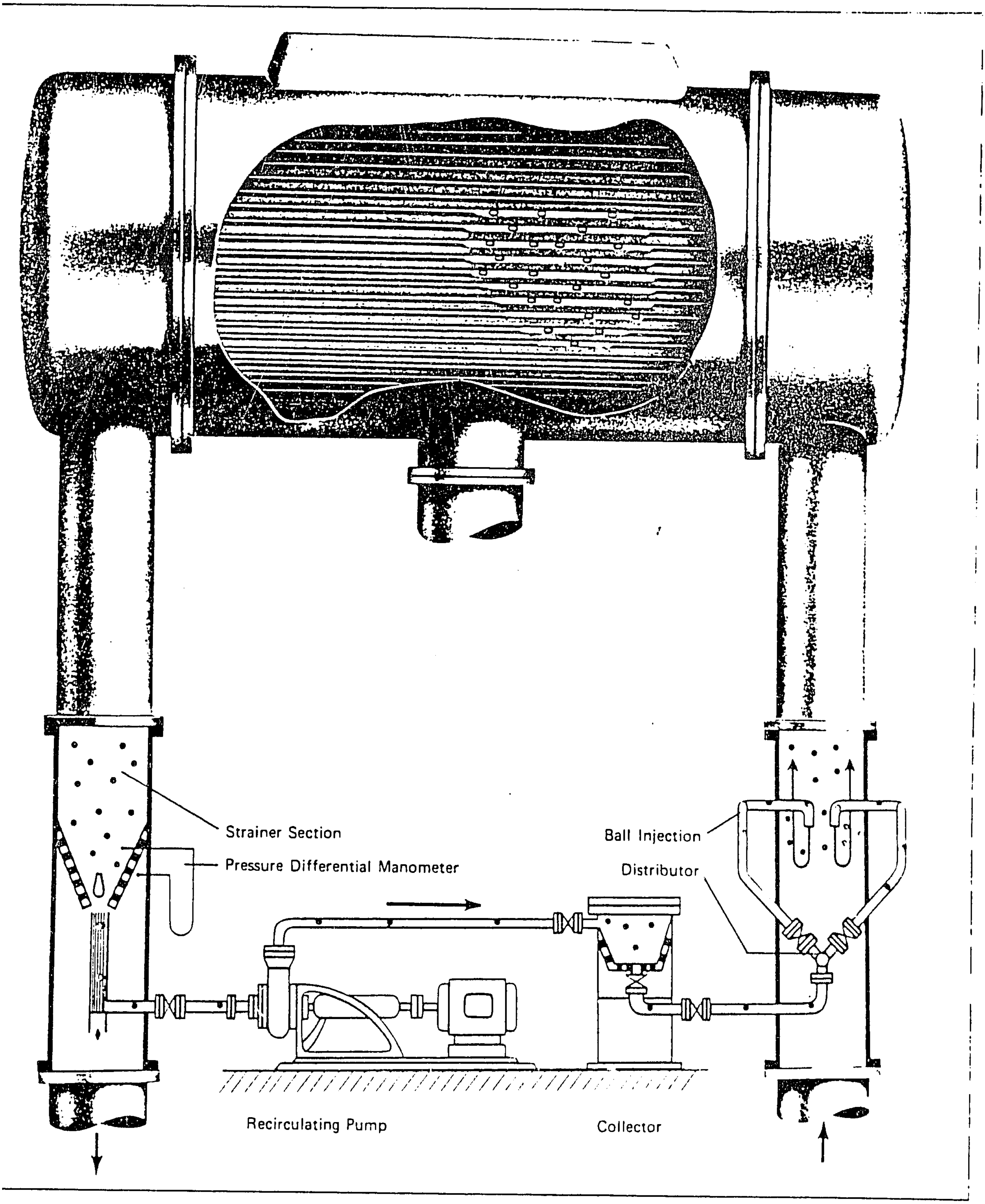
Exhibit 14.17

Automatic Cleaning System



Special Designs of Heat Exchangers

The total number of special design systems available is too great to cover in this session. The following gives a few examples of some special types.

Spiral heat exchangers (see Exhibit 14.18) are a compact type of heat exchanger with a relatively large heat transfer surface area compared to the unit's overall size. The two fluid flow in opposite directions to give maximum effectiveness of operation.

Plate heat exchangers (see Exhibit 14.19) may be designed and produced in any shape and are useful to insert into existing process vessels.

Graphite block heat exchangers (see Exhibit 14.20) are specially designed heat exchangers for use with extremely corrosive fluids. This type of unit will operate at temperatures of up to 200°C with a thermal conductivity of about 494 W/m^2K and will withstand high-pressure operation.

THERMAL FLUID HEATERS

Thermal fluid heaters are sometimes used as alternate methods of transporting heat instead of steam or hot water. Thermal fluids used are generally stable mineral oils or synthetic materials that can be heated to high temperatures. Unlike water systems, which would produce steam unless the pressure is very high, the thermal fluid systems do not vaporize and can operate at atmospheric or low pressures. Temperatures up to 500°C are readily obtainable with thermal fluids, and even higher temperatures can be reached if molten metals are used as the thermal fluid.

The main advantage to using a thermal fluid system as a high-temperature heating source is plant simplicity. Thermal fluids can be heated in standard boilers without requiring a pressurization system as with a high-temperature hot water system. Similarly, the distribution system is less complicated than a steam distribution system because there is no need for steam traps, condensate handling systems, and pressure reduction stations. Another advantage of the thermal fluid system is that there is no need for water treatment. Provided that a stable fluid is chosen, heat transfer surfaces in the

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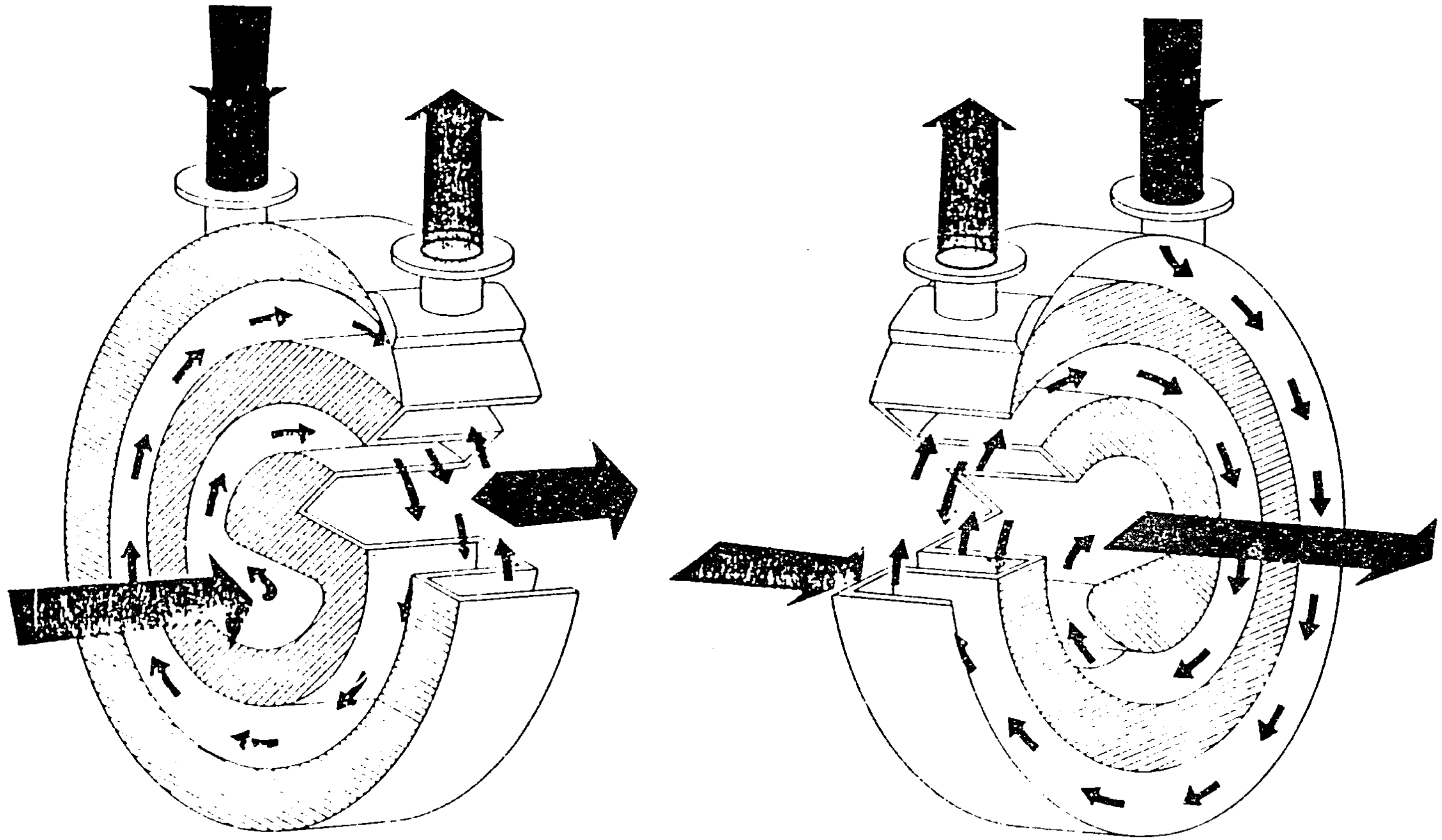
Exhibit 14.18

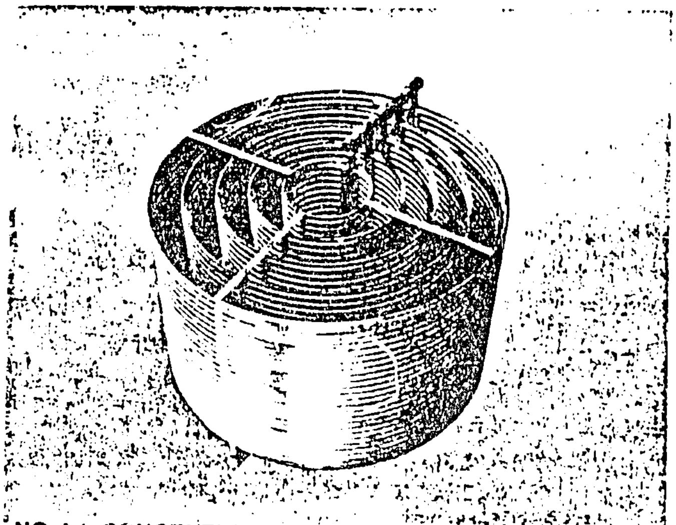
SPIRAL HEAT EXCHANGER



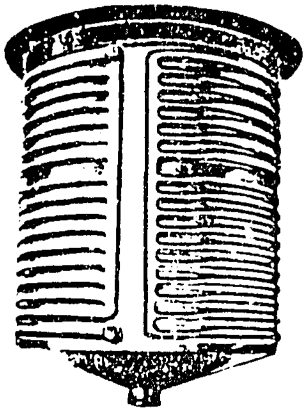
HERE'S HOW IT WORKS: The hot fluid enters at the center of the unit and flows from the inside outward. The cold fluid enters at the periphery and flows towards the center. Thus, true counter-flow is achieved.

Exhibit 14.19

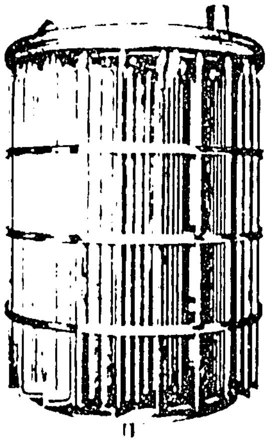
PLATE HEAT EXCHANGERS



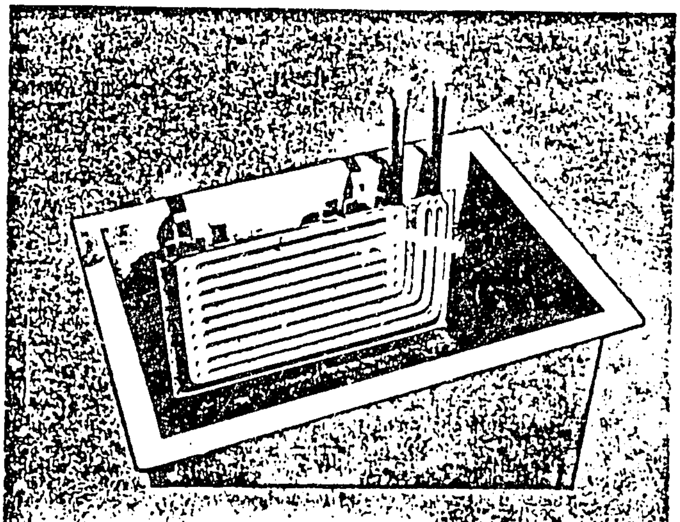
NO. 4-1 CONCENTRIC CYLINDERS



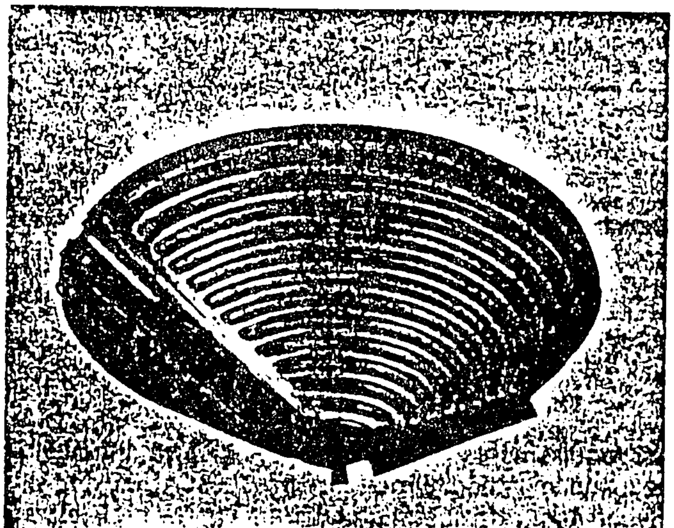
NO. 4-4 VESSEL WALLS



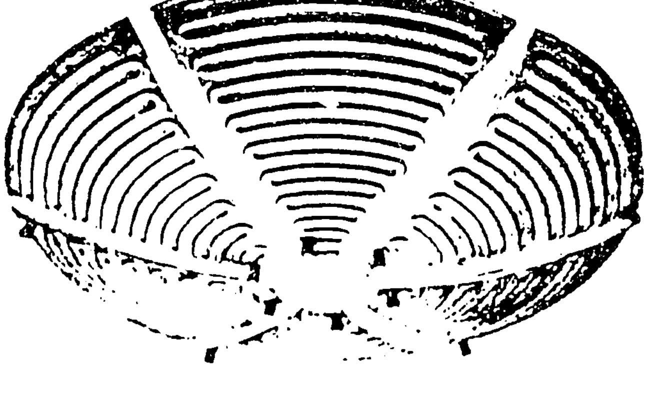
NO. 4-2 REACTOR BAFFLES



NO. 4-5 RECTANGULAR IMMERSION

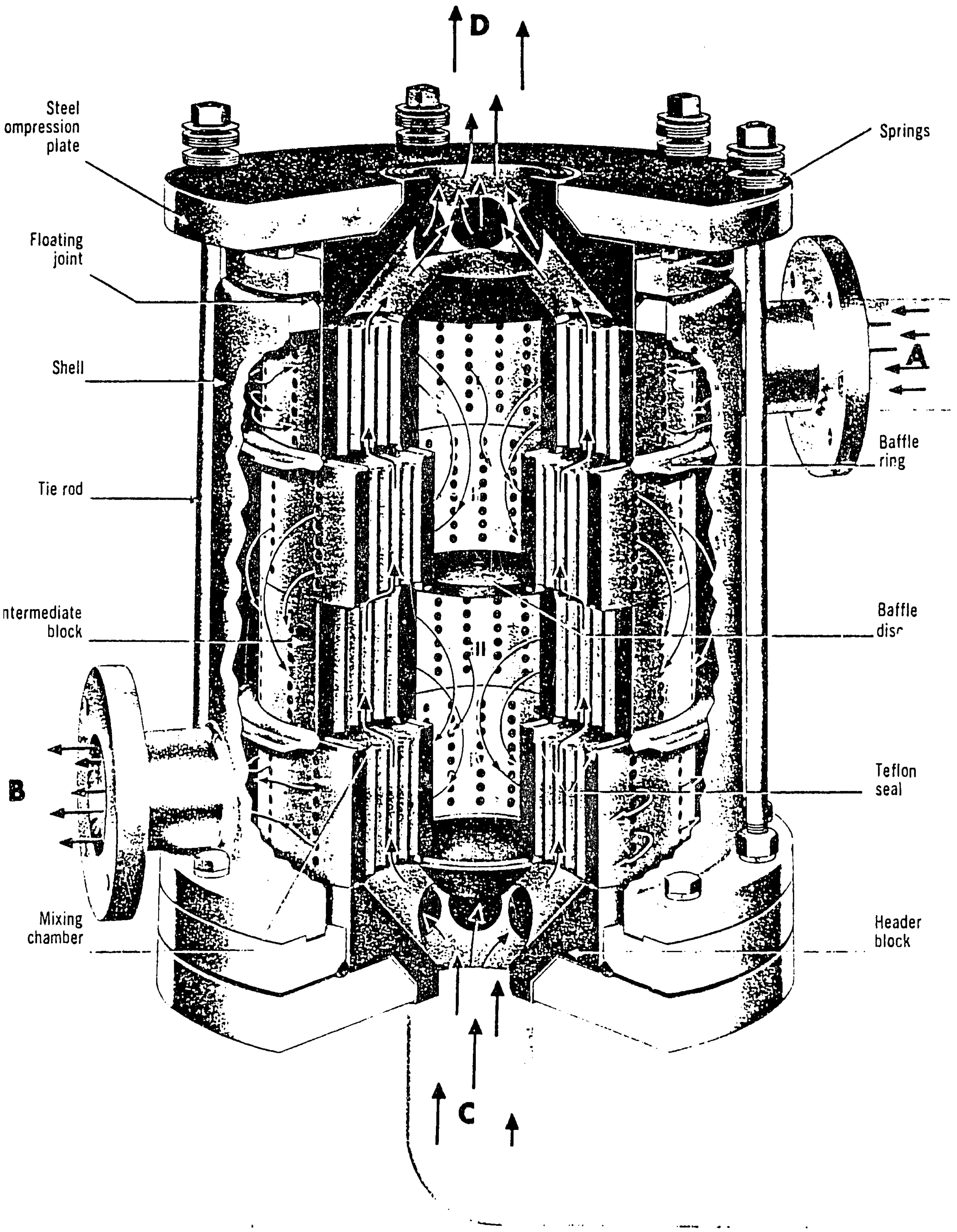


NO. 4-3 CONICAL HEADS



NO. 4-6 DISHED HEADS

Exhibit 14.20



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boiler or heater will remain cleaner, and there will be no blowdown heat loss. Thermal fluid systems usually have rapid heating characteristics, and so they offer reduced start-up time compared to comparably-sized water-based plants.

Although thermal fluid systems can be used only for indirect heating, they can have high thermal efficiencies on a par with direct-fired tank heaters.

Another disadvantage of thermal fluid systems is that they are subject to thermal degradation. Degradation is related to the formation of high boiling point polymers, and their formation alters the operating characteristics of the thermal fluid in two ways. First, it reduces the heat transfer coefficient. A 10-percent degradation will cut the heat transfer coefficient in half, which in turn (for the same heater duty) will double the film temperature gradient across heat transfer tubes and hence reduce the heat transfer rate to the process.

Second, at higher levels of degradation, the thermal fluid may begin to foul surfaces, including heat transfer surfaces, as heavier polymers are insoluble. Heat exchange systems lose their efficiency, and pump seals become prone to failure. Control valves and instrumentation may not function correctly. All of these problems would mean possible loss of production output and increased maintenance costs, together with risk for highly fouled surfaces or eventual heat transfer tube failure.

It is necessary, therefore, to select fluids correctly for thermal systems. When considering the use of thermal fluids, it is recommended to consult reputable manufacturers who can specify the correct thermal fluid for the proposed duty.

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SESSION 15: COAL CONVERSION

This session presents the different types of coal and combustion equipment that can be used by industry. Because conversion to coal of existing facilities and new coal-fired plant construction have much in common, the discussion will focus on new and replacement applications rather than retrofitting of existing oil- and gas-designed equipment. This session will cover the following topics:

- Coal classification
- Coal preparation
- Coal handling and storage
- Coal combustion technologies
- Economics of coal in industrial equipment.

Coal is defined as a "solid, brittle, more or less distinctly stratified, combustible, carbonaceous rock." From a chemical standpoint, coal is a heterogeneous material containing organic and material matter. The organic matter is composed primarily of **carbon** and small amounts of hydrogen, nitrogen, oxygen, and sulfur. The mineral matter consists chiefly of clay minerals, mineral forms of sulfur (mostly pyrite), calcite, and smaller amounts of other minerals. The percentage content of organic matter is used to distinguish coal from peat, graphite, and other carbon-bearing rocks. To be classified as coal, the "rock" must contain more than 50 percent (by weight) carbonaceous material. Below, we discuss coal classification and sulfur in coal.

COAL CLASSIFICATION

Of the various existing coal classifications, the one generally accepted is the rank classification developed by the American Society for Testing and Materials (ASTM), which is based on the degree of metamorphism (also called "coalification") of the parent plant material.

Calculated on a moist, mineral-matter-free (MMF) basis, fixed carbon content and calorific value are the standard criteria for ranking by the ASTM method, although agglomerating (caking) characteristics and percentage volatility are also considered. The mineral matter is excluded from the analysis because it does not reflect the degree of metamorphism of the coal; however, bed (equilibrium) moisture is included.

Coals that have heating values of 32,512 MJ/tonne or more on a moist basis or contain 69 percent or more fixed carbon on a dry basis are all ranked by fixed carbon, regardless of their heating values. All other coals are ranked by calorific value on a moist basis. "Moist" in this context means the coal's inherent (bed or seam) moisture, not visible water on the coal's surface. The major types of coal are described below.

Anthracite coal is coal of the highest metamorphic rank, in which the fixed carbon content is between 92 and 98 percent. It is hard and black, and has a semimetallic luster and semiconchoidal fracture. Anthracite ignites with difficulty and burns with a short, blue flame and without smoke. Anthracite coal is also known as hard coal, stone coal, kilkenny coal, and black coal.

Semianthracite coal is coal having a fixed carbon content of between 86 and 92 percent. It is between bituminous coal and anthracite coal in metamorphic rank, although its physical properties more closely resemble those of anthracite.

Semibituminous coal is coal that ranks between bituminous coal and semianthracite. It is harder and more brittle than bituminous coal, has a high fuel ratio, and burns without smoke. Semibituminous coal is also known as metabituminous coal, which is defined as containing 89 to 91.2 percent carbon, analyzed on a dry, ash-free basis. The term smokeless coal also is used.

Bituminous coal is coal that ranks between subbituminous and semibituminous coal and contains 15-20 percent volatile matter. It is dark brown to black in color and burns with a smoky flame. Bituminous coal is the most abundant rank of coal and is commonly carboniferous in age. It is also called soft coal.

Subbituminous coal is a black, intermediate-rank coal between lignite and bituminous coals, in some classifications the equivalent of black lignite. It is distinguished from lignite by higher carbon and lower moisture content. Further classification of subbituminous coal is made on the basis of calorific value.

- **Subbituminous A coal** is a type of subbituminous coal having 24,382 or more, but less than 32,512 MJ per tonne.
- **Subbituminous B coal** is a type of subbituminous coal having 22,070 or more, but less than 24,382 MJ per tonne.
- **Subbituminous C coal** is a type of subbituminous coal having 19,274 or more, but less than 22,070 MJ per tonne.

Lignite coal. A brownish-black coal that is intermediate in coalification between peat and subbituminous coal.

An easy way to represent the major properties of the various coals is shown in Exhibit 15.1, where each category of coal is characterized by its heating value and its moisture, volatile matter, and fixed carbon content.

Sulfur in Coal

A special emphasis must now be put on the content of one particular element, sulfur, whose partial removal is a major objective of coal preparation. Sulfur in coal occurs in three forms: organic, sulfate, and pyritic.

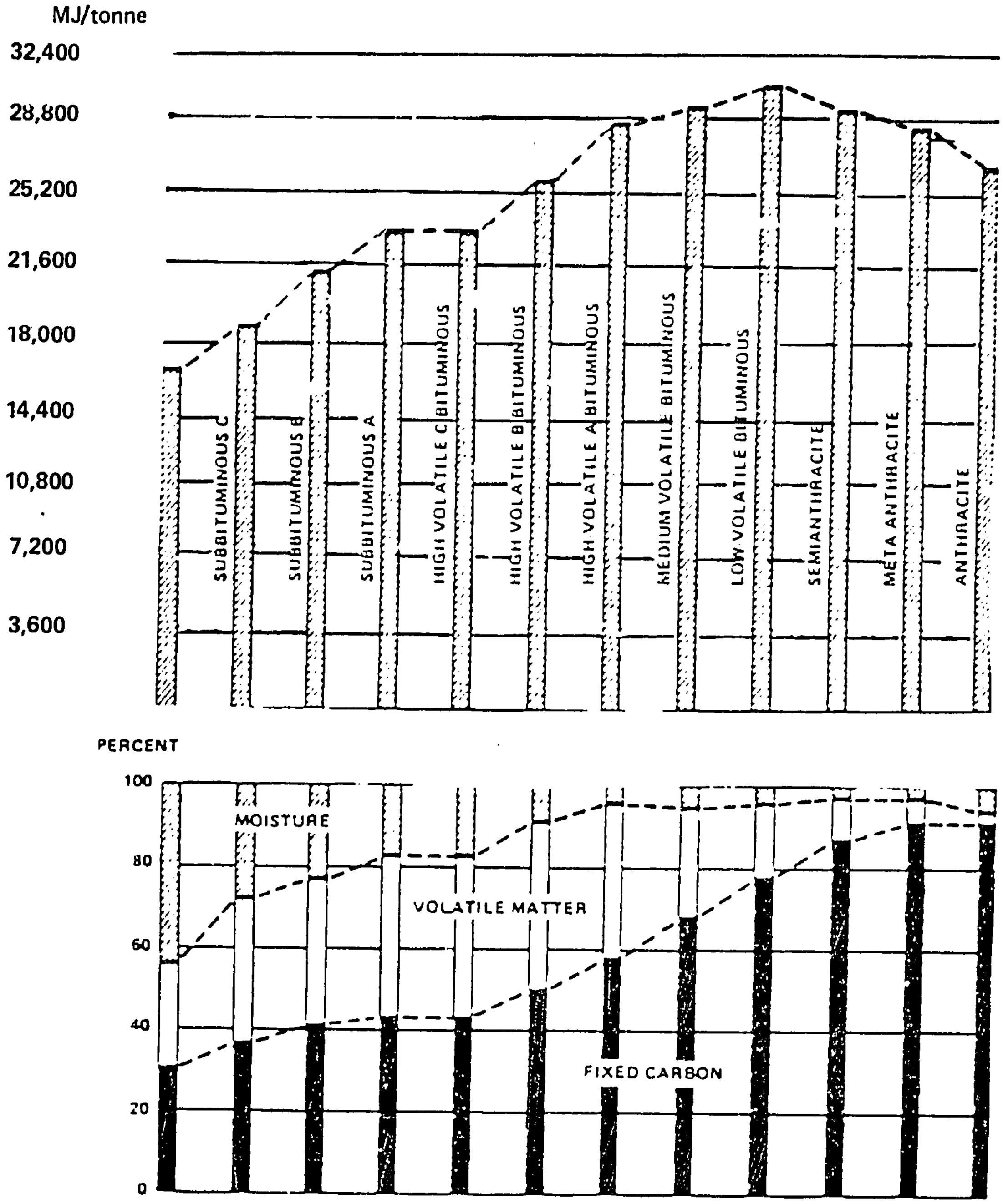
Organic sulfur, which is an integral part of the coal matrix and generally cannot be removed by direct physical separation, comprises 30-70 percent of the coal's total sulfur content. The sulfate content normally is a water-soluble oxidation product that can be removed readily during coal washing. Sulfate sulfur contents are usually less than 0.05 percent in fresh coal and thus negligible. Pyritic sulfur is the mineral pyrite, which occurs in coal as discrete particles although often of microscopic size. This sulfur can be physically removed through coal washing.

COAL PREPARATION

Coal preparation, or the upgrading of coal from the mine for subsequent use, influences the heating values and physical characteristics of coal through crushing and screening, physical cleaning, and chemical cleaning. Drying and possibly blending may also be

Exhibit 15.1

Coal Characteristics by Rank



SOURCE: Hagler, Bailly & Company, adapted from DOE, TRW. "International coal technology summary document," Dec. 1978.

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required. The various stages of coal preparation are most often categorized according to five levels. These levels, described in Exhibit 15.2, range from breakage without cleaning to multistage, rigorous cleaning and drying. Depending on the degree of preparation and the nature of the raw coal, cleaning processes generally produce a uniformly sized product, remove excess moisture, reduce the sulfur and ash content, and increase the heating value of the coal. Preparation phases are described below.

Crushing and Screening

After extraction from the mine, most coal must be crushed before use or sale, usually at the mine site. Primary crushing releases large particles of impurities such as clay, rock, and pyrite, and removes extraneous material that becomes mixed with coal during mining and transportation. The screening process sizes the coal for different marketing purposes and efficient cleaning. Further crushing and sizing will often take place at the plant site to tailor the coal to the combustion or conversion process.

Physical Cleaning

Physical coal cleaning removes impurities such as pyrite, ash, and rock from coal by a mechanical separation process based on a gravity difference between the lighter coal and heavier contaminants. The need for physical cleaning is determined by four major considerations: purpose of cleaning, air pollution regulations, cost of cleaning, and alternatives to cleaning. Several of these considerations ultimately depend on the characteristics of the coal. For example, physical cleaning removes only pyritic sulfur. If the coal is low in total sulfur content, the removal of pyritic sulfur may be so insignificant as to not justify the cost of physical cleaning. If the coal is high in total sulfur content, the thorough physical cleaning process may significantly reduce coal yield and render the process unwarranted.

Exhibit 15.2

Levels of Coal Preparation

Level & brief designation	Process description	% weight yield	% heat recovery	Reduction potential: Ash	Reduction potential: Sulfur	Typical circuits & equipment used (incremental over previous level)	Application
1. Breaking	Breakage for top size control to 76.2 mm, with removal of coarse refuse.	98-100	100	None to minor	None	Scalping screen, crusher, rotary breaker	Applied to run-of-mine coal.
2. Coarse	Fractions of coal larger than 9.5 mm are treated; smaller particles are not cleaned clean but shipped together with treated material.	75-85	90-95	Fair to good	None to minor	Vibrating screens, jigs, heavy-media vessels or cyclone, dewatering, thickeners, filters	Used where small coal particles (less than 9.5 mm) are fairly or when rocks larger than 9.5 mm are present to a large degree.
3. Deliberate (fine and coarse)	Wetting of fine and coarse size coal particles. Coal particles larger than 28 mesh are cleaned; smaller particles are dewatered and either shipped with clean coal or discarded as refuse.	60-80	80-90	Good	Fair	Concentrating tables or hydroclones; some thermal drying	Used with coals having good washability characteristics.
4. Elaborate (very fine)	All coal feed is wetted and washed. Thermal drying used for coal smaller than 6.3 mm mesh to limit moisture content.	60-80	80-90	Good to excellent	Fair to good	Flotation circuits; thermal drying prevalent	Used with coals have excellent washability characteristics.
5. Full	Rigorous beneficiation. Coal is crushed to much finer sizes than in other levels. The coal undergoes multistage cleaning with various products and is separated into two streams: clean coal and middlings.	60-80	85-95	Clean coal stream: Excellent Middling stream: None to fair	Excellent None to fair	Additional size reduction	Used to obtain two or more washed coal products of differing qualities.

SOURCE: Coal in America, An Encyclopedia of Reserves, Production and Use, Richard A. Schmidt, 1979; "Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal," U.S. Environmental Protection Agency, December 1979.

Chemical Cleaning

Chemical cleaning is a new technology being developed to remove higher percentages of sulfur from the increasing proportions of high-sulfur coals. The technique removes most, if not all, pyritic sulfur and mineral contaminants, while some processes remove varying amounts of organic sulfur by treating the coal either in acidic or basic solutions or with selected gases.

COAL HANDLING AND STORAGE

The coal handling system involves unloading of coal deliveries, intermediate storage, and any other transfers of coal prior to combustion. Systems will vary depending on plant capacity flexibility, space limitations, available labor, and method of coal shipment.

Coal Storage

If the coal is not unloaded directly to storage, it is necessary to transfer the coal to the yard. Coal feeders remove coal from track hoppers or temporary storage piles at a controlled rate to the permanent storage site. Vibrating, belt, apron (pans equipped with site pieces), and rotary-plow feeders are types currently in use. Small plants with limited space may use screw conveyors, which are inexpensive and can be installed on an incline. Coal may be stored in open piles or in enclosed bins and silos; the design of the storage system will usually be unique to fit the consumer's needs.

Open Storage

There are two main types of open storage: conical-shaped stockpiles and wedge-shaped stockpiles.

In a conical-shaped stockpile, the base of the is formed by a doughnut-shaped dead storage area composed of coal or land. Live coal storage is filled with a crane-like conveyor through lowering wells or a telescopic chute to restrict coal dust. Small industrial

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coal-handling systems can use a bucket elevator for stacking. A belt feeder first moves coal from the under-track hopper to the bucket elevator. At the top of the elevator, the coal is dumped through a chute onto the coal pile. Underground recovery can be either through a single opening in the center of the cone's base or through a reclaim system extending the diameter of an all-coal pile. The latter system allows a more rapid withdrawal rate.

The <u>**wedge-shaped stockpile**</u> is designed for large storage capacity, from 45,000 to 100,000 tonnes or more (typical storage for a 200-400 MW powerplant). A bucket wheel stacker/reclaimer is used to form the pile and remove coal. The stacker/reclaimer operates from a conveyor running parallel to the pile, and, after building a pile to its maximum height, moves a few feet to build another pile. Reclamation is done by reversing the direction of the conveyor. A sectional view of a wedge-shaped stockpile reveals the same storage patterns as the conical pile: a trough of dead storage runs along the wedge, with live coal stacked in and above the trough. A collecting belt runs under the middle of the trough.

Covered Storage

Active coal is often kept in closed storage to prevent damage from humidity. Some silos also contain compartments for dead storage for use in emergency. Enclosed silos are also effective in limiting fugitive dust problems if the coal contains large amounts of fines.

Stackers/reclaimers, mobile equipment, or underpile hoppers are common mechanisms for reclaiming coal from storage. Stackers/reclaimers and underpile hoppers can be used with conical- or wedge-shaped storage piles, with the latter used in more complex industrial systems. Belt conveyors are again used to transfer coal from storage to the plant. This trend toward unique design has resulted from the use of coal types that vary in composition and weight. Factors influencing selection of belt conveyors include fuel flow characteristics, maximum lump size and percentage of fines, coal moisture content, and any impurities in the coal. The speed of the belt conveyor is determined by the maximum speed permissible to minimize product degradation and fugitive dust emissions. The coal is discharged at the end of the belt; however, installation of trippers allows discharge of coal along the length of the belt. When the coal is delivered to the plant, it will undergo any necessary processing prior to combustion.

COAL COMBUSTION TECHNOLOGIES

Industrial coal combustion is primarily achieved in boilers for the purpose of steam or efficient hot water generation. In addition, some industries such as the cement, steel, brick, and tile industries have technologies that rely on direct coal firing. Because not all kinds of coal can be used directly, while most of them can be burned in a boiler if adequately prepared, we will divide this section into two parts: coal combustion in boilers and direct coal combustion for individual furnaces.

Coal Combustion in Boilers

The conventional coal-fired boilers are generally classified in three types according to their firing system* (see Exhibit 15.3):

- Stoker boilers
- Pulverized-coal boilers (PCBs)
- Cyclone-firing coal boilers (CFCBs).

Nonconventional coal-fired boilers can be assimilated to atmospheric fluidized-bed boilers (AFBBs) because they are the only ones commercially demonstrated. Other types are still under research and development. The alternative technology, pressurized fluidized-bed combustion (PFBC), is more directed towards electricity generation in combined cycle plants and probably will not be commercially demonstrated before the late 1980s.

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*Another classification commonly used is based on the heat transfer. According to these classifications, there are two groups of boilers: shell or firetube, and watertube (see Sessions 4 and 11). However, this approach is not relevant to the fuel characteristics and the firing system classification is preferable.

Exhibit 15.3

Coal-Fired Boilers: Types and Major Characteristics

Type			Characteristics		
				Range of steam generation	
Category	Subcategory	Type	Types of coals	Tonnes of steam/hour	Heat release (MJ/hour)
Stoker boilers	Spreader	Stationary and dumping grate Traveling grate Vibrating grate	All except anthracite All except strongly caking bituminous All except strongly caking bituminous	Up to 200, but usually under 50	5,000/m^2 8,360/m^2 4,600/m^2
	Underfeed	Horizontal-feed (single and double retort)	Caking coals	10-15	3,450-4,800/m^2
		Gravity-feed (multiple retort)		Up to 250	5,850-6,900/m^2
	Water-cooled vibrating grate		Wide range of bituminous and lignite coals, even those with high free-swelling index	Up to (100-150)*	4,600/m^2
	Chain grate and traveling grate		Almost any solid fuel	Up to (100-125)*	5,850/m^2
Pulverized-coal boilers		Bin system Direct-firing	Almost any, but a given pulverizer can operate efficiently only on a narrow range of coals	Up to 2,000	Not applicable
Cyclone furnace		One-wall firing Opposed firing	Coals with slag viscosity below 250 poise at 1,427°C, volatile matter higher than 15 percent, and low ratios of sulfur/iron		16,270-31,350 MJ/m^3

*Estimate.

SOURCE: Hagler, Bailly & Company.

Stoker Boilers

These boilers are characterized by a continuous addition of coal through mechanical "stoking," permitting a steady combustion. The air supply is adjusted so that complete combustion can be obtained with a minimum of excess air.

However, experience shows that stoker firing is more economical for steam-generating units of capacity less than 50 tonnes of steam/hour, where the lower efficiency (compared with the other systems) can be tolerated. As shown in Exhibit 15.4, the type of coal has an influence on the choice of firing method.

Stoker types differ essentially in their fuel burning rate, which depends on the type of coal used consistent with their required characteristics (as shown in Exhibit 15.5) and the characteristics of the grates.

The major drawback of stoker boilers is the lack of flexibility in the achievable rate of steam generation when compared with pulverized-coal and cyclone-furnace-firing. On the other hand, stoker boilers have the advantage of being able to burn a wide range of solid fuels, including almost any coal, and also varying byproducts and waste fuels (paper and food industry).

Mechanical stokers can be classified in four main groups based on the method of introducing fuel to the furnace:

- Spreader stokers
- Underfeed stokers
- Water-cooled vibrating grates
- Chain grates and traveling grates.

<u>Spreader stokers</u>. The spreader stoker can burn almost any coal. It works by projecting the coal into the furnace over the fire, with a uniform spreading action permitting suspension burning of the fine fuel particles. The heaviest pieces, which cannot be supported in the gas flow, fall into the grate for combustion in a thin fast-burning bed. The major breakthrough that promoted this type of boiler feeding system was the introduction in the late 1930s of the continuous-ash-discharge traveling grate of

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Exhibit 15.4

Influence of Coal Type on Firing Method

Characteristic	Maximum content limit: Stoker	Pulverized coal	Cyclone-furnace
Total moisture (as fired), %	15-20	15	20
Volatile matter (dry basis), %	15	15	15
Total ash (dry basis), %	20	20	25
Sulfur (as fired), %	5	N/A	N/A

These limits may be exceeded for lower rank coals with a higher inherent moisture content (i.e., subbituminous and lignite).

SOURCE: Babcock & Wilcox, "Steam," 1972.

Exhibit 15.5

Maximum Allowable Fuel Burning for Stokers

Type of stoker	$MJ/m^2/hour$
Spreader:	
Stationary and dumping grate	5,000
Traveling grate	8,360
Vibrating grate	4,600
Underfeed:	
Single or double retort	4,800
Multiple retort	6,900
Water-cooled vibrating grate	4,600
Chain grate and traveling grate	5,850

the air-metering design. Another characteristic of the spreader stoker is that partial suspension burning results in a greater carryover of particulate matter in the flue gas than in other types of stoker. Cyclone-dust collectors are used to separate the fines that are discharged to the ash disposal system from the coarse that are recycled to the burner. The economics of the spreader stoker make it particularly attractive for versatile fuel burning under 200 tonnes of steam per hour (tsh).

Underfeed stoker. These stokers are of two types: type 1, horizontal-feed and ash discharge; and type 2, gravity-feed and rear-ash discharge. Underfeed stokers differ from spreader stokers primarily because in these devices, coal is not spread over the bed but fed continuously by gravity. Stokers of type 1 are usually limited to 10-15 tsh with burning rates of 5,000 $MJ/m^2/hour$ when used in single- or double-retort (central trough) and water-cooled wall furnaces. Multiple-retort devices can be used to generate up to 210 tsh and caking coals can be burned in these systems.

Water-cooled vibrating-grate stokers. These systems must not be confused with spreader stokers with air-cooled vibrating or oscillating grates. A water-cooled vibrating grate consists of a tuyere-grate surface closely mounted on a grid of water tubes interconnected with the boiler circulating system. This system is particularly suitable for high free-swelling coals such as lignite because it avoids the formation of large clinkers due to the grate vibrations. Burning rates of these stokers should not exceed 4,180 $MJ/m^2/hour$. Ash residue is very simple because ashes are automatically discharged to a basement ash pit.

Chain-grate and traveling-grate stokers. In these systems, the layer of coal fed by gravity from the hopper is heated by radiation from the furnace gases driven off by the distillation. The fuel bed continues to burn as it moves along with the grate, growing progressively thinner as combustion continues until the remaining ash is discharged into the ash pit.

Pulverized Coal Boilers (PCBs)

Pulverized-coal firing is a more recent technique than stoker firing and more effective for high rank and grade coals. These boilers require less excess air to operate, can

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generate from 50 to nearly 2,000 tsh in multi-burner devices and are found more economical in large sizes such as utility boilers. In this type of system, the coal is pulverized to about 200 mesh particle size (74 microns) and blown into the combustion chamber with 20 percent of the combustion air used for coal transport. The other 80 percent, called secondary air, is introduced at the burner.

The pulverizer and the burner are the two basic components of a PCB system. Other necessary requirements include hot air for drying the coal for effective pulverization, fans, coal feeders, and conveying lines. The direct-firing system (as opposed to the bin system) is the most widely used for processing, distributing, and burning pulverized coal because of its advantages in safety, cleanliness, and costs. Such a system is shown in Exhibit 15.6.

Coal feeding. The feeding of coal and air can be adjusted from the positioning of either primary flow to the load demand (e.g., air from coal, or vice versa).

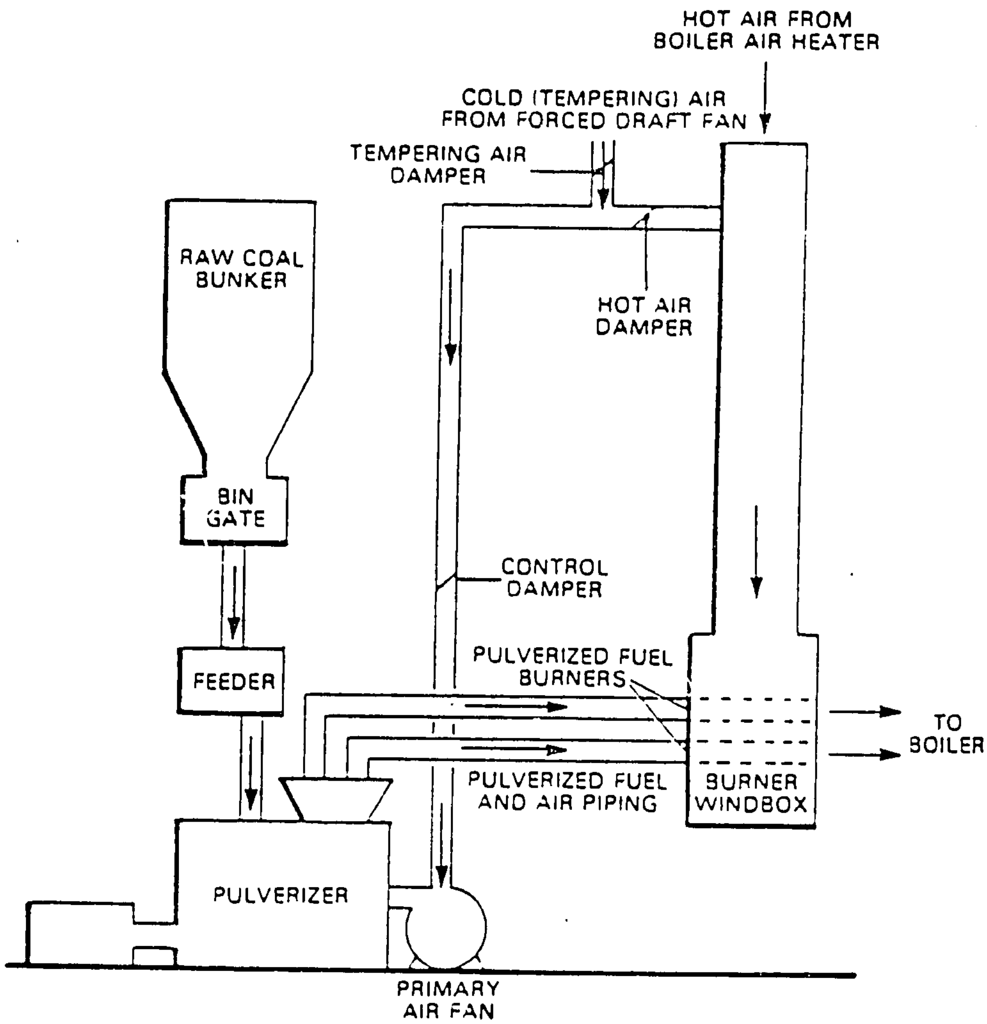
Pulverizer selection. The pulverizer design is based on several considerations, including feeding (automatic control of the proportioning), fuel drying (usually by preheated combustion air), grinding, coal circulating within the pulverizer, classifying (to recycle the inappropriate sizes), and air/coal mixture transporting.

The major type of coal pulverizers are usually classified by ranges of rotation speed (e.g., ball-and-race, roll-and-race), and their selection depends especially on the characteristics of the coal (e.g., grindability index, moisture content).

Combustion. The basics of oil combustion are applicable to pulverized coal, although the particulate sizes and the moisture content are quite different. For example, a PCB requires more excess air. When boilers are used to burn different coal qualities, the combustion optimization becomes very sophisticated, and the coordination of pulverizer and burner operation requires highly qualified operators to preserve the system efficiency. Other problems associated with pulverized-coal firing systems involve controlling fly ash slagging and emissions.

Exhibit 15.6

Pulverized-Coal Firing System



SOURCE: Energy fact book. Department of the Navy.

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Cyclone-Fired Furnaces

Cyclone-fired furnaces are the most recent conventional systems and have several advantages over stoker and pulverized-coal firing systems, including a significant reduction in the fly ash content in the flue gas, a simpler and cheaper preparation process (four-mesh screen only), a smaller furnace size, and the ability to burn lower ranks of coals and to operate at high temperatures. These attributes increase combustion efficiency.

In the cyclone-fired system (see Exhibit 15.7), crushed coal is introduced into the horizontal burner cylinder and the combustion air enters the burner tangentially along the cylinder periphery to produce a whirling pattern of coal particles. This combustion process is more rapid because of its higher turbulence. Burners are aimed downward to direct slagging ash toward the bottom of the furnace ("slagging" burners).

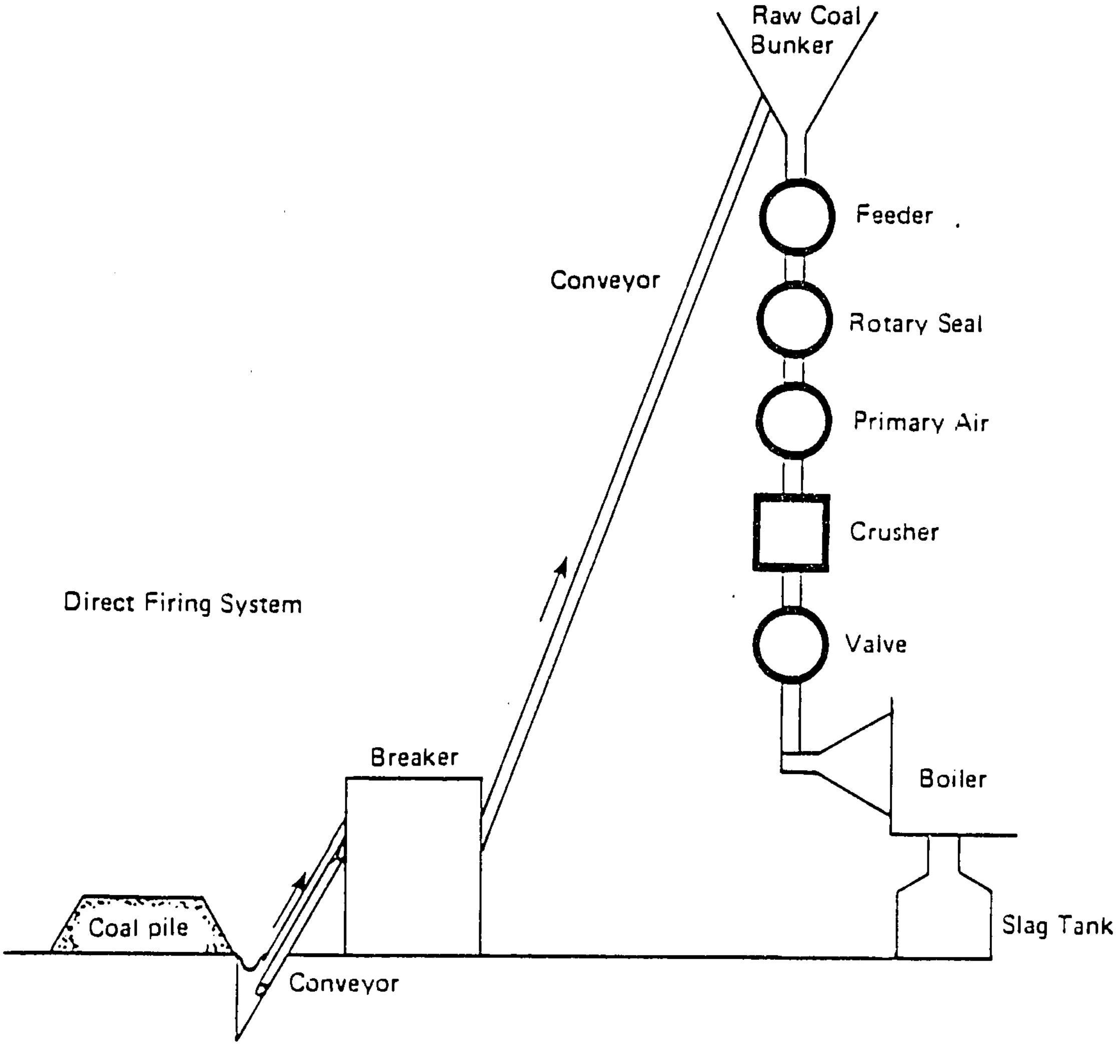
All cyclone furnaces are slag-top furnaces, meaning that because of the high temperature achieved (1,600°C), the ash accumulates in a "wet bottom" or molten slag condition. The molten slag may be either continually or intermittently withdrawn into a water tank, where it is quenched and broken into finely divided slag droplets. In a dry bottom furnace such as the pulverized-coal fired system, 70 to 90 percent of the ash is lost out the top of the furnace, with only 10 to 30 percent of the ash leaving through the ash hopper in the furnace bottom. A slag-top furnace may have 30 to 50 percent of the ash leaving through the ash hopper. A further cost benefit to this type of furnace is the normal absence of combustibles in the ash due to the molten ash phase of the process (see Exhibit 15.7).

There are two major configurations for cyclone-fired furnaces: one-wall firing for small units, and opposed firing for large units.

Atmospheric Fluidized-Bed Boilers (AFBBs)

AFBBs are currently under more intense development because this type of combustion offers the potential for efficiently using high-sulfur coal.

Exhibit 15.7
Cyclone Fired Systems



SOURCE. Hagler, Bailly & Company.

Note. In a bin system, the crusher is located just after the breaker instead of after the primary air.

In an AFBB, pulverized coal is injected with its transport air through a "bed" of non-combustible material (inert ash and limestone or dolomite), which is held in suspension or "fluidized" by the uniform injection of air through the bottom of the bed at controlled rates. Most sulfurs react with bed materials, forming a dry calcium sulfite solid, instead of being emitted into the atmosphere.

Because AFBBs can burn a wide range of solid fuels, economics are likely to favor them in a world of uncertain fuel prices and availability. According to the U.S. Department of Energy (DOE), AFBB capital costs are expected to be 15 percent below those for alternative conventional coal-fired steam generators with a scrubber. If no scrubber is required, however, conventional boilers are cheaper than AFBBs. Some manufacturers claim a difference of as much as 25 percent. Furthermore, steam production costs may be as much as 10 percent less than conventional units burning the same fuel. Above all, burning high-sulfur fuel can reduce fuel costs up to 50 percent and more when compared with oil and gas at current prices.

State-of-the-art. Several projects are currently in operation or under demonstration. Although there are still many unanswered questions regarding large-scale applications of AFBBs, the technology is believed to be on the verge of commercialization for industrial-scale operations. However, the major barrier to the system's acceptance is its yet-unproven performance under conditions representative of industrial plants.

The most relevant and documented experience is undoubtedly the operation of the Foster-Wheeler-Pope, Evans & Robbins boiler at Georgetown University in Washington, DC (United States). The 45 tonnes/hour boiler, developed with DOE assistance, is designed to burn high-sulfur coal for space heating and cooling applications with saturated steam (see Exhibit 15.8).

Direct Coal Combustion

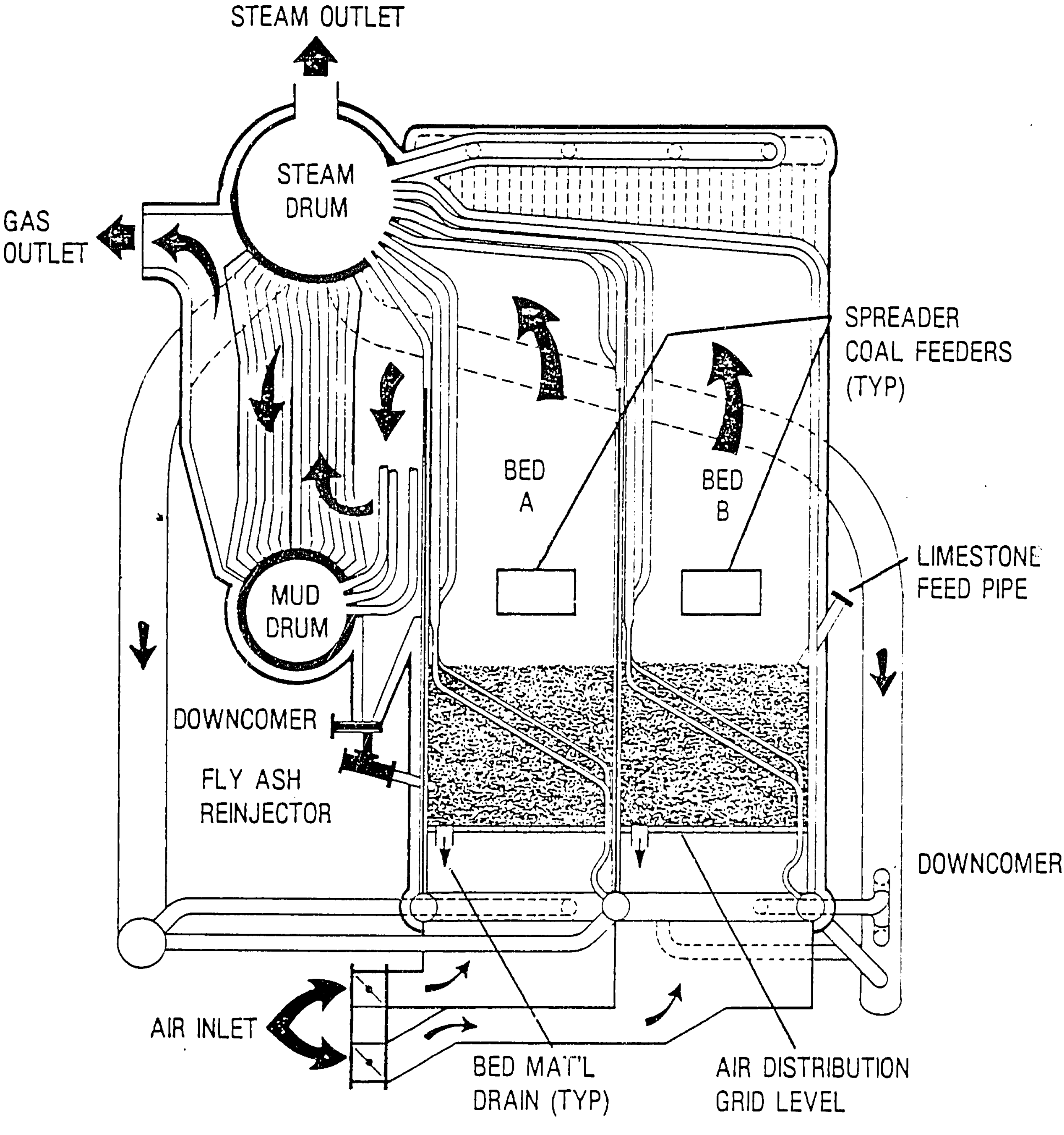
All firing systems described above can be used for direct combustion. In direct combustion, the gases are used directly in the process for heating, drying, or melting products instead of evaporating water in a boiler. The coal preparation, transportation, handling, and storage systems are also of the kind described above. Of the few

Exhibit 15.8

Fluidized Bed Steam Generator

Georgetown University, USA

45 Tonnes of Steam/hr; 45 bar Design Pressure Saturated Steam



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industries that are likely to burn coal as their major fuel, the cement industry is undoubtedly the most significant.

The selection of the right technology for a given type of coal is a complex exercise. A simple graphic approach based on the volatile content of the coal is presented in Exhibit 15.9. Selection between stoker and fluidized-bed systems for a given application should consider factors such as:

- Types of coal available
- Future environmental regulations
- Type of equipment available
- Operator skills
- Maintenance availability.

All these factors should be carefully assessed prior to undertaking the economic and financial analysis.

ECONOMICS OF COAL IN INDUSTRIAL EQUIPMENT

To illustrate the economics of coal versus other commercial fuels, boiler applications will be selected. As discussed in Session 3, economics of energy systems primarily depend on three categories of inputs:

- Capital costs
- Fuel costs
- Operation and maintenance (O&M) costs.

Each of these inputs is discussed below.

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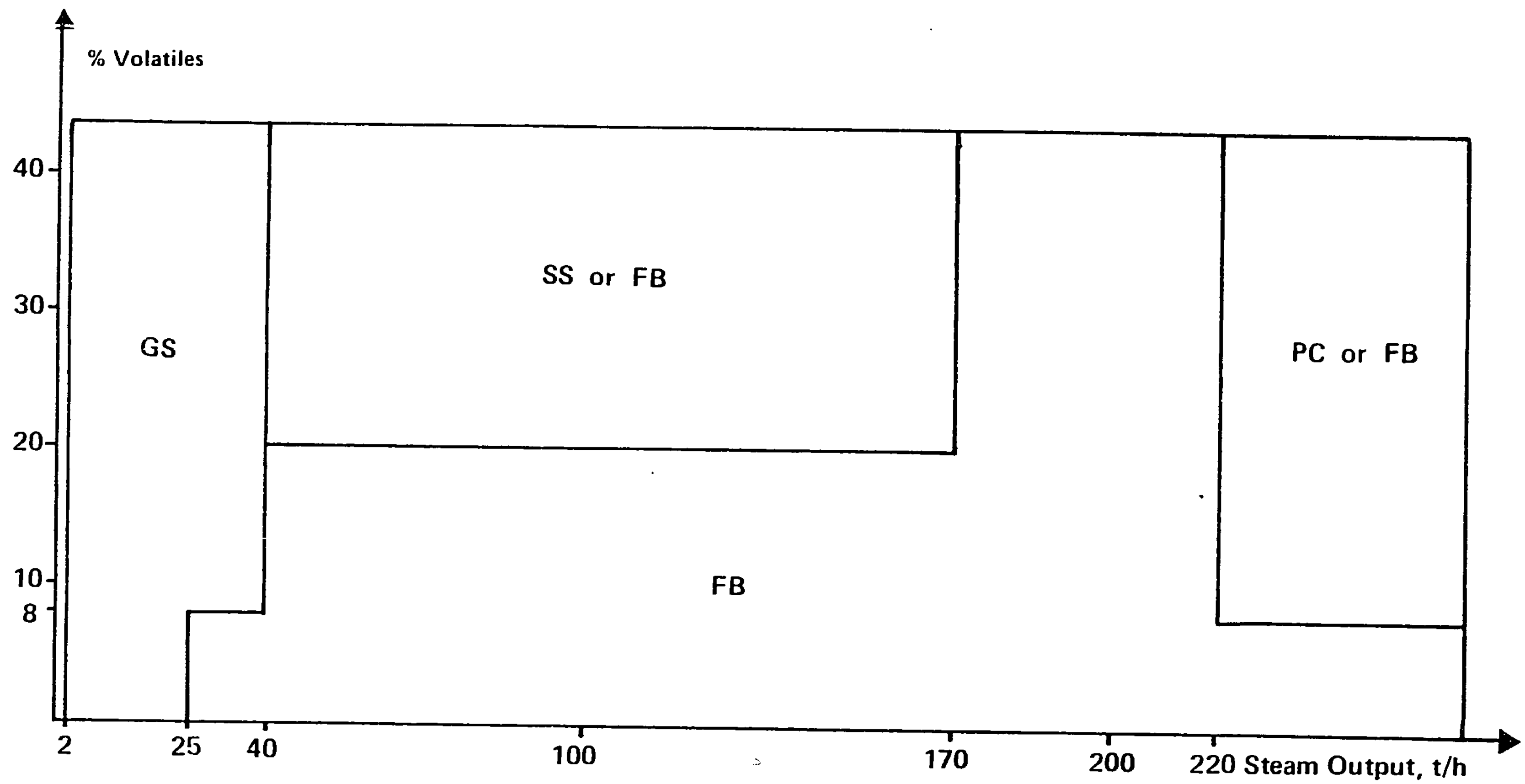
Exhibit 15.9

Influence of Coal Characteristics on Boiler Type Selection



G.S.: Grate Stoker

S.S.: Spreader Stoker

FB: Fluidized Bed

PC: Pulverized Coal

SOURCE: Hagler, Bailly & Company

Capital Costs

New coal-fired boilers typically cost two to three times more than oil or gas-designed boilers of the same characteristics (e.g., size, pressure, temperature). As shown in Exhibits 15.10 and 15.11, extrapolating U.S. costs indicates that a new 50 tsh coal-fired boiler, 85 bar, would cost approximately $6 million (late 1983) plus $1.6 million for coal handling and storage, for a total installed cost of approximately $7.6 million. A lower-pressure boiler plant (45 bar) of the same capacity could cost roughly $6 million; the boiler itself corresponds to only about 20 percent of the total installed steam plant cost (see Exhibit 15.11).

Corresponding total installed cost for oil fired systems would be approximately $4 million for the high-pressure system and $3.2 million for the low-pressure system (see Exhibits 15.10 and 15.11). Boiler cost alone would be in the range of $1 million to $1.6 million for coal-firing (see Exhibit 15.12). Boilers manufactured in India, Korea, or Czechoslovakia may be significantly cheaper.

Fuel Costs

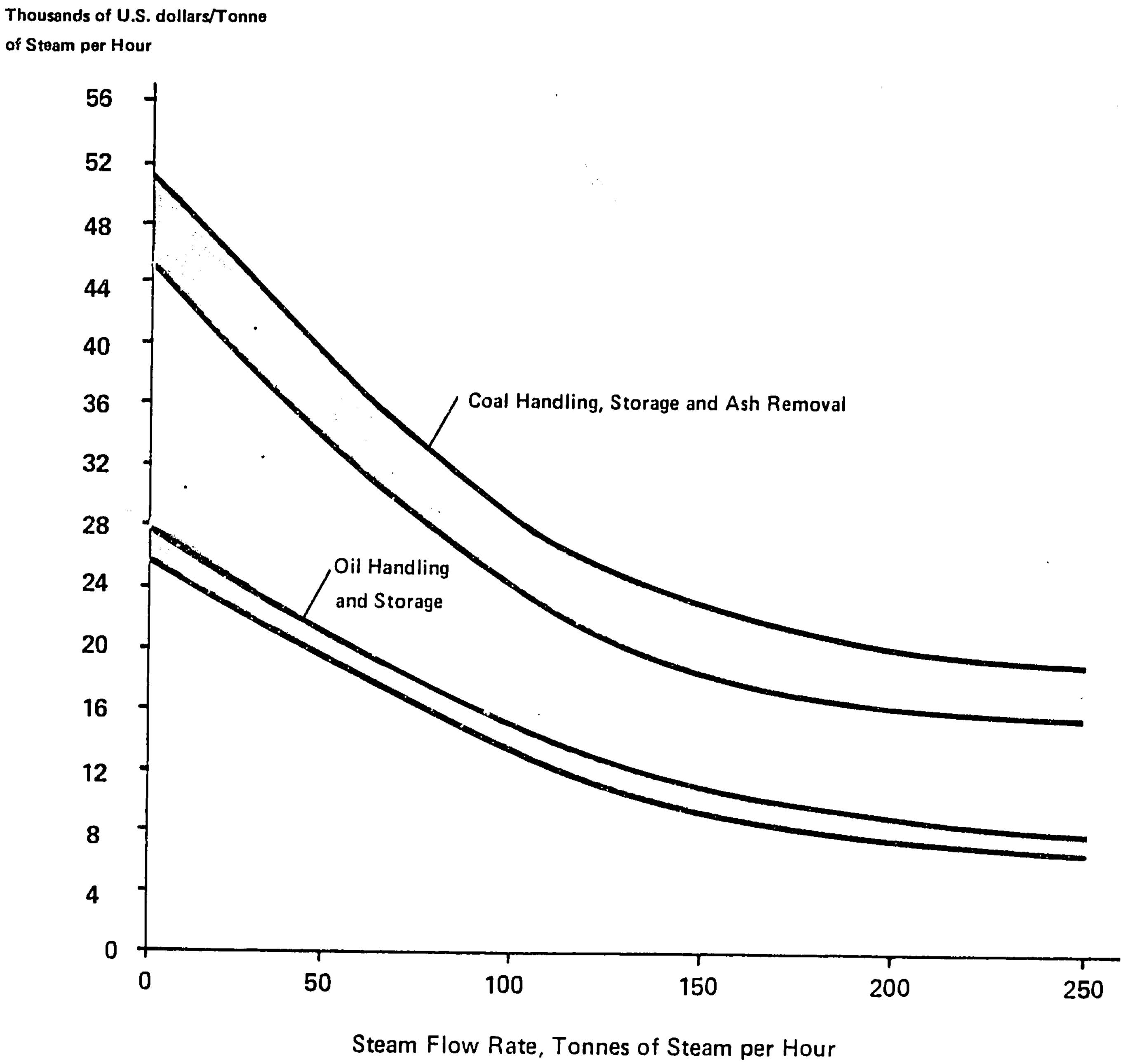
For a given boiler, the cost of using coal is typically one-third to one-half the cost of furnace oil. For example, a 25-tsh oil-fired boiler using furnace oil costing $0.20 per liter and 80 percent efficient would have hourly fuel costs of roughly $460. A similar boiler using coal costing $72 per tonne and averaging 28,000 kJ/kg would have an hourly fuel cost of $224, or less than half the hourly oil cost.

Operation and Maintenance (O&M) Costs

In the United States, O&M costs are often estimated as a fraction of capital cost. For large coal-fired boilers, annual O&M costs typically range between 6 and 8 percent of total installed costs. For smaller boilers, this percentage can reach 40 or 50 percent, owing to U.S. boiler regulations and high boiler operator wages. It is likely that maintenance costs alone would be higher in lesser developed countries than in the United States, but operator costs would be much lower. Consequently, average annual O&M

Exhibit 15.10

Installed Costs of Fuel Handling and Storage Equipment for Coal and Oil Fired Boilers



SOURCE: Hagler, Bailly & Company

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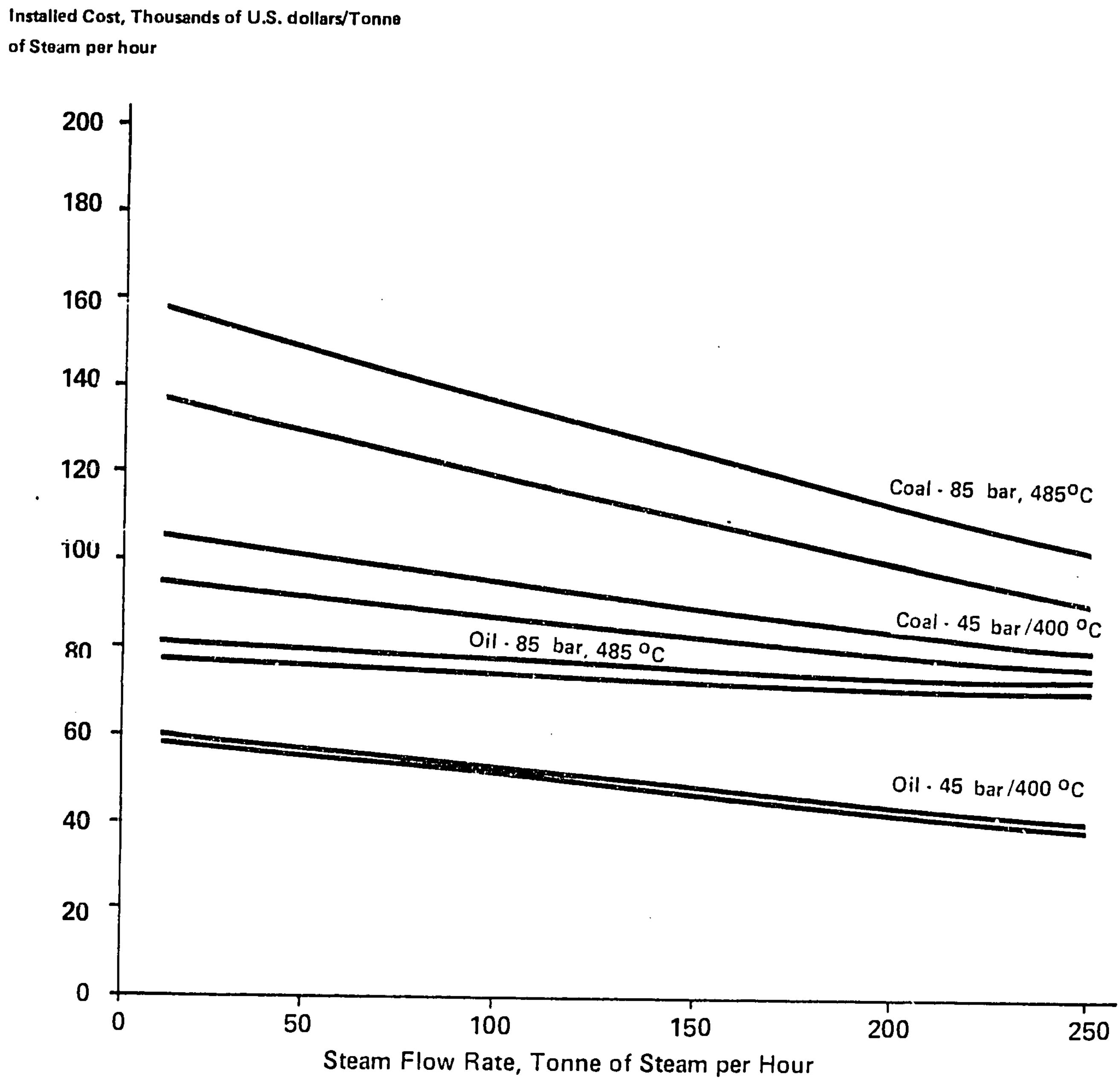
Exhibit 15.11

Installed Costs of Field Erected Steam Boilers for Coal and Oil Fired Boilers



SOURCE: Hagler, Bailly & Company

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Exhibit 15.12

Illustration of the Cost Structure of a New Coal-Fired Industrial Boiler Plant

	Percent of total installed cost
Equipment:	
Boiler	18
Coal handling system	4
Ash disposal system	3
Stokers	3
Other	3
Total equipment	31
Installation, direct:	
Boiler	11
Coal handling system	4
Buildings	4
Foundations and support	2
Other	8
Total installation, direct	29
Total direct costs (equipment and installation):	
Installation cost, indirect (engineering, construction expenses, fees)	19
Contingencies	16
Other (e.g., land, working capital)	5
Total	**100**

SOURCE: Hagler, Bailly & Company.

costs for medium and large industrial coal-fired boilers (i.e., greater than 25 tsh) are likely to be in the 5-7 percent range.

Exercise

Given the following system costs and performances, operating and financial conditions, what would be the maximum acceptable delivered coal price (constant currency -- i.e., no inflation) to ensure an incremental after-tax internal rate of return for coal versus oil of 25 percent for a new boiler plant?

System size = 50 tonnes of steam per hour (45 bar, 400°C)
Annual hours of operation = 6,000
Boiler efficiency (oil) = 82 percent
Boiler efficiency (coal) = 80 percent
Capital costs and O&M costs = from previous paragraphs and exhibits
Furnace oil price = $92.40/GJ
System life = 25 years for both systems
Tax rate = 50 percent
Financing = 100 percent equity.

APPENDIX 15.A: OPPORTUNITIES FOR USE OF COAL IN COAL/OIL AND COAL/WATER MIXTURES IN THE INDUSTRIAL MARKET[1]

INTRODUCTION

The technology for coal/oil mixtures (COM) combustion has been available since its first demonstration in the United Kingdom in 1879. Despite some interest in its use, primarily for marine steam turbines during both world wars, COM research was largely neglected until the 1960s and 1970s. The awareness of price disadvantages and long-term supply shortages for oil and natural gas have led to a new era for coal as an industrial and utility boiler fuel. In this context, COM is now being reassessed as a boiler fuel.

Considerable difficulties are faced by existing fuel oil users wishing to reduce oil consumption by substitution technologies. Converting coal into oil or gas does not offer an immediate solution to the problem. The conversion of an oil-designed plant to solid coal firing is rarely an option. In most cases, the existing plant would have to be scrapped and replaced by new coal-designed facilities requiring coal handling equipment and coal stockpiling, which may be physically difficult or financially unattractive, particularly if there is a shortage of capital. The most likely opportunities for conversions to solid-fuel firing are where a coal-designed plant has been converted to oil-firing and can be reconverted, or where exhausted oil boilers are to be replaced.

The space requirements and the influence of fuel type on boiler design are perhaps the most significant factors precluding the direct substitution of coal in boilers designed for oil firing. However, COM is potentially a more flexible fuel than coal; its composition can be adjusted to influence the amount of sulfur, mineral matter, and other materials in the fuel. A typical COM contains approximately 50 percent (by weight) finely ground coal and 50 percent (by weight) residual oil, with less than 1 percent (by weight) chemical additives. The handling and combustion characteristics are much nearer those of the parent oil than the parent coal. Stabilized COM can be transported by pipelines to

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*Most of this appendix has been adapted from a paper prepared by the Central Planning Unit of the National Coal Board, United Kingdom, for the International Energy Agency.

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the point of use. Even so, as with conversion to coal (though to a lesser extent), conversion to COM depends very much on the original plant design.

Most of what is true for COM is also true for coal/water mixtures (CWM). CWM typically consist of 70 percent (by weight) finely ground coal, 29 to 29.5 percent (by weight) water, and 0.5-1.0 percent chemical additives. The major differences are that CWM are not yet fully proven, and their economics appear more promising vis-a-vis oil than COM for the very reason that they do not contain oil (see Exhibit 15.A).

COAL/OIL MIXTURES (COM) TECHNOLOGY

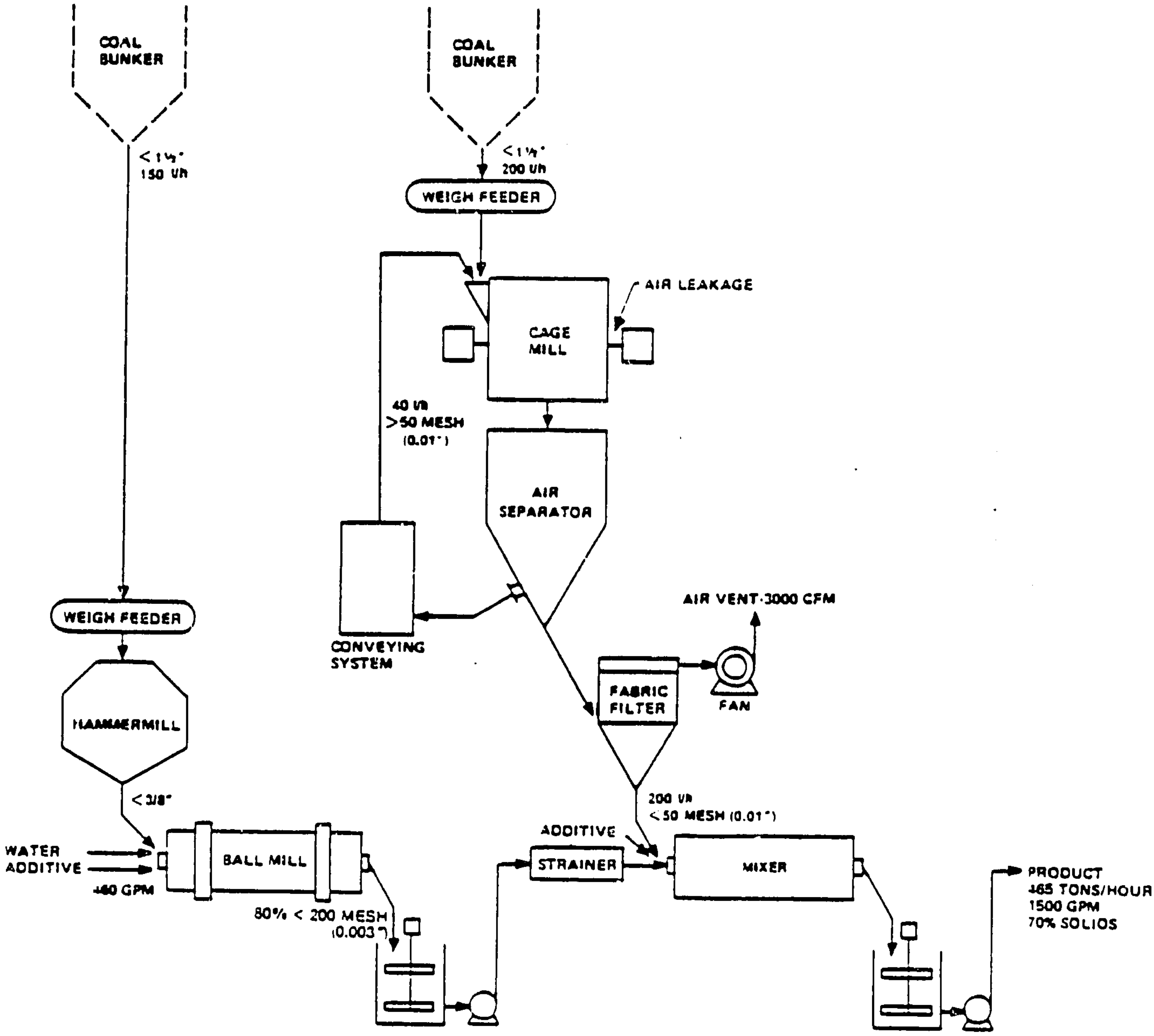
A coal/oil mixture can be considered a liquid fuel source only if it can be stabilized. That is, if -- through the addition of chemicals and/or water or through a sophisticated dispersion technique -- the mixture can be prevented from separating into its constituent parts.

Mixture stability, or the degree to which particles remain suspended in oil, is perhaps the most serious problem in the use of COM. COM can be prepared for long-term stability by introducing additives to the mixture, through fine pulverization of the coal, ultrasonication, or by combinations of these methods. An unstable COM undergoes agglomeration and rapid sedimentation of suspended particles, causing excessive wear of boiler pumps and valves, blockages of pipes and related equipment, and non-uniform flow. Even with a COM that is stable in long-term storage, after heating prior to firing, there is a possibility of separation if the flow is stopped, depending on the size of the coal particles. In addition, a COM flow that has a varying solid concentration or flow rate results in an unpredictable heat input to the boiler.

The higher the coal concentration in the mixture, the cheaper the COM fuel relative to oil. However, as well as affecting mixture stability, coal concentration influences fuel line erosion, fly ash and other emissions, combustion efficiency, boiler efficiency, and, in particular, fuel viscosity. In general, the smaller the particle size, the greater the stability, although less grinding is required if additives are used to achieve stability.

Exhibit 15.A

Coal Water Mixture Preparation



SOURCE: Coal-Water Slurry as Utility Boiler Fuel, prepared by Atlantic Research Corporation, published by Electric Power Research Institute, EPRI CS-2287, March 1982.

COM have been prepared successfully using a variety of fuel oils and a range of coals. Although COM is still at the development phase, it now appears unlikely that fuel property considerations will be a barrier to the use of COM as a boiler fuel.

COAL/WATER MIXTURES (CWM) TECHNOLOGY

CWM are about 5 years behind COM in technical development, and there is more diversity among the various CWM formulations than is the case with COM. There is still little experience in firing CWM; also, full-scale tests are now being conducted in the United States, Canada, and Sweden. In addition to all the technical problems mentioned above, CWM storage and combustion face additional difficulties, including long-term storage, water evaporation during combustion, fuel atomization, burner wear, limited flame stability, and limited load following capabilities (turndown). However, there is now a worldwide consensus that by the end of this decade, CWM will be commercially available in many countries and make COM obsolete.

POSSIBLE APPLICATIONS OF COAL-LIQUID MIXTURES (CLM)

Applications of CLM (i.e., COM and CWM) fall into two categories: those medium-term applications created because CLM are cheaper fuels than oil to burn in existing plants, and those applications where the specific characteristics of CLM make them suitable fuels in the long term.

Fuel for Existing Boiler Plants

Fuel for existing boiler plants is the area most likely to lead to a substantial growth in the use of CLM. Given that there are no problems in achieving feedstock requirements (with up to 70 percent coal) and satisfactory transportation and storage of CLM are present, the economics of CLM firing depend on the minimum alteration or modification of boiler equipment. CLM can be substituted for oil in either power generation boilers or industrial steam-raising boilers.

CLM should be seen as a potential means of converting existing plants to partial coal use only **where full conversion to coal is uneconomic or impossible**. Boilers designed for coal firing but currently burning oil can generally be reconverted to solid coal firing, provided that:

- Adequate space for coal unloading, storage, and transport exists
- Equipment for crushing and pulverizing the coal and for gas cleaning can be reinstated or installed
- Coals of suitable quality are available.

If one or more of the above conditions are not met, reconversion may be practically impossible or involve significant derating of the furnace output. In general, boilers designed for oil firing can only be converted to coal with a 40 to 70 percent derating, because of the relatively small combustion chamber and the need to reduce gas velocity to avoid erosion of the tubes.

The problems and cost of converting existing boilers to coal create the potential for conversion to CLM. Having similar combustion characteristics to those of No. 6 fuel oil enables CLM to be burned in boilers that were designed originally for coal or oil but are not capable of burning coal for economic or practical reasons.

When a new plant is to be constructed, the most economic means of generation is through coal firing. CLM-fired new plants should only be considered where space limitations make coal firing uneconomic or impractical. If the CLM is manufactured in bulk at refineries, for instance, space is required at the plant site only for storage, not for manufacturing purposes.

Since the substitution of CLM is seen as a means of reducing the costs of running existing boilers without major capital expenditure, the economics of CLM firing depend on the minimum alteration or modification of boiler equipment. The boiler efficiency with CLM will be close to that with oil, but the nonfuel operating costs will be greater because of increased maintenance and, perhaps, increased power requirements.

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Boilers Designed Originally for Coal

Boilers designed for coal but subsequently converted to oil burning are the easiest to convert to CLM use. In the United States alone, there is approximately 11 GW of generating capacity having, at a minimum, partial coal-firing capacity, although the position in the industrial market is less clear. Such plants could feasibly be converted to CLM at reasonably little cost. CLM will generally be prepared at centralized plants, but in the case of large users, there may be advantages in preparing the CLM at or near the user's site if space is available, although this may well be less attractive than the use of pulverized coal.

A boiler currently burning residual oil must undergo a number of modifications to burn CLM:

- Filters to capture oversized particles of agglomerates must be modified.
- Pumps with hardened surfaces will be needed to move and handle the CLM and to withstand possible corrosion and erosion.
- Depending on the stability of the CLM, feed lines may have to be rerouted to eliminate areas where settling may take place.
- If a non-stabilized CLM is used, an agitation system will be necessary.
- Burners will have to be fitted with tips of hardened material.
- Depending on the sulfur level of the residual oil already being burned and of the CLM to be substituted for it, sulfur dioxide control equipment may be required.
- Particulate collection will be required if not already installed.
- Ash accumulated in the interior of the boiler wil have to be removed by sootblowers (which are currently installed in many residual oil-fired boilers) but which may have to be upgraded.
- Additional air and fuel preheating may be required.

Boilers Designed Originally for Oil

It is unclear how much a boiler designed for burning oil would have to be derated to burn CLM: "Experience of firing COM in small scale industrial boilers has shown that

COM combustion characteristics are very similar to those of No. 6 fuel oil and that the mineral matter in the COM leaves the boiler as fly ash. Therefore, when converting an oil-fired boiler to COM, constraints of boiler size and internal spacing are not so important as for conversion to coal. Indeed, an oil-fired boiler shoud be capable of operating on COM with a minimum of derating. If derating is required on a 50-50 coal/oil mixture, the percentage of coal in the mixture can be reduced to maintain the original rating." (fron Morrison, IEA, December 1979.)

Derating with CLM may range from zero in a coal-designed boiler to 50 percent in a boiler designed to burn diesel oil.

Derating can generally be minimized by selection of a coal component with a low ash content and a high ash fusion temperature, and by pulverizing to a finer size. The lower calorific value of CLM relative to fuel oil is also a potential cause of derating, but most oil-fired boiler feed systems are capable of increasing the fuel delivery rate to counteract it.

In addition to the modifications listed in the previous section for boilers designed originally for coal, new equipment would need to be installed on an oil-fired boiler to permit a proportion of coal-firing, including:

- Modification of the furnace bottom to allow ash extraction, together with associated ash handling facilities. If the space between the furnace bottom and the floor is inadequate for this purpose, expensive excavation may be necessary.
- If the CLM were made on site, space would be required and equipment installed for the coal storage/handling and CLM preparation. Pulverizing mills would be needed.

In general, the capital cost and down time required for conversion to CLM firing are modest by comparison with that for re-equipping to burn coal for the larger industrial boilers.

Also, in moving from a clean fuel to a fuel containing mineral matter, some form of bottom ash removal and fly ash collection must be incorporparted, together with the

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installation of sootblowers to remove deposits accumulated on heat transfer surfaces. A complete liquid fuel feeding system must be employed. It is unlikely that a refitted boiler design could successfully cope with the fouling tendencies of coal slag and fly ash on boiler heat transfer surfaces originally built to accommodate clean fuel combustion products.

COST OF CLM

The commercial attractiveness of CLM will depend principally on the relative prices of coal and heavy fuel oil. While the coal/fuel oil price differential is bound to fluctuate, there is a reasonable expectation that the trend will be toward a widening of the differential in the long term. CLM fuels will have to be sold at a discount on the prevailing fuel oil price (on a thermal equivalent basis) to provide the potential user with sufficient incentive to use CLM rather than fuel oil, and to give an adequate return on the capital required for any necessary plant modifications.

COST OF CONVERSION TO CLM PLANT

The capital costs of converting an oil boiler to CLM firing are necessarily very uncertain at this stage of development. However, some tentative estimates are presented below for the United Kingdom. The costs of converting both firetube and watertube boilers are presented, and the modifications are costed as a percentage of the cost of a new firetube or watertube coal system (including ancillary equipment), respectively. The coal system is the alternative investment facing a user.

THE CAPITAL COST OF CONVERTING BOTH
FIRETUBE AND WATERTUBE OIL-FIRED BOILERS TO COM FIRING

Modification	Cost of modification as % of cost of new coal system	
	Firetube boiler	**Watertube boiler**
Work on liquid feed/storage system	1-3	1
Sootblowers	2-3	1-2
Flue gas cleaning	8-13	3-6
Ash removal from boiler	1-2	1-3
Total	12-21	6-12

The costs of converting a watertube boiler to COM firing reflects the fact that watertube boilers cost up to four times as much as firetube boilers per MW output. However, there is no reason to believe that the costs of the modification to the feed/storage system or the provision of gas cleaning equipment will be significantly more expensive per MW than for firetube boilers. However, the cost of providing ash removal from the combustion chamber may be more in the case of a watertube unit. Converting to CWM would typically be 50 percent more expensive than to COM.

SESSION 16: WOOD BURNING

Although the amount of biomass used by industry is not known with precision, preliminary estimates indicate that biomass fuels -- mostly wood -- would account for almost half the total energy used in the industrial sector, at 520,000 toe.

Because the governments of less developed countries have embarked on aggressive forest management programs, and because of the importance of agroindustries in these countries, biomass fuels -- primarily wood and wood waste -- are likely to continue to play a significant role in the industrial sector. In this session, we will review the combustion characteristics of biomass fuels, their industrial energy application, the technical considerations involved in retrofitting existing oil-fired equipment, and will present the economics of wood combustion.

WOOD COMBUSTION CHARACTERISTICS*

Wood is one of the group of fuels called biomass fuels. They find their source in living matter, the original source of all fossil fuels, including coal and oil. To better understand the use of wood as a fuel, we need to compare it with the properties of the fossil fuels it can displace.

During the fossilization process, the molecular form of carbon -- the principal source of energy -- is changed as some hydrogen, oxygen, water, and other compounds and elements are driven off. The fossilization process has two other results that are of importance in comparing wood and fossil fuels. During fossilization, the complex molecular structure is broken down -- in essence, a step equivalent to one of the steps in the combustion process. In addition, during the years underground, the fossil fuels pick up contaminants such as sulfur and vanadium. These elements, which are not present in significant quantities in wood, can present major pollution problems when fossil fuels are burned.

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*Adapted from publications by the U.S. Solar Energy Research Institute.

The physical and chemical makeup of wood is also important. Wood is composed of the many cells that make up a living tree and, as is true of all living things, large amounts of water. The cell walls are made up of long chain polymers, principally cellulose and hemi-cellulose, bound together with a cellular glue, lignin. The large amount of space in the cell structure contributes to the relatively low energy density of wood. Part of the space is filled with water, and the rest is filled with air.

Carbon is the principal source of energy in both wood and fossil fuels. Exhibit 16.1 shows a typical elemental analysis of wood compared with coal. Coal, the major solid fossil fuel, contains less hydrogen and oxygen than does wood. Since wood has more oxygen, it yields less energy per unit weight.

The combustion of wood and fossil fuels takes place with the same net chemical reactions:

$$2H_2 + O_2 \qquad 2H_2O + \text{heat}$$
$$C + O_2 \qquad CO_2 + \text{heat.}$$

Though both reactions are exothermic, the carbon-oxygen reaction yields more net heat. Carbon, present in larger quantities than is hydrogen, accounts for most of the energy released.

The actual burning process takes place in three stages. First, the moisture must be driven off before ignition can take place. The energy absorbed in this stage goes into the phase change of the water so the temperature stays at the boiling point, about 100°C. Moisture content determines the amount of energy and time required to complete this stage. If the percentage of water is high enough (above 67 percent), ignition will not be sustained. This "black-out zone" results from the water absorbing enough energy to prevent the temperature from rising to the ignition point.

The second phase of combustion is probably the most important. As mentioned earlier, wood is made of complex polymeric compounds that break down or destructively distill at temperatures from about 150°C to 500°C. Most are evolved as gases that burn outside the fuel particle when they combine with combustion air. These gases contain methane, small quantities of other hydrocarbons, and a large percentage of carbon monoxide (CO). What makes this phase so important is that from 60 to 80 percent of the

Exhibit 16.1

Typical Elemental Analysis of Wood and Coal
(On a dry weight basis)

	Coal	Wood
Carbon	75.5	52.0
Hydrogen	5.0	6.3
Oxygen	4.9	40.5
Nitrogen	1.2	0.1
Sulfur	3.1	0.01
Ash	10.3	1.0

weight of the dry wood evolves as these gases. Thus, much of the energy released in burning comes from this "flaming combustion."

The final stage of combustion is the oxidation of the carbon left after the volatiles have been driven off. This fixed carbon occurs mainly in elemental form and is mixed with inorganic ash to form charcoal. The oxidation takes place at the particle surface as oxygen comes in contact with the exposed surface. This "glowing combustion" evidences no flame but is rather a surface effect taking place at over 500°C.

Heating value is the amount of thermal energy released when wood is burned. There are three different ways of defining heat value, each yielding a different number.

Gross heating value (GHV), the total heating potential of a unit of wood as delivered, is found by placing the moisture content (MC) of the fuel and the higher heating value (HHV) in the following equation:

$$GHV = HHV\ (1 - MC/100)$$

where MC is percent moisture content of the fuel on a wet weight basis.

GHV reflects the effect of moisture displacing combustible material, and can be thought of as the higher heating value of the wood in a green unit of fuel.

HHV is the total thermal energy released by a unit of **oven dry fuel**. This is the number reported from a bomb calorimeter test and is usually in units of Btu per pound or kilocalories per kilogram. The "Parr Bomb" test involves burning a sample of fuel in a sealed container, cooling the products of combustion to their initial temperature, and measuring the heat released. Reported HHV for wood and bark generally ranges from about 18,400 kJ/kg to a little over 23,240 kJ/kg. Exhibit 16.2 gives HHVs for representative wood types and fossil fuels.

Finally, net heating value (NHV) represents the energy available for doing work. This value takes into account the negative heating value of water. The water in wood must be vaporized and superheated in the furnace. There is a net consumption of

Exhibit 16.2

Typical Higher Heating Values
of Some Wood and Fossil Fuels[1]

Fuel type	HHV (kJ/kg)
Southern pine bark	20,691
Hardwood whole tree chips	19,980
Wood pellets	19,980
Bituminous coal	32,537
No. 2 heating oil	45,085
No. 6 heating oil	42,532
Louisiana natural gas	50,666

[1]An average HHV for wood of 19,755 kJ/kg is used in this text.

approximately 2,788 kJ per kg of water when this superheated vapor is expelled at $200^{o}C$ at atmospheric pressure.

The following formula can be used to calculate NHV:

$$NHV = HHV\ (1 - MC/100) - MC/100 \times LH_2O$$

where LH_2O = heat to vaporize and superheat 1 kg of water, approximately 2,788 kJ/kg.

Exhibit 16.3 gives representative NHVs for wood and fossil fuels.

The proximate analysis test has proved valuable in analyzing wood combustion. This test, developed for coal, determines the percent weight that will boil off as volatiles and the percentages of fixed carbon, water, and ash. Exhibit 16.4 gives typical proximate analyses for wood and coal.

Moisture content is probably the most important factor affecting wood as a fuel. Moisture reduces flame temperature, replaces combustible material, and releases heat from the boiler as superheated steam. The calculation of GHV and NHV illustrates these last two effects.

Assuming:

HHV	=	19,755 kJ/kg
MC	=	40 percent
T_l (ambient stack)	=	$200^{o}C$
LH_2O	=	2,788 kJ/kg (from tables for superheated steam, $200^{o}C$ at 1 bar pressure)

then:

GHV	=	HHV (1 - MC/100)
	=	19,755 (1 - 0.4) = 11,853 kJ/kg
LH_2O	=	2,788 kJ/kg (net energy added to 1 kg of superheated steam at 1 bar and $200^{o}C$)

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Exhibit 16.3

Representative Net Heating Values for Various Fuels

	Higher heating value (kJ/kg)	Moisture content (percent wet weight basis)	Net heating value (kJ/kg)
Coal	30,213	2.5	29,285
Oil	43,577	--	43,577
Gas	50,666	--	50,666
Dry wood	19,755	10.0	15,178
Wet wood	19,755	50.0	8,485

Exhibit 16.4

Proximate Analyses of Wood and Coal

	Moisture content (percent)	Volatile matter (percent)	Fixed carbon (percent)	Ash (percent)
Bituminous coal	2.5	37.6	52.9	7.0
Hardwood (wet)	45.6	48.58	5.52	0.3
Hardwood (dry)	0	89.31	10.14	0.56
Southern pine (wet)	52.3	31.5	15.9	0.29
Southern pine (dry)	0	66.0	33.4	0.6

and

$$NHV = GHV - MC/100\ (LH_2O)$$
$$= 11{,}853 - 0.4\ (2{,}788) = 10{,}737.8\ kJ/kg.$$

Although the chemistry of combustion for wood is similar to that of fossil fuels, three unique characteristics of wood combustion must be accounted for in furnace design. First, the high moisture content causes large volumes of superheated steam to be evolved in the firebox and depresses the temperature of combustion. Second, depending on fuel quality, large amounts of excess air are required for combustion. Third, residence time in the firebox must be sufficient to allow combustion of volatiles and entrained particles. Therefore, the firebox must be large enough to maintain reasonable gas velocities and must contain significant refractory material to sustain the temperature of the fire when wet fuel is used. These technical considerations are discussed in the following paragraphs.

ENERGY APPLICATIONS

The use of wood fuels can be classified into two broad categories: direct combustion and thermochemical conversion. In direct combustion, the chemical energy in wood is converted to thermal energy through the rapid reaction of the hydrogen and carbon in the wood with oxygen in air. The thermal energy is used for process heat or process steam. In thermochemical conversion, the chemical energy of the wood is converted to a gas (low-GJ gas, see Session 18), liquid (pyrolytic oil), or solid (charcoal). The converted product can then be combusted to produce thermal energy. The primary advantage of thermochemical conversion is efficiency of handling and combustion of the converted fuel. A brief discussion of the state-of-the-art of wood combustion and conversion technologies is presented below.

Direct Combustion

Several types of wood-fired combustion systems are available. Prior to 1950, the Dutch oven was the most commonly used system. Wood is fed into the oven from the top

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and falls onto a water-cooled grate where most of it is gasified. (This type of combustion is also called "pile burning.") The gases produced are mixed with air and travel to a combustion chamber where they are burned to produce the heat required for steam generation. Though Dutch ovens are still used today, they are being replaced by larger and more efficient combustion systems such as spreader-stokers and suspension systems as well as advanced fluidized-bed systems.

A summary of the firing methods currently used is presented in Exhibit 16.5 and briefly described below.

Stoker Systems

As discussed in earlier sessions, there are three types of stokers: underfeed, crossfeed, and overfeed (i.e., spreader-stoker). They differ mainly in the relative directions of the flows of fuel and air.

Of these three types, spreader-stokers are now the most widely used because they handle a range of solid feedstocks, respond rapidly to load changes, and operate efficiently with comparatively low excess air. As shown in Exhibit 16.6, the wood fuel is spread pneumatically or mechanically across the combustion chamber onto the surface of a grate. Small fuel particles burn in suspension while larger pieces fall and burn on the grate. The feed system is designed to spread an even, thin bed of fuel on the grate. The flame over the grate radiates heat to the fuel to aid combustion. Both underfired and overfired air are used for controlling the combustion process. The furnace walls are normally lined with tubes for heat exchange. Because there is little refractory material, the furnace can respond quickly to load variations. Construction and maintenance costs of these furnaces can be quite low.

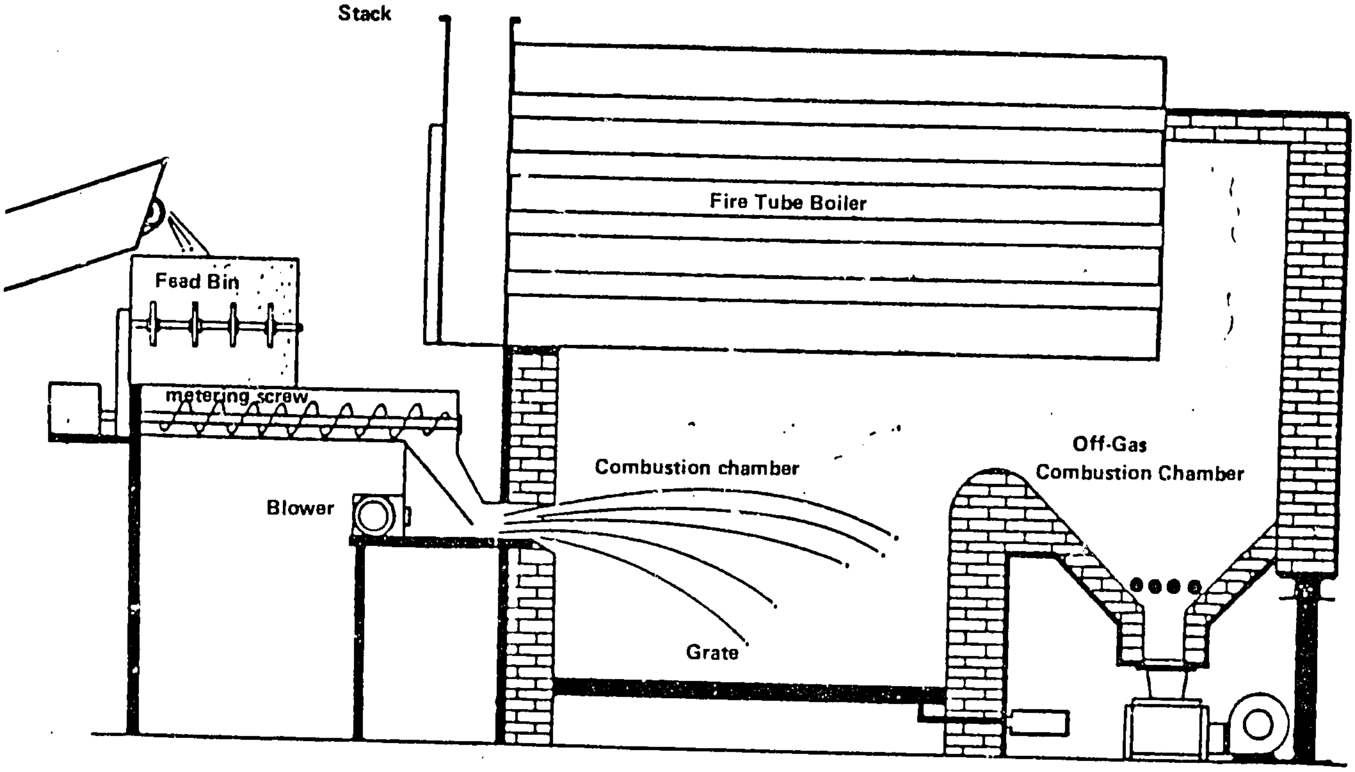
Many types of stoker systems are presently manufactured. These can be grouped into two categories: single-chamber combustion or multi-chamber combustion. In the multi-chamber system, partial oxidation of the fuel with substoichiometric air occurs in the first chamber, followed by off-gas combustion in the additional chambers. The multi-chamber design separates the gasification step from the main combustion step, therefore minimizing ash carryover and improving control of combustion. Single-chamber units

Exhibit 16.5

Commercial/Industrial Technologies

Technology	Description	Fuel type	Efficiency	Size range
Stoker systems	In stoker firing, hogged fuel or wood chips are either flipped or blown into the combustion zone of the boiler. Small particles burn in suspension, while larger pieces burn on the grate.	Hogged wood, wood chips, bark, etc. Typical particle size ranges between 19 mm and 38 mm.	57-68%	26.3-529.2 kJ/hr
Package systems	This system uses a fuel cell firing method. A refractory-lined chamber is used as a fuel burner cell.	Hogged wood, sawdust, bark, planer shavings, etc.	65-70%	10.5-52.7 kJ/hr
Suspension burner systems	The COEN DAZ Scroll feed burner is an automated burner for handling fine organic residues. This burner can be used to retrofit oil- and gas-fired boilers.	Requires fine (0.8 mm) and dry feed material. Will burn sander dust, particle board trim, bark, sawdust, etc.	65-75%	10.5-52.7 kJ/hr
Fluidized-bed systems	Fluidized-bed systems are preferred for burning dirty fuel, or high moisture content fuel that is not easily burned in a conventional system. The boiler integrated with this fluidized-bed burner generally will be a firetube design.	Wood waste and residue, fuel containing significant amount of foreign materials (sand, glass, etc.).	60-75%	10.5-52.7 kJ/hr

Exhibit 16.6
Typical Spreader Stoker Boiler System



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are more difficult to control than multi-chamber units, emit more particulates, and have a relatively low turndown ratio. Alternately, single-chamber units are simpler to operate and have a lower cost than multi-chamber units.

Stoker systems can incorporate various grate designs. Among the possibilities are stationary or continuously moving grates, fixed or dumping type grates, flat or inclined orientations, and air-cooled or water-cooled designs. Selection of a particular grate design depends on furnace capacity, fuel characteristics (i.e., heating value and moisture and ash content), combustion air requirements, and maintenance considerations. Exhibit 16.7 shows a complete stoker system with its associated storage, feeding systems, and environmental controls.

Stoker systems are a commercially proven technology. According to the American Boiler Manufacturers Association, wood-fired stoker boilers represent 14 percent of all boilers in the size range of 50 to 150 tonnes of steam per hour sold in the United States in the last 10 years.

Package Systems

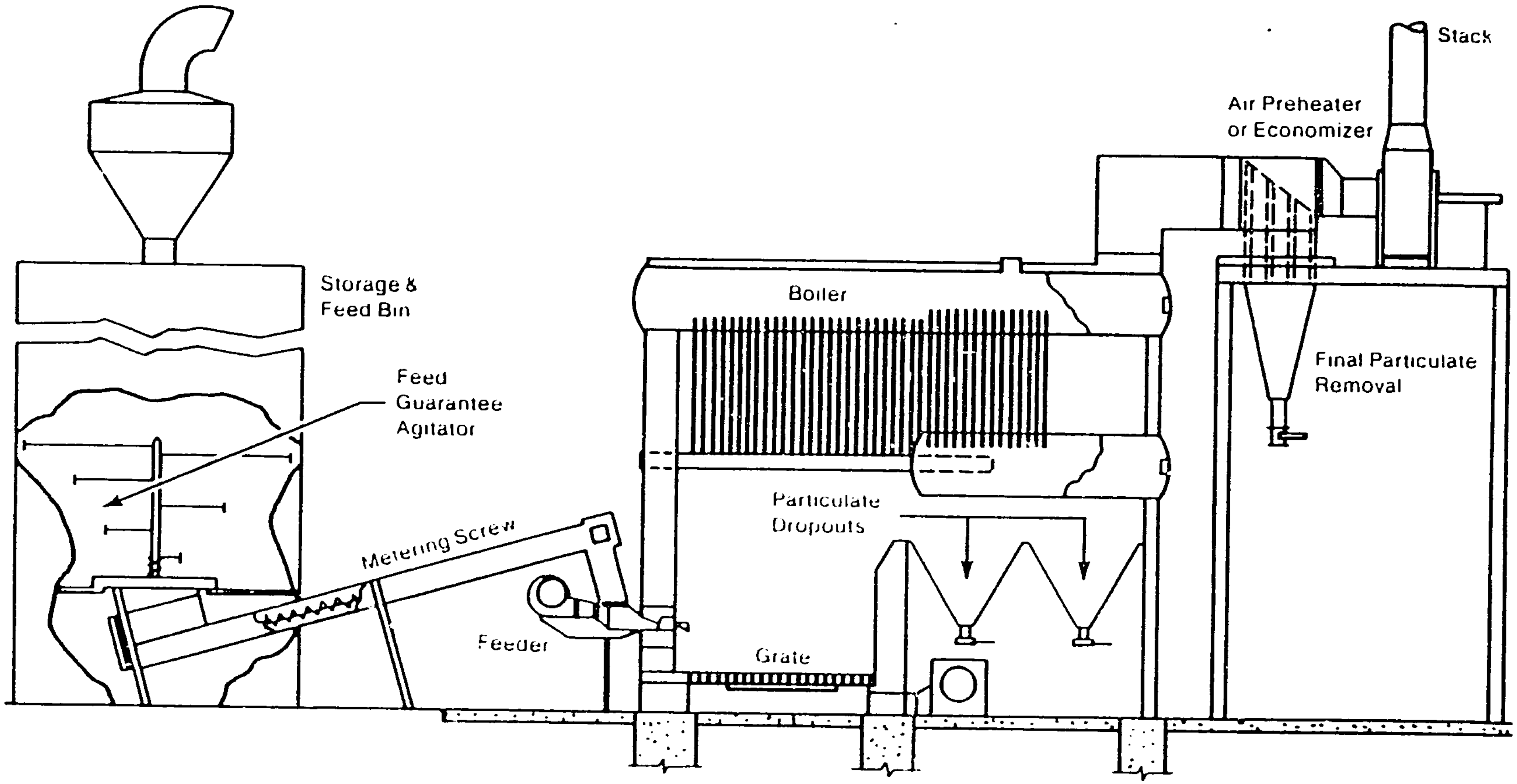
Package systems are shop-assembled units shipped completely ready to connect and operate. Package boilers with capacities of up to 30 tonnes of steam per hour are in this category. When higher steam outputs are required, several units can be operated in parallel. Wood-fired package boilers are a commercially proven technology. About 100 wood-fired package boilers were reported to be in operation in North America as of 1978.

Package boilers can generate hot water, low-pressure steam, or, in some designs, high-pressure steam. The units are fully automated and designed for simplicity and flexibility of operation. In some designs, wood fuel of fairly large size (end cuts, for instance) and high moisture content (50 to 60 percent wet basis) can be used, thus eliminating the constraints of fuel drying required for suspension burners.

The design of package boilers differ by the type of combustion chamber and combustion system used, the type, size, and moisture content of the fuel tolerated, and the need

Exhibit 16.7

Automatic Stoker Direct Combustion Solid Fuel Boiler



for supplementary fuel. In most package systems, a refractory-lined chamber is used as the fuel burner cell. The refractory chamber enhances high temperatures for smoke-free combustion. Package wood-fired boilers range in size from 1 to 30 tonnes of steam/hr with combustion efficiencies between 65 and 70 percent. Package systems are generally designed for automatic control. Properly sized wood fuel is continuously supplied from a storage bin to the fuel cell burner. A sample package boiler system with its ancillary equipment is shown in Exhibit 16.8. Exhibit 16.9 shows a similar arrangement for direct heat applications.

Suspension Burner Systems

In suspension burners, relatively fine particles of wood or other organic material are mixed with air and burned in suspension. Suspension firing of wood is similar to pulverized coal firing. As of 1978, more than 200 units were reported to be in operation in the United States. Some of these units have been in service for over 15 years.

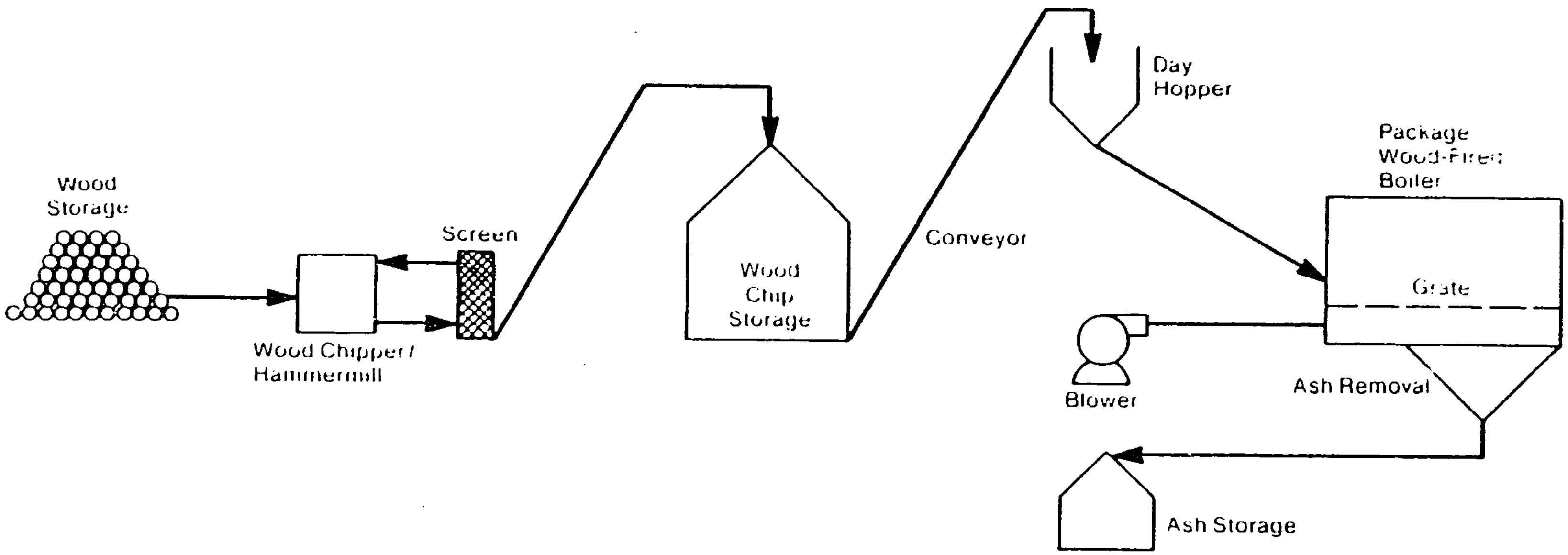
Suspension burners produce a relatively clean hot gas which can be used in various industrial processes. The burners can also be used to retrofit existing oil- or gas-fired package boilers producing less than 25 tonnes of steam per hour. Suspension burners are generally fully automated and have sufficient turndown capability to respond to variable energy demands encountered in process applications.

The major disadvantage of suspension burners is that they require dry, fine fuel. Dry fuel may be available at some industrial locations (planner shavings, for instance). In other situations, the fuel must be dried to the moisture content required by the suspension burner design. In most cases, the dry wood fuel must be hammermilled to the size required by the burner. The cost of these fuel preparation steps, as well as fuel storage and fuel handling equipment, may bring the cost of the total wood-fired system to two or three times that of the burner alone. Suspension burners also require some electrical power for wood feed and air blowers and may require auxiliary fossil fuel for startup and operation.

The thermal efficiency of a boiler using suspension burners is around 75 percent. This efficiency corresponds to a 10-percent moisture feedstock, 25 percent excess air, and

Exhibit 16.8

Wood-Fired Package Boiler



Package Wood Fired Boiler Systems:

- Wood storage shed
- Wood chipper / hammermill and screens
- Conveyors
- Wood chip storage
- Day hopper
- Stoker
- Air cooled grate
- Ash removal and storage
- Boiler
- Electrical and instrumentation

Daily Fuel Input

250 HP	13.2 ODT / day
500 HP	25.4 ODT / day
1000 HP	52.8 ODT / day

H.V. of Fuel: **19.7 GJ/ODT wood**

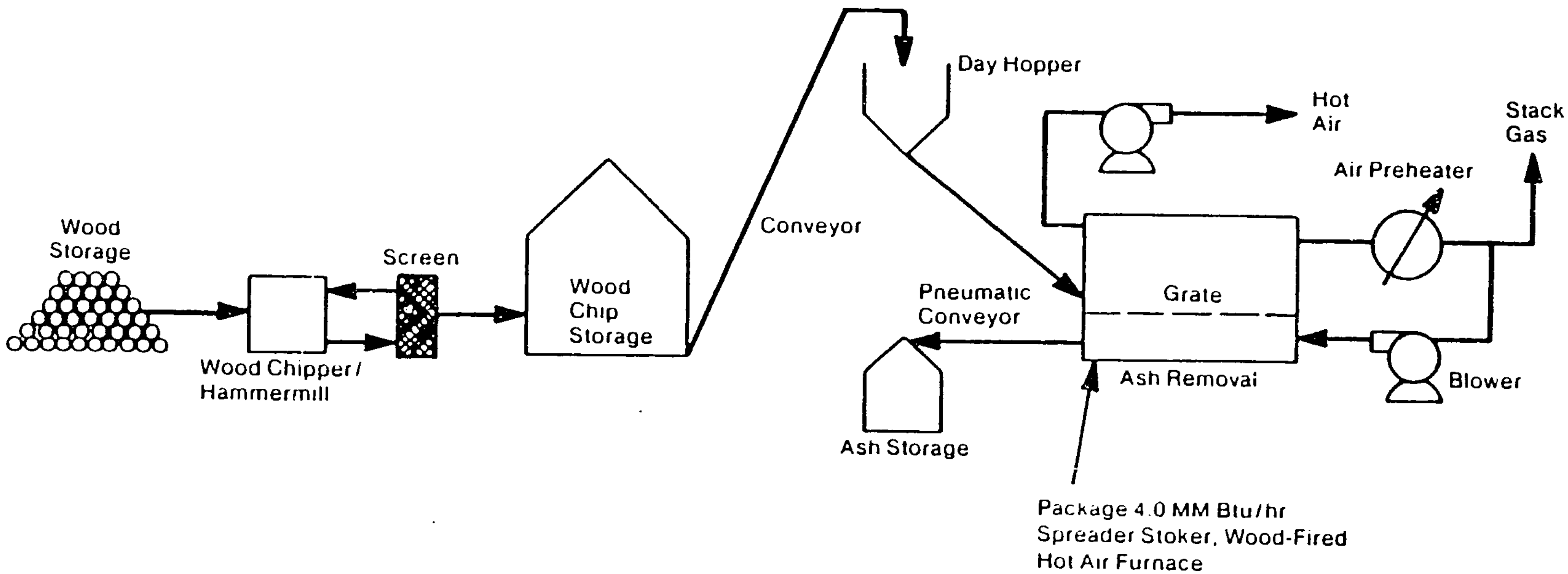
Moisture Content of Fuel: 43% on a dry basis

Boiler Efficiency: 0.65

Additional Land Required: 250 HP — 0.35 hectares

Exhibit 16.9

Package Wood-Fired Hot Air Furnace — 4.2 GJ/hr for Direct Heat Applications



Package Wood Fired Hot Air Furnace:
- Wood storage shed
- Wood chipper / hammermill and screens
- Conveyors
- Wood chip storage
- Day hopper
- Stoker
- Air cooled grate
- Ash removal and storage
- Hot air heat exchanger
- Electrical and instrumentation

H.V. of Fuel: 19.7 GJ/ODT wood

Moisture Content 43% dry basis

Daily Fuel Input 2 6 ODT wood

Furnace Efficiency 0 70

250°C stack gas temperature. This relatively high thermal efficiency is partly a result of suspension burning, where a high heat release rate (comparable to oil- or gas-fired boilers) is achieved. A sample suspension burner system is shown in Exhibit 16.10. Some manufacturers claim good suspension burning efficiency for fuel up to 30 percent moisture content and 12-mm maximum diameter. A reasonable set of limits is a maximum of 15 percent moisture content (wet basis) and 6-mm maximum dimension for suspension burning.

Suspension burners must be equipped with a flame safeguard device (such as "Fireye" by AC Controls) because very fine, dry fuel has a high explosion potential. The essential element in such a burner, other than fuel quality, is the control of the amount of combustion air and its turbulence. In suspension burning, too much or too little excess air will affect the completeness of combustion in a disproportionate manner. Likewise, ensuring violent turbulence and mixing throughout the burning area is most important. Impellers and turning vanes are used to ensure fuel/air mixing. Excess air of from 15 to 50 percent is appropriate, depending on fuel quality.

Fluidized-Bed Systems

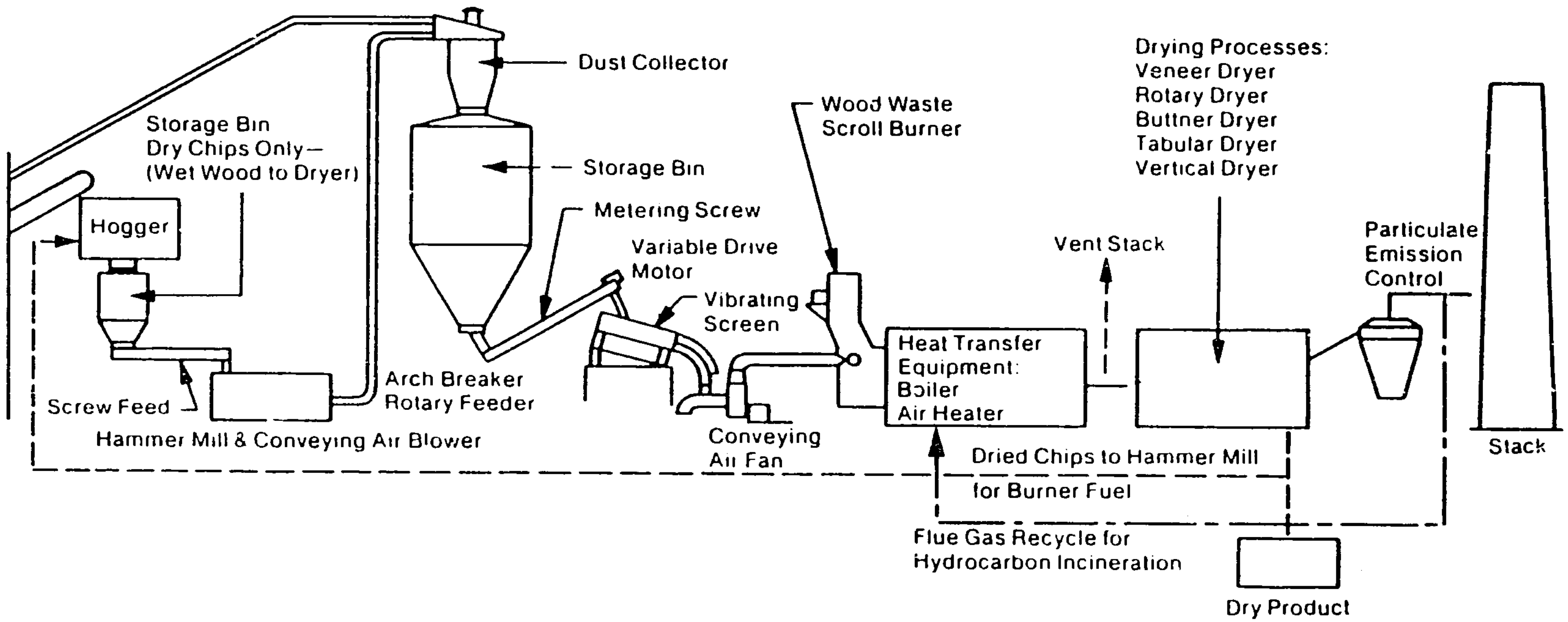
Fluidized-bed combustion systems burn fuels (gas, liquids, or solids) in the presence of a mass of mineral particles (i.e., crushed sand, limestone, dolomite, or other materials) that are supported and kept in turbulent motion by a constant stream of air. There are two basic types of fluidized-bed combustion systems: atmospheric and pressurized.

The fluidized-bed package boiler is an atmospheric combustion system. Combustion air passes through a bed of lime, fuel (e.g., wood waste), and ash particles in a homogeneously turbulent motion that closely resembles a boiling liquid. This turbulent motion results in a five- to tenfold increase in the heat transfer rate within the bed when compared with a conventional stoker-fired boiler. The atmospheric multifuel fluidized-bed combustion package system can be used to produce steam or hot water, and operates at an efficiency of between 65 to 75 percent, depending on system design and fuel characteristics.

Wood-fired fluidized-bed combustion systems are commercially proven for systems producing up to 5 tonnes of steam per hour and have been demonstrated up to 25 tonnes

Exhibit 16.10

Wood Waste Conversion System Using Suspension Burner



per hour. A 50 tonnes/hr unit manufactured by Combustion Power Company is in operation at the Weyerhauser facility in Longview, Washington (United States). The unit burns log-yard cleanup and other residues to provide hot gas to a boiler. All existing units are firetube construction and are therefore limited to about 20 bar pressure.

SYSTEM SELECTION

Exhibit 16.11 summarizes the typical concerns of the user and the characteristics of the various types of equipment. The ratings for each type of boiler/burner are given as a guide to the user. The ratings for a particular system are relative to ratings for other systems under the same general heading. Thus, steam generators should not be compared with direct-fired applications. A knowledge of fuel type and energy load patterns will enable the user to determine which boiler/burner systems are suitable for his particular situation.

In some cases, it is appropriate to use hot air rather than steam as the heat transfer medium, which allows the user to avoid the capital charges associated with a pressure vessel. Wood-fired units are available for this purpose. In such units, the same factors should be weighed as for steam generators regarding firebox design (refractory, air flow, heat release rates), fuel and ash handling, and degree of automation.

Fully automated industrial heaters will be priced at from $10,000 to $30,000 per GJ/hr of output. Additional capital investments of up to $20,000 per GJ/hr output may be required for unloading and storage when fuel is purchased on the open market.

As with steam generators, economic analysis is very dependent upon fuel costs and degree of utilization of full capacity. Additionally, the efficiency of these units is difficult to predict, measure, and control, although the practical combustion efficiency can be slightly better than for a medium-pressure boiler. Manufacturers' claims as to output and operating characteristics should always be correlated with fuel quality characteristics (higher heating value, moisture content, and ash).

Exhibit 16.11

Comparative Performance Ratings[1] for Various Wood Combustion Systems

	History of industrial service	Compatibility with wet or unsized fuel	Ease and cost of operation	Ease and cost of maintenance	Steam pressure or gas temperature available	Response to load changes	Turndown ratio	Capital cost	Environmental impact
Steam generators									
Firetube boilers (HRT)									
Suspension burners	B	P	G	B	G	G	G	B	G
Grate burning (spreader stoker)	G	G	F	F	F	P	G	G	F
Pile burning (dutch oven or retort)	G	F	F	F	F	P	F	G	F
Watertube boilers									
Suspension burners	G	P	G	F	B	B	G	B	G
Grate burning	G	G	G	F	B	F	F	F	F
Pile burning	G	F	G	F	G	P	P	P	P
Gasifiers	U	P	U	U	F	U	U	U	B
Fluidized-bed burners	F	B	G	F	F	G	F	G	F
External furnaces	F	G	G	G	F	F	F	F	F
Direct-fired application									
Suspension burners	F	P	P	F	G	G	G	B	G
Fluidized-bed burners	P	B	F	F	F	G	F	G	F
Gasifiers	U	P	U	U	F	U	U	U	B

[1]The ratings for a particular system are relative to other systems under the same major use heading (steam generators or direct-fired applications): B = best; G = good; F = fair; P = poor; U = unknown.

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Some industrial processes require high-temperature fluids that are best provided by hot oil heaters (e.g., Dowtherm systems). At least one manufacturer will provide a wood-fired, hot oil system. Since a wood furnace will necessarily be less responsive than an oil or gas furnace to sudden thermal load changes, and since thermal fluid temperature is usually critical to the process, the design of the hot oil flow system must accommodate this unique limitation.

RETROFITTING FOSSIL-FUELED BOILERS

As the costs of fossil fuels have risen between 1973 and 1981, more and more operators of industrial plants have considered switching from oil to other fuels for firing their boilers. Plant operators in the forest products industry were the first to make the switch in significant numbers when they began to recognize the value of the wood residue (shavings, sawdust, bark, and other waste) they had been incinerating. The drying of finished lumber had often been accomplished by direct firing of lumber kilns, but it can also be accomplished using steam radiators supplied by a boiler. The boiler may have been fired with oil or gas as well, but it could be replaced by a wood boiler. However, the replacement of an existing gas or oil package boiler that has significant useful life remaining can be an unattractive task, especially since the scrap value of the boiler will be far below what the boiler is worth to the lumber operation.

Cyclone Burners

Forest products plants (including furniture manufacturing plants) began to use cyclone and suspension burners to burn wood in their existing boilers back in the 1940s. The major drawbacks to these burners are that the **fuel must be of a low moisture content** (less than 15 percent) **and of a uniformly small size to operate properly**. This type of fuel may be available to the forest products plant but will rarely be available (on a long-term basis) to the non-forest-related industrial plant. When the cyclone burner is retrofitted, the existing gas or oil burner is removed and the boiler wall is modified to receive the wood burner. Since most cyclone burners use refractory furnaces for combustion, the radiation component of the flame will be largely lost; also, the necessity for firing with higher excess air levels will result in at least a 20-percent derating of the existing boiler.

The derating may not be a serious problem if the boiler is seldom run at full capacity. If necessary, an auxiliary fossil-fuel burner can be used to make up for the derating.

Fluidized-Bed Burners

Fluidized beds have been a popular topic over the past few years, and there are several firms actively marketing wood-fired fluidized-bed boilers in the United States today. Most of these firms want to sell a complete package consisting of a fluidized-bed combustor and an integral boiler or a close-coupled boiler of the waste heat variety, but it may be possible to consider the retrofit of an existing oil-fired boiler. Some radiant heating of the boiler will be lost, resulting in a derating of the unit. Some of this loss might be made up by running boiler tubes through the fluid bed where the heat transfer rates are reportedly quite high. While this retrofit concept is quite interesting, there is only one commercial unit operating in this country at present.

Particulate emissions from such a fluidized bed will be substantially higher than from an oil flame, requiring the addition of a particulate collection device at the boiler exit to collect unburned carbon, fly ash, and any bed material entrained in the flue gas. The advantage of a fluidized-bed burner is that it will operate with wood fuel up to 55 percent moisture content.

External Furnace

The "Conifer" burner, marketed by the American Fyr-Feeder Company, has been retrofitted to existing fossil fuel boilers. The system consists of a sloping grate combustor with two-stage air introduction that operates like a semi-gasifier. Such a combustor has been fitted to an existing 60 tonnes of steam/hr pulverized-coal boiler at a Midwest paper mill in the United States. The Conifer burner supplies 20 tonnes of steam/hr, and the remainder of the load is picked up by the cyclone coal furnaces. It is conceivable that an existing small gas or oil boiler could be retrofitted with this type of combustor.

ECONOMIC CONSIDERATIONS OF WOOD FUEL USE

The economic feasibility of a wood energy project depends on several interacting variables. As in the case of coal (see Session 15), these variables primarily include the cost of fuel, capital investment requirements, and operating costs. Special legal and financial considerations and the physical availability of fuel should also be considered.

The Cost of Fuel

The price of wood fuel is generally no more or less predictable than the price of other fuels. Whether it is obtained directly from the forest or as a byproduct of manufacturing processes, wood fuel is subject to the fluctuations of the market place.

The price or value of wood fuel is usually stated in monetary units per ton. Since wood of different species and moisture content has different energy content, it is convenient to state this value as dollars per million kcal. To be even more accurate, we should take into account the conversion efficiency of various combinations of fuel type and conversion equipment and state the value as dollars per million kcal converted to steam (or as hot gas, or as electricity, etc.). Exhibit 16.12 compares the cost of energy from various wood and fossil fuels in the United States in 1980. The effects of moisture content on the heat value and combustion efficiency of wood have been discussed in earlier sections.

In general, three physical considerations dictate the effective fuel price:

1. Some or all of the wood fuel may be derived from in-plant sources.
2. Some or all of the fuel may be obtained from external sources.
3. The energy value of the wood fuel, as well as the appropriate conversion equipment for that fuel, is dictated primarily by the moisture content of the fuel.

Exhibit 16.12

Comparison of Net Energy Available from Wood and Fossil Fuels on a Cost Basis*
(1980 basis)

Fuel	Assumed cost per unit (dollars)	Assumed combustion efficiency	Estimated high heating value (GJ per unit)	Calculated** dollars per GJ
Coal (2.5% MC)	54.28/ton	0.825	27.4	2.46
Fuel oil	0.60/gal	0.80	0.16	4.69
Wood pellets (10% MC)	35.00/ton	0.778	17.9	2.54
Wood chips (47% MC)	12.00/ton	0.67	17.9	1.89
Green wood residues (47% MC)	8.00/ton	0.67	17.9	1.26

*Figures should be used as examples; they may not be representative of today's prices.

**Dollars/GJ = cost per unit/(high heating value x combustion efficiency x (1 - MC/100)).

In-Plant Fuel

The first case, in-plant sources of fuel, is the simplest case. In this situation, the cost of fuel is the selling price that would be realized if the byproduct were sold. Economists call this the "opportunity cost." Depending on the type of fuel and the plant location, this opportunity cost can range from about -$1/ton to +$3/ton for furniture residues, sawdust, and bark. The negative value represents money paid to haul it away or to incinerate it.

Another type of opportunity cost arises where existing boilers are used as incinerators to dispose of manufacturing waste. This is common in hot weather for furniture plants and in some sawmills. The hidden cost of such incineration is found in electrical energy for fans and pumps, labor, physical depreciation of equipment, and water treatment costs (very high where steam is vented and condensate is thus lost). This opportunity cost, which is always negative, should be considered. For example, if 20 tons/day of dry fuel are burned in a 400-hp boiler and the steam is vented, the operating costs (labor, electricity, and depreciation) will be about $40. In other words, this is an opportunity cost of -$2/ton.

Purchased Fuel

Purchased fuel may originate in a manufacturing plant or a harvest site. As with in-plant waste, it will range from kiln-dried material at 8 percent moisture content to wet material at about 50 percent moisture content.

Manufacturing wastes may cost -$0.80 to +$2.40/ton, plus about $0.04 to $0.08 per ton-mile in 40-foot trailers; smaller loads will require the higher rates. Wood fuel from the forest may be from about $8 to $12/ton in trailers delivered to the user as whole tree chips. Pelletized wood, a type of processed fuel, may be about $24/ton plus freight.

All these purchased products will be sensitive to the cost of fuel oil used in transportation. A trailer truck loaded with 25 tonnes of wood fuel will use about 4 liters per 6.5 kilometers and will use about 4 liters per 10 kilometers when returning empty.

Economic Effects of Moisture Content

Moisture content affects energy economics in three ways:

1. To the degree that moisture is present, each ton of wood contains less than a ton of dry fuel.
2. To the degree that moisture is present, a part of that dry fuel is used to evaporate that moisture and to superheat it to the exhaust gas temperature (as was demonstrated by the boiler efficiency figures in Exhibit 16.12).
3. Moisture content of the fuel dictates the feasibility of certain types of handling and burning equipment.

Capital Investment

The capital investment by the user includes:

1. Unloading equipment (where required)
2. Fuel processing equipment (where required or desired)
3. Storage capacity, with retrieval equipment
4. The energy conversion unit (e.g., a boiler and its auxiliary equipment)
5. Pollution abatement equipment (as required)
6. Control systems for all of the above.

The configurations and prices of the above items were discussed in preceding paragraphs. In brief, such integrated systems can be installed for prices ranging from \$20,000 to \$200,000 per tonne of steam/hr (tsh) output capacity. The higher price indicates a more automated and sophisticated system.

A price of $1.4-2 million for an installed 25-tsh boiler and its auxiliary equipment is typical. This would include a high technology boiler to burn wet bark, and controls and equipment for pollution abatement. It would include limited fuel storage, but no fuel unloading equipment, nor secondary emission controls, nor long-term storage. A 2-tsh boiler in a similar configuration would cost about $200,00-$300,000.

The even higher investment of up to $200,000 per tsh corresponds either to smaller units that use maximum automation or to much larger units that must accommodate purchased fuel, with truck dumps and large fuel storage shelters, and that require more elaborate pollution abatement controls.

In addition, for a given energy output, dry fuel will require less investment in the energy conversion unit but more investment in fuel storage than will be the case for wet fuel.

These capital costs will vary widely from one type of boiler to another. They will also show greater variation as manual labor is substituted for automation. This is especially true at the lower end of the system capacity range. In any case, vendor quotes for each particular application must be used. For a given boiler capacity, cost may vary between plus/minus 50 percent, depending on the site conditions.

Labor Requirements

A wood-fired unit will require more operator attention than an equivalent capacity oil or gas unit, owing to the storage and feeding characteristics of wood fuel and the variable ash and combustion characteristics of wood. The labor requirements of any such system are mostly dependent on two conditions:

1. The fuel quality -- specifically, the particle size, ash, and moisture content
2. The degree of automation of the storage, feeding, and burning equipment.

Where the **fuel is dry and finely ground**, as with hogged furniture waste or sander dust, the burning characteristics approach those of oil. In these cases, automatic controls function well, and the full-time attention of an operator is usually not required.

Where the **fuel is wet and/or non-uniform in size,** more operator attention is required. In these cases, the operator must maintain a proper char bed depth, adjust for excessive moisture, remove ash, and monitor the operation of fuel feeding equipment.

Insurance requirements and local codes will vary for each plant. Exhibit 16.13 illustrates typical industry practice regarding operator and supervisor requirements.

Other Operating Costs

When compared to oil-fired systems, the major incremental costs of a wood system (other than labor) are due to increased use of electrical power and to increased maintenance charges. When compared with coal fuel units, the other operating costs are about the same. Maintenance costs for a wood-fired system will be about 200 percent of those for a comparable oil fired system.

For new units of more than approximately 5 tsh output, pollution abatement regulations will require the use of mechanical cyclone collectors, which in turn requires the use of an induced draft fan. A boiler of 5 tsh capacity or greater would require a fan motor of approximately 20 hp output. Assuming 95 percent efficiency, 80 percent average load, operation 24 hours per day and 360 days per year, and $0.04/kWh net cost of electricity, then the incremental electrical cost would be about $4,000.

There would also be incremental electrical costs for fuel handling and for incremental forced draft (excess air). This cost would be less than $520/yr for a system of less than 10 tsh boiler output.

RECOMMENDATIONS

In a wood products plant, managers should conduct a financial analysis to study the feasibility of burning all the available excess wood waste. This analysis should consider such options as electrical generation and selling steam to nearby plants. The managers should also consider the purchase of wood fuel during periods of steam demand in

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Exhibit 16.13

Typical Operator and Supervisor Requirements

		Operator requirements by fuel type (per shift)	
Size (tsh)	Degree of automation	Dry, hogged	Green, rough
0.1-0.5	High	1/4-1/2	1/2
	Low	1/2	1
0.5-50	High	1 with other duties	1
	Low	1	1 + 1/2 supervisor
over 50		1 + day supervisor	2 + day supervisor

excess of boiler capacity, which may entail the installation of new equipment to burn whole tree chips or other wet wood fuels.

<u>**For other industries,**</u> managers should consider the purchase of steam or wood fuel from wood products plants, or wood fuel from whole tree chippers. This last option may not be economically feasible for the small user.

For any case, the oil units could be left in place or replaced with multi-fuel units. Thus, the user would be able to enjoy the security of diverse fuels and derive the financial benefits of low-cost wood fuel.

In some cases, the most attractive energy investment alternative for small users may be a <u>**combination of neighboring plants**</u> or companies to maximize the use of wood fuel and wood fuel-burning equipment while minimizing the resources devoted to fuel transportation and storage.

Convert boiler to burn bark . . .

thus saving oil in this mill's bark/oil-fired power unit. Economics will look even better as oil prices rise and boiler is more fully utilized to meet a larger steam demand

By **B F Morgan**, H A Simons Ltd, and **R Mills**, Boise Cascade Ltd

In October 1979, Boise Cascade Canada Ltd commenced firing bark in a low-odor recovery boiler converted to a traveling-grate bark/oil-fired unit capable of producing 290,000 lb/hr of steam when firing oil only, and 253,000 lb/hr of steam when firing bark only. The boiler is at Boise Cascade's pulp and paper mill in Newcastle, New Brunswick, Canada (Fig 1).

Poor operation (see box) led to the decision to install proper oil guns, combustion control, and a boiler master on the recovery unit, now called power boiler 4. Following this, the logical conclusion was to convert the unit to bark/oil firing. It would be the only power boiler at the Newcastle plant, at least during the summer months. Simons Tecsult of Montreal was retained as consultant on all phases of the project.

Conversion phases

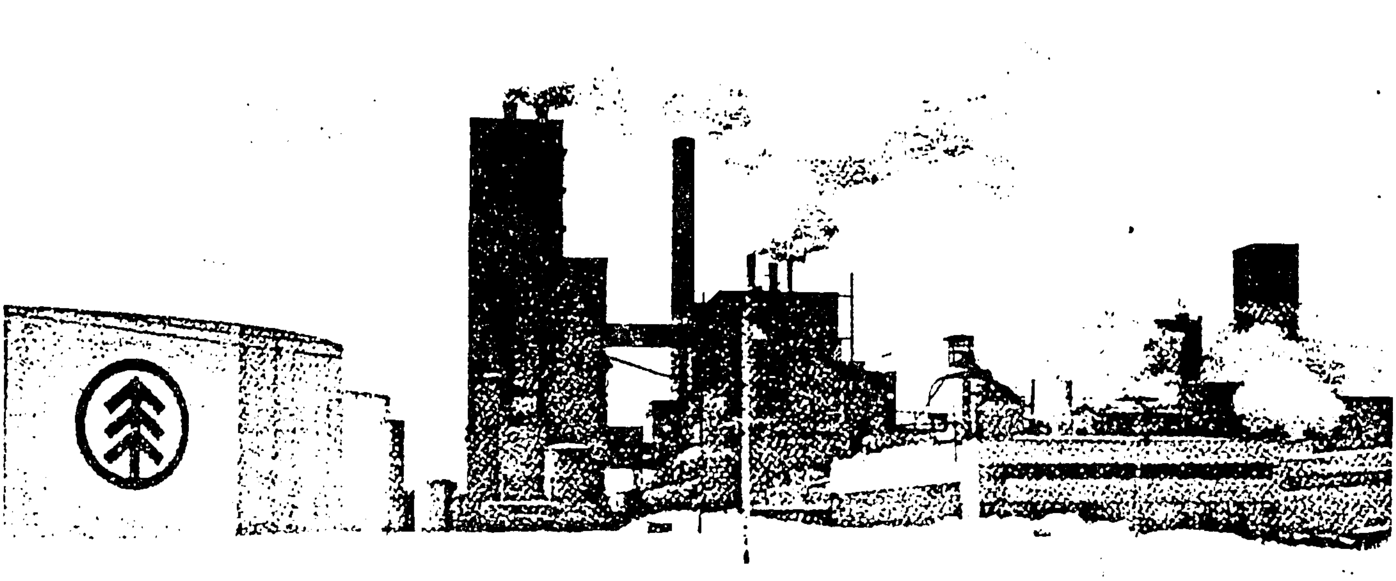
It was necessary to split the conversion into two phases to minimize the impact on mill production. As phase 1, the oil-burning equipment was installed between January and March 1979, with startup March 18. As phase 2, the grates, induced-draft fan, dust collector, and other additions were completed between July and September 1979, when steam demand was reduced to the point where power boiler 4 could be removed from service.

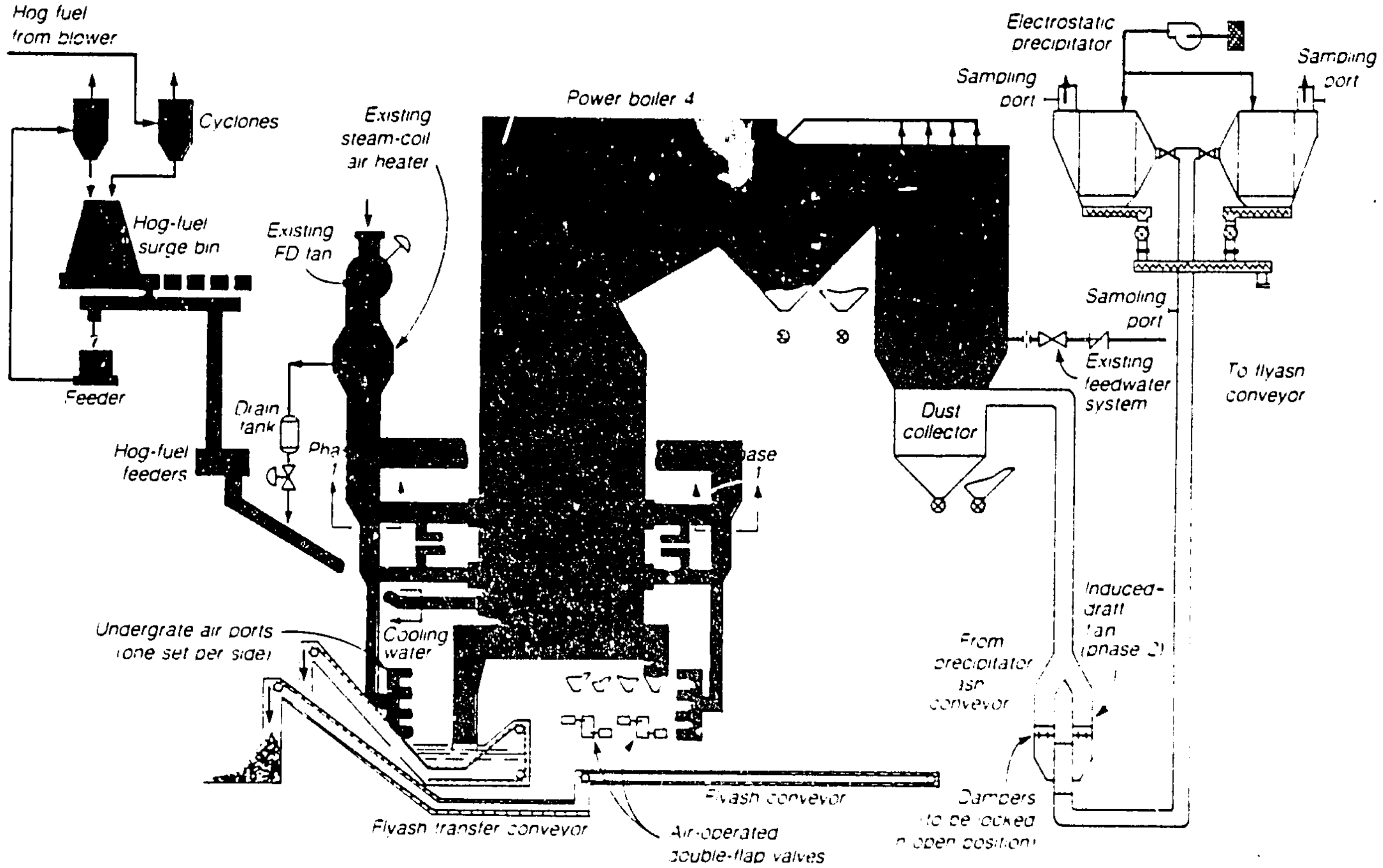
Burners and dampers. Four tangentially fired, retractable, tilting burners were added. Each burner has a 5:1 turndown and is capable of firing 695 gal/hr of oil at 200 psig. Because of the external mix feature, only 75-psig atomizing steam pressure is required. Angles on the tips were changed from 90 deg to 60 deg to prevent the flames from impinging on the tubes. Four 4-million-Btu eddy-plate ignitors using propane with lime-light flame scanning and a separate air supply can input enough heat to light off the burners safely at a zero tilt position. Fig 2 shows the bark-burning system.

An automated burner system provides safe monitoring of individual burner flames without the need for continuous propane ignition. Flexible flicker sensors using fiber-optic cables and lens assemblies discriminate regardless of tilt position. Burners are added or removed from service via a remote operator interface located on the boiler panel. The firing panel consists of a common operator interface and a first-out annunciator. A control system regulates feedwater flow, furnace draft, steam temperature (burner tilts), combustion, and load level.

The air supply to each burner is controlled with three dampers—top, center, and bottom—per side. The center one is activated by the burner system, with the damper of both the gun in service and its opposite being opened a predetermined amount when either gun is started, thus meeting safe light-off air requirements.

1. **Pulp and paper mill** at Newcastle in Canada was switched to a multigrade operation





2. Boiler conversion is centered around a bark-burning system to accommodate a range of wood characteristics

Regulation of the center and lower auxiliary dampers is released to the control system once a flame is established. The center dampers of the opposite guns will modulate only on the burners in service.

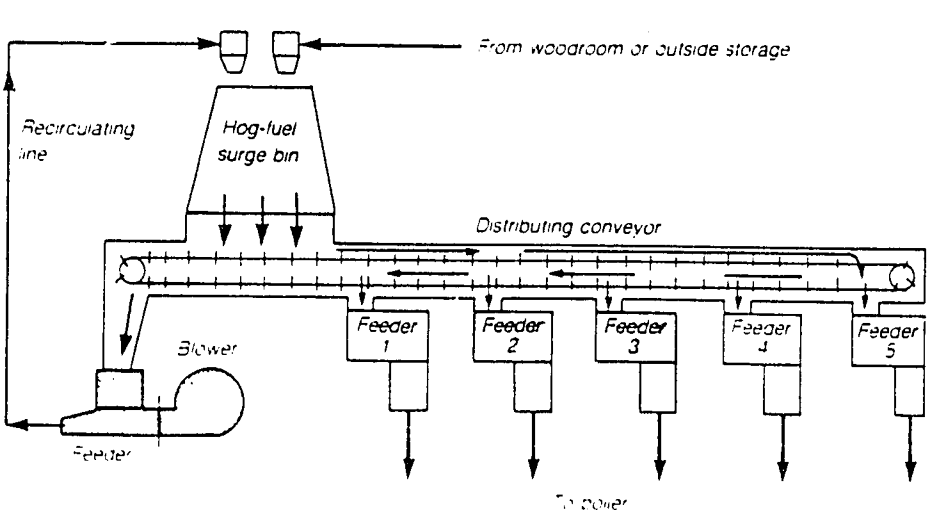
The top auxiliary air damper is strictly manual and is closed at all loads. Currently, in fact, the center dampers at full load are only 30% open with the lower dampers shut.

This control/oil-burner combination yields reliable operation at 290,000 lb/hr, 750F, and 600 psig on oil only, with a 25-deg up-tilt. The burner tilts start to control temperature once a 180,000-lb/hr load is reached.

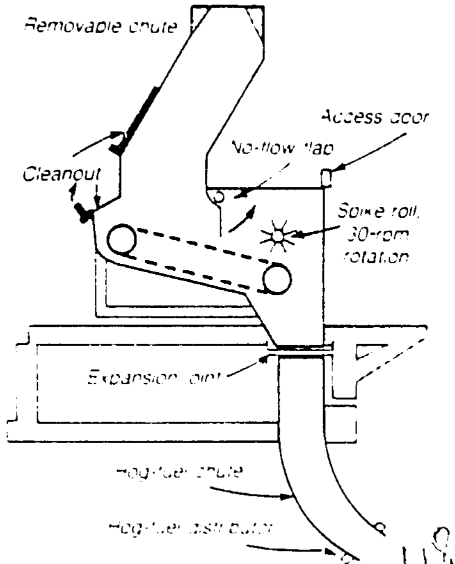
Two traveling grates, 10 ft wide × 24½ ft long, were added, each with an effective grate area of 245 sq ft. They are capable of producing a maximum of 253,000 lb/hr of steam on hog fuel only, with a grate heat release of less than 850,000 Btu/hr-sq ft and 20% firing in suspension. Furnace residence time is about five seconds, which provides good char burnout and minimum carryover.

The traveling type of grate was selected for its automatic ash removal and low thermal inertia. These characteristics assure maximum hog-fuel burning over a 24-hr period. Steady bark feeding, grate-temperature monitoring, proper lubrication, and learning from the experience of others has reduced the high maintenance incurred on a number of earlier traveling-grate installations. Also, the use of 300F undergrate air and the safe application of the tilting burners has eliminated grate overheating.

3. Boiler-feed system moves hog fuel from surge bin, through stokers, to boiler. Five variable-speed feeders channel fuel to chutes equipped with mechanical stokers



4. Hog-fuel feeder has variable-speed drive to provide continuous, uniform flow



The grate-drive system is capable of varying grate speed from 2 to 20 ft/hr. The grate must be run continuously to prevent damage even when no bark is being burned.

A new induced-draft (ID) fan was provided, driven by a 1000-hp 757-V wound-rotor motor. ID-fan inlet and outlet ducts were fabricated in one piece, then insulated and lagged to fit the confined area available.

A new dust collector located before the ID fan and electrostatic precipitator removes 75% of the flyash. Extensive repairs were made to the existing precipitator to return the unit to its original condition and achieve an estimated removal efficiency of 92%.

Overfire and undergrate air ducts were installed. Total wood/air control dampers, one per side, are modulated to control air to bark. Overfire ports are tangential, and each of the four ports has three dampers. The center damper remains closed when firing bark. The bottom damper modulates to full open depending on the bark-firing rate. The upper damper modulates to full open after the lower damper is fully opened, also depending on bark/air requirements. The two modulating dampers can be used to trim excess air.

Undergrate dampers, four per side, are set manually to regulate air to compartments. This feature permits optimizing stoker operation to compensate for various air requirements as the fuel bed moves through the furnace. The dampers are modulated to ratio undergrate to overfire air at roughly 50/50.

The forced-draft fan is capable of supplying air at 6-in.-H_2O pressure to both oil/air and bark overfire air dampers. The boiler trip is set at 3-in.-H_2O air-duct pressure. The original FD-fan capacity was increased about 30% by adding fan tips and increasing the motor size.

Boiler-feed system. The surge bin, 18 ft long × 16 ft wide × 27 ft high, is equipped with two pushers, each with its own independent hydraulic system to push bark onto a drag conveyor (Fig 3). Five variable-speed feeders (Fig 4) direct hog fuel to five chutes equipped with mechanical stokers. Excess hog fuel is recycled to the surge bin using a feeder-blower. With this arrangement, it is possible to provide a continuous and uniform hog feed, one responsive to signals from the hog-fuel master whose steam demand, in turn, is set by a feedforward signal from the plant master. The hog-fuel master controls feeder speed via the variable-speed drives.

In addition, the boiler has an oil-fuel master or demand controller which will react should the hog-fuel master not be able to respond, either because of a steam from hog high-limit or a shortage of hog fuel. To date, the feeders have given a relatively uniform feed to 250,000 lb/hr of steam with hog-fuel firing, yielding steady steam and feedwater control with no oil firing.

Grate ash is discharged into a submerged conveyor. Grate siftings, plus ash from boiler hoppers, dust collectors, and precipitators, mix with wet grate ash on the inclined portion of the dry-ash transfer conveyor (Fig 2). The resulting ash mixture is discharged to a concrete bin, for removal to a disposal site every 48 hours. Fog nozzles have been added at dry-ash transfer points and on the flyash transfer conveyor to eliminate severe dusting problems following startup.

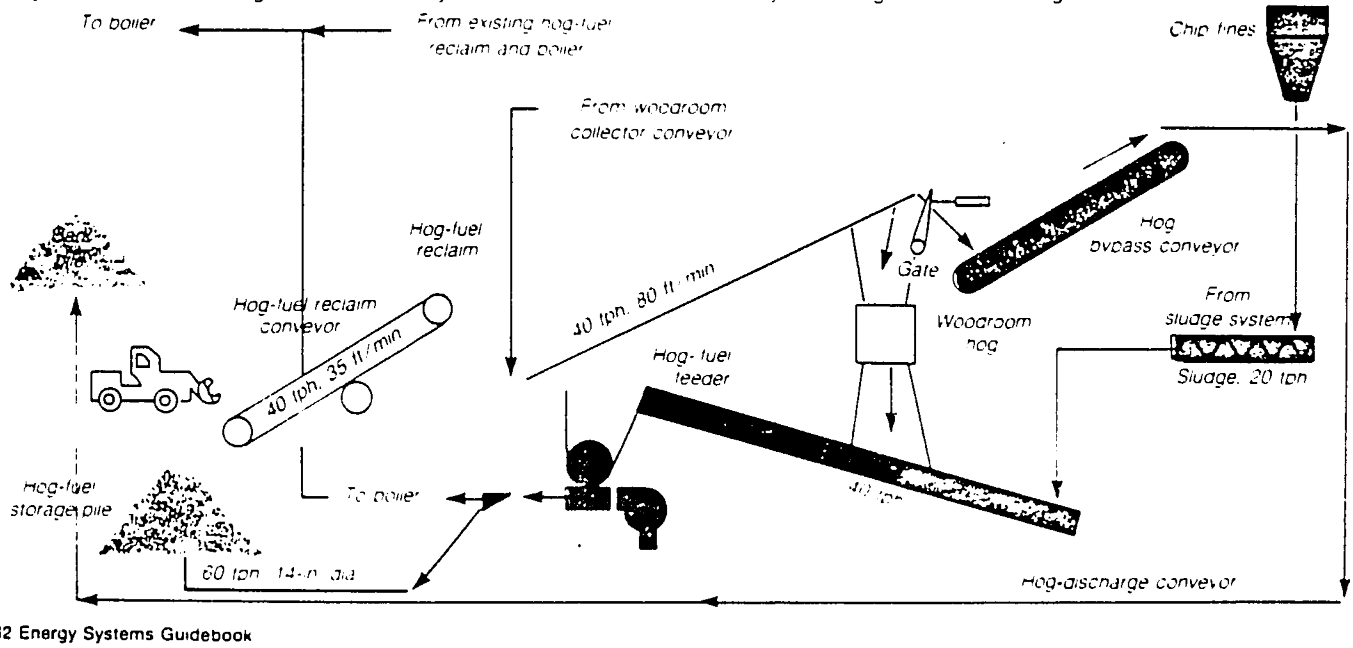
Bark preparation. The woodroom contains the hog-fuel preparation system (Fig 5). Bark is discharged from three dry-drum debarkers onto a conveyor feeding a hammer hog. The hogged fuel is mixed with pressed sludge and chip fines, which can be blown either to the steam plant or to a hog-fuel storage pile for eventual reclaim. No hog press is required because of the new dry debarking system.

Making a commitment at Newcastle

For economic reasons, a decision was made in 1977 to reduce the pulp and paper mill at Boise Cascade's Newcastle operation from a two-line 700 tons/day output (480 tons bleached, 220 tons unbleached) to one 535 tons/day multigrade mill. In December 1977 the mill became wholly owned by Boise Cascade. With this change came a commitment to provide the capital necessary to make the Newcastle operation a viable and profitable one.

With the mill cut back, a spare 1972-vintage, 1.2-million lb/day of solids, low-odor boiler remained, which was capable of producing 188,000 lb/hr of steam at 750F and 600 psig—considerably below the design pressure of 775 psig. The unit was retired as a recovery boiler in December 1977, and until December 1978 it was used as a base-loaded power boiler with poor combustion efficiency, only 600F exit steam temperature, and a maximum capacity of only 160,000 lb/hr because of oil-burner limitations.

5. Woodroom bark is fed to hammer hog, from which hogged fuel is mixed with sludge and fines, then sent to boiler or storage. Initially, the bark is discharged from three dry-drum debarkers onto a conveyor feeding the hammer hog



The sludge preparation system (Fig 6) consists of a vacuum-coil filter with a discharge consistency of 20%, and a hydraulically loaded and driven-roll sludge press which yields a 35% consistency. Chip fines from a cyclone are mixed with the pressed sludge before both drop onto a conveyor to be mixed with hogged fuel. The sludge can also be discharged to outside storage, bypassing the sludge press.

Savings and expectations

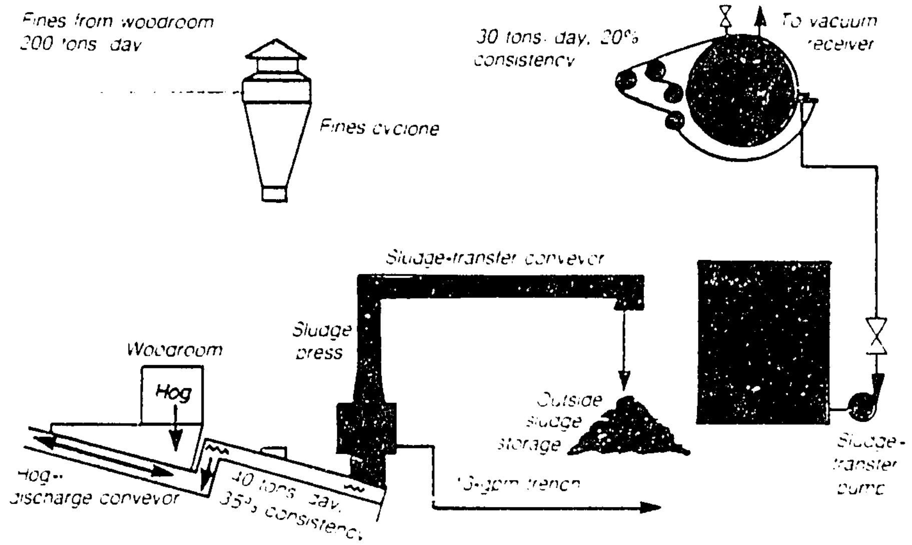
Power boiler 4 has been capable of carrying mill steam demand on hog fuel only for periods over 14 hours with acceptable header-pressure control. The limitation has been the hog-fuel recirculation feeder, which is occasionally jammed by rocks and pieces of metal.

The impact of hog-fuel burning on purchased oil has been substantial. For 1980, oil consumption was reduced by 41.5%, leading to oil savings of 140,000 bbl. With improvements, a 60% oil reduction is anticipated, which would yield annual oil savings in excess of $4-million.

To better capitalize on power boiler 4's hog-fuel-burning potential, it is expected that hog fuel will be purchased from sources further away, and options such as local chipping of brush and hardwood will be considered. Also, some revisions will be necessary to improve hog-fuel-system availability and unit efficiency to sustain high steam loads of 225,000 lb/hr from hog fuel only.

A hog-fuel-preparation system capable of removing all rocks, metal, and other extraneous material may be required. This system might pass all hog fuel through a disc screen, with only the oversize rejects being hogged, thus reducing the load on the existing hog. The method of hog-fuel transfer to the surge bin will be investigated to improve its capacity and availability. Recirculation-system capacity may also be increased. ■

6. Sludge preparation relies on filter and press to concentrate sludge for reuse. Filter has discharge consistency of 20%, press gives 35% consistency



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SESSION 17: WASTE BURNING

Because most so-called waste fuels available are of vegetable origin, this session will focus on biomass waste fuels. Combustion of biomass waste fuels such as bark and sawdust is very similar to that of wood, which was discussed extensively in the previous session. Consequently, this session will focus first on the fuel handling and storage of, and differences between, wet (green) and dry wastes. Next, a series of articles will present the combustion characteristics of other types of industrial wastes that could become relevant.

FUEL STORAGE: BARK, SAWDUST, CHIPS, AND OTHER GREEN RESIDUES*

Bulk storage of wood or bark particles is not new to industry. The pulp and paper industry for years has inventoried in storage yards thousands of tons of green wood chips as a pulp furnish. Recently, the high cost of electric energy and fossil fuels has forced many industries to return to wood as a fuel, and the wood products industry is logically the first to convert.

To maintain a continuous fuel supply and meet peak load demands, wood fuel is often inventoried. Exhibit 17.1 shows the estimated storage volumes for several boiler sizes and inventories. A 20-GJ/hour system could require between 80 and 150 green tons of fuel in a 24-hour day.

Fuel storage techniques can best be characterized as trial-and-error coupled with convenience and low cost. Green wood particles are predominantly piled outside, because protecting already-wet material from the elements serves no apparent purpose. Storage cost is only the carrying cost of the wood and the real estate on which the wood is stored. Piles are generally shaped according to the delivery system, with the emphasis on higher piles because of limited storage areas and high cost of land.

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*This section has been adapted from publications of the U.S. Solar Energy Research Institute.

Exhibit 17.1

Estimated 5- to 30-Day Storage Volumes for 5, 10, and 20 GJ/Hr Conversion Systems Operating at 67-Percent Efficiency

Conversion system (GJ/hr)	Days inventory					
	5		10		30	
	m^3	tons	m^3	tons	m^3	tons
5	250	95	500	190	1,500	570
10	500	190	1,000	380	3,000	1,140
20	1,000	380	2,000	760	6,000	2,280

Assuming whole tree chips with a higher heating value of 19,730 kJ/kg, moisture content 50 percent, and bulk density.

Studies have shown that the moisture content and heat of combustion of wood particles change during storage. Research into storage effects has increased worldwide in recent years because of the pulp and paper industry's interest in inventorying furnish for its mills. The emphasis in these studies has been on fiber losses during storage and subsequent effects on pulping yields. The spontaneous heating that occurs within large piles of green wood or bark often causes fires. The chemistry within these piles is complex and changing and causes degradation and fiber loss.

Effect of Pile Geometry on Open Storage of Green Woody Particles

A pile with steep sloping sides sheds rainwater. Rainwater will percolate into flat piles and actually cause a net gain of 44 percent (80 percent moisture dry basis) in the moisture content of the wood particles from the green condition.

The moisture content changes from the outside to the inside of a cone-shaped and flat pile after 5 months' storage, but the flat pile changes little. In the taller piles, the "skin" of the pile changes daily; the outer 300 mm just below the skin actually gains moisture and remains saturated throughout the storage cycle. However, the bulk of the cone-shaped pile dries, depending on the material in it.

Pine bark dries in 30 days to fiber saturation point; sawdust dries more slowly. A mixture of the wet outer material and the dry inner material is the best boiler feed. Such a mixture reduces the average moisture content and prevents flame-out caused by overfeeding a concentration of saturated surface fuel.

Windrow construction of piles is ideal because these piles incorporate sloping sides with maximum storage volume. The precise layout of windrows depends on the infeed and retrieval system in use. Windrowed piles are readily adaptable to overhead conveyor infeeds and underfeed retrieval systems.

The size of piles is determined primarily by the pile height, given a natural angle of repose. Higher piles allow more material to be stored in a given area. However, the risk of incidence of spontaneous fires in bark piles increases with pile heights above 5 meters. When turnaround times are more than 4 weeks, piles should be kept below this maximum level for safety reasons. Piles of predominantly wood particles can be stored longer in higher piles.

The Effect of Pile Contents

Initial indications are that both temperature increases and moisture losses occur more rapidly in bark (both hardwood and pine) than in wood particles (either sawdust or chips). Initial degradation is probably higher in bark piles. Maximum temperatures are generally found between one-third and one-half of the way down from the top of the piles. Over time, all piles tend to reach a common threshold or equilibrium temperature. Pine bark reaches this 77°C-88°C threshold in 2 to 3 weeks. Hardwood bark takes longer, perhaps because of the flat nature of the pile.

Because of this rapid heating in bark, caution must be exercised to prevent fires. Spontaneous fires in storage piles of wood and bark particles require (1) a heat source from within the pile, and (2) oxygen, which comes from outside. A common starting point for fires is near the surface of the pile in cracks or openings that permit oxygen to reach the hot interior; most fires do not start in the internal hot zones.

One long-used preventive is to compact piles with heavy equipment. This method reduces the oxygen supply to the interior of the pile but is not compatible with proposed spontaneous drying pile geometries outlined in the previous section.

For storage periods longer than 6 months, fires may be a hazard in any residue pile. Actions to minimize this risk include developing a first in/first out storage and retrieval system and forming a windrow 4 to 5 meters high and of any length desired. The windrow should have a flat top wider than that of the front-end loader and should begin at a point most accessible to a front-end loader or retrieval system. The retrieval system should remove from the accessible end down the center of the pile, forming two small windrows that can be removed as needed.

Generally, a piling system effective in retarding heat build-up enhances moisture build-up. A storage pile in windrow form with a peak down the center would facilitate internal drying. This pile must be monitored closely for temperature changes that may cause fires.

To avoid the risks mentioned above to the extent possible, the following recommendations should be followed:

- Reduce the likelihood of fires started by external stimuli by observing certain safety precaustions. Keep cigarette butts, matches, sparks, hot metal, oil, or open flame away from bark or sawdust piles.
- Construct piles on a noncombustible thermal conducting surface. Common soils appear to be quite inadequate. If cleanliness is desired, a dark-colored masonry surface may be considered.
- If practical, install heat exchangers in the pile to remove heat from the base of the pile.
- Larger and higher piles are a greater fire hazard; therefore, green bark piles stored for more than 30 days should be kept to a maximum height of 5 meters.
- Piles should be ventilated to allow heat to dissipate:
  - piles should be shaped to permit rapid ventilation when needed
  - any build-up of fines on the pile surface must be dislodged to allow heat to escape.
- Small bark particles pose a greater fire hazard than do coarse particles. If possible, remove and disperse elsewhere all bark particles passing a 5-mm screen. If this is not possible, do not allow a concentration of these particle sizes in any given area within the piles. Keep the small particles dispersed among the larger bark particles.
- Construct a temperature monitoring system. Within individual piles, place several Teflon-coated copper constantan thermocouples near the bottom of the storage pile near the geometric center. Attach this thermocouple to a thermocouple receptacle with a battery-operated temperature recorder and take a reading twice a week. The temperature should approach a threshold value. If at any time the the temperature exceeds 95°C, ventilate immediately, which may be done automatically via air duct or by using a front-end loader to remove some of the bark.

- It is recommended that a permanent internal venting system be constructed in the pile. This may be automated by controlling a damper and blower with the thermocouple controller and relay. During winter months, the heat can be transported to nearby buildings for heat. During the summer, it can be vented into the atmosphere.

Covering Storage Piles of Green Wood Fuel

Conceptually, piles under cover would be protected from rainfall. Initially, it seems that green residue would not benefit from cover because of the high initial moisture content. However, the outer shell of storage piles can increase from 44 percent to almost 66 percent in moisture content during a 6-month storage period. Even if spontaneous drying occurs internally, the average moisture content of the pile may increase due to the saturated outer shell. For example, a 6-meter cone with a 45^{o} angle of repose has a volume of 240 m^3. If the outer 0.3 m is universally saturated at 66 percent and the inner zone has an average moisture content of 30 percent, the average moisture content of the pile, weighted by volume, is 40 percent. The <u>smaller</u> the pile, the <u>greater</u> the effect on average moisture content of the outer zone. If this 6-meter pile were covered and the outer shell dried to perhaps 37 percent moisture, then the average moisture content for the pile would approach 33 percent. The value of wood as a fuel affects the accuracy of a break-even or cost/benefit analysis of the covered approach.

Covers can take many forms, from a plastic film to an entire building. Plastic films tend to retard spontaneous drying and contribute to very high temperature increases in the piles. Long-term covered storage of green fiber must be well ventilated. Silos or bins are usually limited in size and are appropriate for small inventories or to maintain surge capacity when uniform metering is necessary. Although bins and silos are not ventilated, ventilation is not necessary for short storage cycles (i.e., less than 1 week).

With green particles, the outfeed of a covered storage system is a critical problem area. Most retrieval systems in silos must feed across the bottom to the center by a drag chain or auger. Such retrieval devices tend to create cavities over the drag chain when large (i.e., greater than pulp chip size), non-uniform particles are encountered.

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Bin storage appears to be appropriate for small inventories of green wood or bark particles of various sizes. The "clam-shell" opening on the base of several commercially available storage bins is well suited to gravity loading of conveyors. The large opening and screw auger greatly reduce bridging problems. However, if the problem occurs, it can easily be remedied.

For large inventories, the cover must be ventilated to allow moisture-laden hot air to escape from within the pile. The cover should be constructed to allow air to enter the base of the pile and pass out of the top. It should resemble a barn used to store hay and allow air to enter the base and hot moisture-laden air to exit the top without permitting rainwater to enter. Fuel can be moved in and out using a front-end loader. The coverings can be translucent for solar energy collection, and the base of the structure can be a black collection surface.

A covered system for green material may be designed to cover all or part of the fuel. Where large inventories are required, a moving cover may be placed over only the active storage sector and then moved to the next zone as this area is depleted.

Heat of Combustion Changes in the Wood Fuel in Storage Piles

The energy contained in wood increases from 5 to 7 percent over a 6-month storage interval near the center of certain large storage piles. The extent to which this occurs throughout the pile is unknown and currently under investigation.

Wood is a chemically heterogeneous material; the heat of combustion of each constituent differs. During storage, chemical alterations probably result in a higher concentration of wood components with higher heats of combustion. For example, certain carbohydrates may be oxidized during storage, leaving a higher concentration of lignous materials known to have a higher heat of combustion.

Although the energy per unit of dry fuel is greater after short-term storage, the total energy in the pile is less at the same moisture content because energy has been liberated as heat. How much less can be determined if the total material converted to heat is known.

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For example, a 6-meter conical pile of 240 m^3 may contain about 120 green tons of 50 percent moisture-laden material. If, throughout the pile, an average of 4 percent of the dry matter was converted to energy and liberated as heat and the energy was 17 GJ/dry ton, then the net energy in the pile at the beginning of storage was 1,101 GJ, and after storage, 979 GJ.

There seems to be a tendency for the unit combustion value to stabilize after 5 or 6 months' storage. Studies indicate that the unit value may actually begin to decline after long periods of storage.

Acidity pH of Stored Green Fuel

Fuel handling equipment, combustors, and boiler hardware are affected by the acidity (pH) of fuels. When burned, moist acidic fuels can corrode combustion chambers, boiler tubes, and ductwork. Chemical activity in large wood or bark piles causes a drop in pH from 5-6 to 3-4 (which is extremely corrosive) during 5 months' storage. The most dramatic increase in acidity occurs within the first 30 days of storage. Bark appears to be the most acidic. Bark-wood combinations, such as in whole tree chips, will be more acidic than sawdust and less acidic than bark piles.

Chemical treatment that buffers this acidic material tends to retard temperature increases and fiber loss, but it also causes emission problems after combustion. Thus, it is best to combust acidic wood or bark fuels at the lowest possible moisture content while limiting the residence time of the most acidic fuels near materials that can be readily corroded.

Storage of Whole-Tree Chips for Fuel

In general, moisture content changes, internal temperatures, heat of combustion, and acidity are greater in bark piles than in sawdust without bark. Depending on hardwood and softwood mix and storage pile configuration, the conditions will vary. Preliminary results of tests conducted on five hardwood whole-tree chip storage piles indicated that moisture content changes, temperature, heat of combustion, and pH range between

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those discussed for bark and wood (sawdust). This is logical, since whole-tree chips typically contain 15 percent bark.

Discussion has centered on the storage of wood fuel as particles. Particles are currently easier to handle in large volumes than is roundwood. However, in-woods chipping costs are high. New procedures for handling and storing large quantities of fuel wood in round form are now under investigation; initial cost analysis of these procedures looks attractive. Current efforts include field drying of stems after felling and the baling of all fuel-type material up to 100 mm in diameter. Baling concentrates the fuel into an easily handled package. A prototype is now being evaluated.

Production rates and the type of binder are critical to the success of this concept. The packages are easily stacked, stored, and transported. Bales could be chipped at the boiler site or, given new designs in combustion systems, could be burned without alteration.

FUEL STORAGE: WOOD PELLETS, SHAVINGS, SAWDUST, AND OTHER DRY RESIDUES

All plants that manufacture wood furniture and other wood products generate residue in the form of blocks, sawdust, and/or sanderdust. These waste materials have frequently presented a disposal problem. Some firms hauled to landfills; other firms chose to incinerate their residues. A few companies burned the waste in boilers to reclaim the heat energy, but they were often faced with problems caused by the seasonal imbalance between supply of residues and demand for energy.

This section discusses the benefits, drawbacks, techniques, and justification of seasonal storage of dry wood residues for use in boilers. Storage of wood pellets will also be discussed briefly.

The main objectives of seasonal storage of wood residues are to:

- Reduce the cost of purchased fuel
- Reduce the cost of waste removal

- Balance the fuel demand and supply ratio
- Maintain the residues in a usable form.

More than one method exists to store residues, but none of them is free. Each method requires space and handling equipment. Before deciding on a storage method, it is necessary to determine how much surplus will be stored. The capital expense of storage must be covered by the savings of purchased fuel. Small volumes of residues can be stored economically, but inexpensive storage and handling techniques must be used.

The form of residue being produced affects storage methods. End trim, blocks and edgings, sawdust, shavings, hogging waste, sanderdust, or combinations of these residues can be stored but present different problems. Blocks cannot be handled with pneumatic or screw systems, and they generally must be hogged (i.e., broken into small particles) before burning. Sanderdust is highly explosive; small particles of sawdust and sanderdust are easily blown away and are more susceptible to picking up moisture if exposed to rain or water seepage than are other residues. Obviously, there is much to be considered before storage is started. Some of the most common storage methods are presented below.

Open Storage Methods

The least expensive way to store residues is on the ground exposed to the elements. Residues stored in this way pick up moisture and dirt from the ground, are wetted by rain, and are subject to wind blowing. This method can be improved by leveling the storage area and covering the ground either with plastic and then a layer of residues or with crushed stone, plastic, and then a poured concrete slab. Preparing the storage area in this manner eliminates ground moisture and dirt and makes the work area more accessible in bad weather. However, dry residues will still get wet with a consequent reduction in their available energy content. Thus, open storage usually is unsatisfactory for storage of dry residues.

When blocks and edgings are stored, they generally must be hogged before burning. If they have been stored without protection, they will hog more slowly than will unweathered material. An additional hog may be required to keep up with fuel demands, and may be necessary whenever stored material is hogged immediately before burning, because in the winter, when the stored material is used, existing hogs will often be at full capacity grinding current production. The easiest and cheapest way to overcome this problem is to hog all residues as they are produced.

Covered Storage Methods

The least expensive way to protect stored residues from the weather is to cover them with plastic or tarpaulins. Rocks, boards, or old tires can be used to hold the covers down. This method offers good protection from rain and moderate winds and can be used for storage of hogged material in many situations. However, strong winds will tear plastic, and more permanent covers must be used.

The next step in sophistication is storage in an open shed. This is basically a pole structure with a roof. It offers fair protection from rain for most of the floor space, but does little to protect the residues from wind or driving rains.

The cheapest materials handling system for the storage methods discussed so far is a bucket- or front-end loader. If a remote storage site is used, a dump truck is needed to haul the residue between the mill and storage area. This equipment is frequently already available at wood products plants.

To accommodate hogged residues with automated handling systems, a closed structure is desirable. A peaked roof structure will make the best use of space, assuming that residues are being dropped to a pile from above. An A-frame sheet metal structure is suitable. A space should be maintained between the pile and the walls to minimize the fire risk. A closed structure with filtered vents permits fines to be blown in without allowing fugitives to escape.

A metal, wood, or concrete structure is relatively expensive. One alternative structure which is less expensive per square foot is a flexible fabric bag inflated by air. The bag, commonly used to cover tennis courts and swimming pools, is sealed around the foundation to make it airtight; access is through an airlock tunnel. The structure is inflated and maintained by either electric or gasoline-powered fans pulling air from the outside and creating a positive pressure of 3/4 bar.

Storage in a silo is another possibility. However, silos are usually not suitable for seasonal storage of wood residues. They are best used for balancing weekly supplies, not for long-term storage. Material stored for long periods in a silo packs down and may bridge when removal is attempted. Furthermore, the cost per cubic meter is relatively expensive. Several silos will be needed to handle the large volumes required for seasonal storage. The cost is further increased because each silo needs its own fuel handling system.

Wood Pellet Storage

Wood pellets are formed by the compression of dry sawdust and bark. The volume required to store an equivalent amount of pellets is about one-sixth that for shavings (see Exhibit 17.2). When the pellets are wetted, they rapidly absorb water, swell, and disintegrate. Thus, pellets must be stored in a dry area (e.g., silo, sealed bunker, closed building). Dust can be a problem with pellets (or with other stored dry wood fuels), and care must be taken to avoid the risk of explosion during storage and handling -- all metal surfaces inside and around the storage area should be grounded, and sparks and naked flames must be avoided.

STORAGE VOLUMES AND COSTS

The volumes required to store various dry fuels are given above. **The bulk density figures are approximations** and should be verified experimentally by any plant considering fuel storage. Cost figures for various storage methods are highly site-dependent. Table 1 gives approximate figures for capital costs. Land, labor, and materials handling costs are not included.

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Exhibit 17.2

Estimated 10-Day Storage Volumes for Various Dry Fuels for Conversion Systems Operating at 77-Percent Efficiency*

Conversion system GJ/hr	**10-day storage volume (m^3) by fuel type**				
	Shavings	**Sawdust**	**Hogged fuel**	**Blocks**	**Pellets**
5	1,000	500	400	300	175
10	2,000	1,000	800	600	350
20	4,000	2,000	1,600	1,200	700

*Assuming a higher heating value of 18,730 kJ/kg, moisture content 10 percent, and densities 96 kg/m^3 (shavings), 176 kg/m^3 (sawdust), 224 kg/m^3 (hogged fuel), 320 kg/m^3 (blocks), and 560 kg/m^3 (pellets).

Table 1. CAPITAL COSTS FOR VARIOUS STORAGE SYSTEMS

Storage method	Cost (dollars/m^2)
Open storage	
On ground	0
On slab	10.80
Covered storage	
Plastic on ground	0.20
Plastic on slab	11.00
Silo (without conveyors)	48.00*
Open shed	60.00
Closed shed	80.00
Air bag	40.00

*Per m^3.

FIELD OBSERVATIONS

Several techniques of storage were observed and monitored in North America during the 1978-79 season. Moisture contents as well as bulk densities of the stored materials were measured at sites representing most of the above-mentioned storage methods. Water reduces the net heating value of wood because some of the wood's heat content is used to evaporate water from the wood.

Unprotected hogged fuel reached a moisture content of 42 percent. A simple plastic cover kept the moisture content below 20 percent. Hogged material in an air bag remained below 15 percent. These differences in moisture content could justify the additional cost of the air bag over plastic when a large volume of fuel is stored. Furthermore, handling plastic over a large area is labor-intensive and can lead to water leakage at joints in the plastic. In cold climates, a pile of wet residues can freeze solid, which may make retrieval impossible.

Some of the major concerns expressed by firms engaged in seasonal storage were as follows: weathered blocks and trimmings presented a problem when being hogged. The hog design and capacity must be considered because of the leathery texture of the material. Those firms having sanderdust were concerned about suspended particles and potential explosions in the stored piles. If the sanderdust can be diverted to the boiler and burned as it is being produced, this problem will be reduced.

HANDLING AND PREPARATION OF WET AND DRY WOOD RESIDUES

No important differences exist between wood fuel handling hardware and the residue handling system generally used in the wood products industry. Generally, wood fuel is most easily handled in hogged form. This section will assume that most fuel will be hogged as soon as possible after production or receipt.

As the price of fossil fuels increases, it becomes advisable for wood products firms to maximize their use of wood fuels. The waste wood produced by a plant often cannot meet the total steam demand, so the possibility of purchasing wood for fuel becomes attractive. This purchased fuel will come in the form of hogged fuel, sawdust, bark, or whole-tree chips. A mobile chipper at the harvest site produces whole-tree chips from forest residues and low-quality timber, which are loaded into trailer vans for transportation to other using facilities. Unloading these vans can present problems at most plants using purchased wood fuel, as well as at some wood products plants.

Unloading

There are many different means of unloading wood fuel, depending on means of transport. Dump trucks and self-unloading vans, which eliminate the need for any plant unloading equipment, may be the most attractive means of transport if a plant requires no more than two or three loads of additional wood fuel per day. Used dump trucks and trailers can often be obtained very cheaply; new trucks may cost as much as $80,000 to $1.2 million.

Since they can carry more fuel, self-unloading vans will be better than dump trucks for transporting larger quantities of waste wood or whole-tree chips. These vans cost between $32,000-60,000 and can usually dump an entire 20- to 25-ton load in less than 10 minutes. These vans are to be compared to the standard whole-tree chipping operations which load semi-trailers pneumatically.

"Chip vans," the semi-trailers used to carry wood, are the most common means of transporting wood fuel in North America. There are several means of unloading them. The most common is the hydraulic truck dump. Dumps can cost from $40,000 to more than $200,000, depending on the design. The more sophisticated and expensive dumps have self-unloading hoppers and can elevate the whole tractor-trailer rig; others elevate only the trailer. These units can cycle a 23-ton load of fuel in about 6 or 20 minutes, respectively.

Another option for unloading chip vans is the Scoop-Roveyor, an extendable boom that mines the wood from a trailer and removes it on a belt conveyor. This device, developed by Morbark Industries, Inc., can unload a trailer in less than 30 minutes. It costs about $100,000.

Other options include systems developed in-house to meet plant applications. Some low-cost options use a small front-end loader or a flexible pneumatic pipe. These systems are slow and labor-intensive, but if requirements are small, they may be the most economical method of unloading wood fuel.

Conveying

Once the fuel is generated or unloaded, it must be moved to storage or the boiler via methods commonly used in the wood products industry. The fuel system frequently is integrated into, or is the same as, the major conveying system in the plant.

The basic type of fuel handling system is a front-end loader. The loader will, in some cases, be the only equipment required for in-plant fuel handling.

Conveyors, the more conventional fuel handling equipment, come in four general classes: pneumatic, screw, belt, and drag/flight chain. Each type has its advantages and disadvantages.

<u>Pneumatic conveyors,</u> which are most frequently used in the furniture industry, work well on clean, small particle fuel such as finely hogged dry waste, sawdust, and

sanderdust. As the particles become heavier and larger, energy requirements increase significantly, and equipment wear becomes a major problem.

Screw conveyors are the most expensive of the three mechanical conveyors (screw, belt, and chain). The screw conveyors also have problems with large or stringy wood fuels such as bark. They do offer two very distinct advantages. A screw conveyor can convey up steeper inclines than can a belt or simple drag chain which can be important in certain situations where space is a problem. Also, because a screw can meter fuel, it is attractive for boiler feed applications.

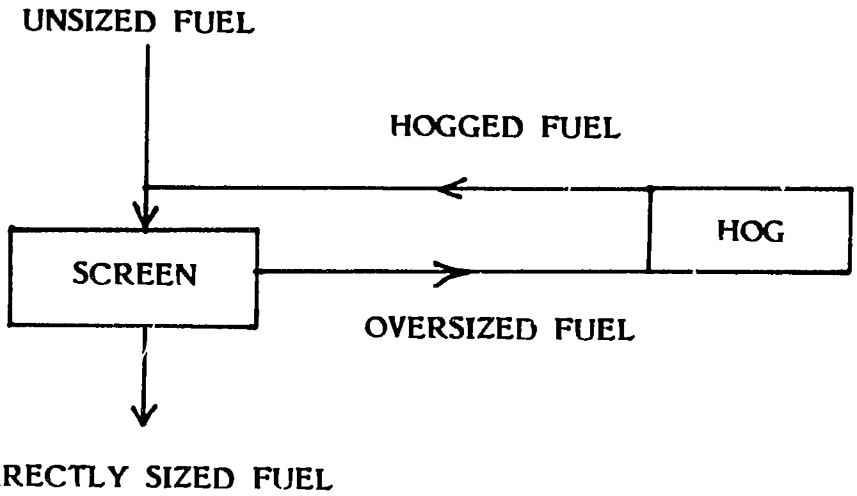
Rubberized belt conveyors are the least expensive mechanical conveyors and also have the lowest energy requirements. They can convey any type of wood fuel, though light, dry particles can be blown off by the wind. Although they are versatile, belt conveyors are restricted to no more than a 15° incline. This limitation makes them unattractive if the fuel must be elevated over a short distance.

Drag/flight chain conveyors fall somewhere between the screw and the belt in initial cost. They are rugged, versatile conveying systems with low energy requirements. Depending on the design of the flights (or paddles), chains can be used to undermine fuel piles, convey up steep inclines, or even feed the stokers in the boiler.

The selection of the conveying system depends on the plant layout, fuel type, and system cost. No one type is best for every application, though as mentioned, some lend themselves to a particular situation.

Sizing of Fuel Particles

Uniformly sized fuel particles facilitate both handling and combustion. A system involving a screen and a hog is commonly used to provide this uniformity (see schematic below). Energy use and maintenance costs are reduced by screening out correctly sized fuel and hogging only the oversized fuel.



Two types of screens are generally used in this application. The shaker screen is a mesh within an inclined, vibrating frame. The correctly sized particles fall through, and the oversized particles are shaken off the top. The disk screen is made up of overlapping rotating disks that allow correctly sized particles to fall between the disks; the oversized particles are carried out of the screen by the rotating action. The maintenance and operation requirements of the disk screen are less because it is self-cleaning.

The term "hog" is used to refer to a device that reduces the size of particles. Two types exist: the knife type, which chips the wood, and the hammermill, which beats and grinds the particles against a screen. As mentioned earlier, it is desirable to minimize the amount of fuel that passes through a hog. A hog, at idle, requires very little energy and experiences very little wear, and by placing it in a bypass loop, it is used only as needed.

Drying

The issue of drying fuel before burning is in dispute. There is no question that the drier fuel burns better and has a higher heating value per pound. On the other hand, large amounts of heat are required to drive off the moisture in wood. The heat requirement is approximately 3,970 kJ/kg of water removed when conventional rotary drum dryers are used. Approximately 2,790 kJ/kg at 200°C is required to evaporate the water when the drying is accomplished as part of combustion in a boiler.

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Two methods of drying are used: the rotary drum dryer and the suspension dryer. Both operate on the same principle -- the use of hot air traveling through the dryer and being brought into contact with the particles. The source of hot air can be a gas burner, a wood suspension burner, or, in some cases, boiler flue gases. Drying equipment is expensive to install and operate, especially if costly fossil fuels are used.

The idea of using boiler flue gases is attractive since there is no fuel cost. Only limited success has been achieved, and many systems have been outright failures. The three factors that cause the most problems are the high moisture content of the gases, low temperature (i.e., 200°C versus 500°C for most dryer applications), and the corrosive nature of cooled flue gases. Additionally, energy must be supplied to a fan to move the hot gas across the resistance of the dryer and to prevent backpressure in the boiler furnace.

Although each element of the handling system has been discussed separately, they must be integrated into a smooth flowing system. The flow to and from storage, the flow of residues from the production facility to the fuel handling system, and the reliable flow of fuel to the boiler must be taken into account.

The system must be able to handle surges. If a short-term failure of some element in the handling system occurs, an alternative means of supplying the boiler needs to be considered. Both of the above needs can be met with one or more surge bins. These are small storage devices immediately following a fuel input or before the boiler feed. They act as a buffer in the system.

Fuel handling must be viewed as a system. The goal of the system is to fuel the boiler. If a part of the system fails, contingency arrangements should be prepared to continue supply. A well-designed and integrated system will fulfill this requirement.

POWER FROM WASTE

By Robert G Schwieger, *Associate Editor*

Combustion of industrial wastes and municipal refuse in waterwall steam generators offers an opportunity to conserve valuable fossil fuels, while at the same time eliminating a potential source of environmental pollution. Industry has been burning many of its wastes for years, but today this practice is becoming widespread as experience reveals its tangible benefits. The technology for large scale recovery of energy from refuse, although relatively new in this country, already is being applied commercially. This report should serve as a guide for engineers investigating the methods for burning wastes and refuse as fuels in new and existing boilers in industrial plants and electric utilities, as well as those responsible for plant design and operation

Experience in burning waste abounds throughout industry

Methods used by petroleum, paper and sugar plants provide guidance for your waste-to-energy projects

The concept of disposing of industrial waste products by burning them as fuels—in gaseous, liquid, or solid form—is not new. Yet it is only in the past several years that this practice has become widespread. The recent interest in burning wastes generally can be attributed to one or more of the following factors:

- Cost of waste fuels is lower than that of fossil fuels.
- Waste disposal by more conventional methods—for example, landfill of solids or venting of gases—is being restricted.
- Incinerators without heat-recovery capability usually are costly to build and operate, in view of today's stringent requirements for air-pollution control. Reason: They produce large amounts of hot flue gas which must be cleaned up.
- Process wastes generally are very low in sulfur content. Thus, they can be burned along with the more readily available high-sulfur fossil fuels, to bring within permissible limits the concentration of sulfur compounds in the flue gas.

To illustrate how wastes can be made to work for you, let's take a look at the state-of-the-art in waste-fuel utilization in some major industries. Although this discussion is only representative of what is being done today, realize that the technology and equipment used by one segment of industry to solve its problems often can be adapted to other situations—perhaps yours.

In general, solid wastes are burned on a fuel bed or in suspension; liquids, in atomized form. Except in rare cases, these do not differ appreciably from the handling of coal or oil. Gaseous byproduct fuels, however, are more apt to require special treatment.

Before reaching a final decision as to how a particular waste should be handled and burned at your plant, consult the boiler manufacturer. He has experience with a wide variety of byproduct fuels, and generally can guide your

Typical industrial wastes with significant fuel value

Waste	Average heating value (as fired), Btu/lb
Gases	
Coke-oven	19,700
Blast-furnace	1139
Carbon monoxide	575
Refinery	21,800
Liquids:	
Industrial sludge	3700-4200
Black liquor	4400
Sulfite liquor	4200
Dirty solvents	10,000-16,000
Spent lubricants	10,000-14,000
Paints and resins	6000-10,000
Oily waste and residue	18,000
Solids:	
Bagasse	3600-6500
Bark	4500-5200
General wood wastes	4500-6500
Sawdust and shavings	4500-7500
Coffee grounds	4900-6500
Nut hulls	7700
Rice hulls	5200-6500
Corn cobs	8000-8300

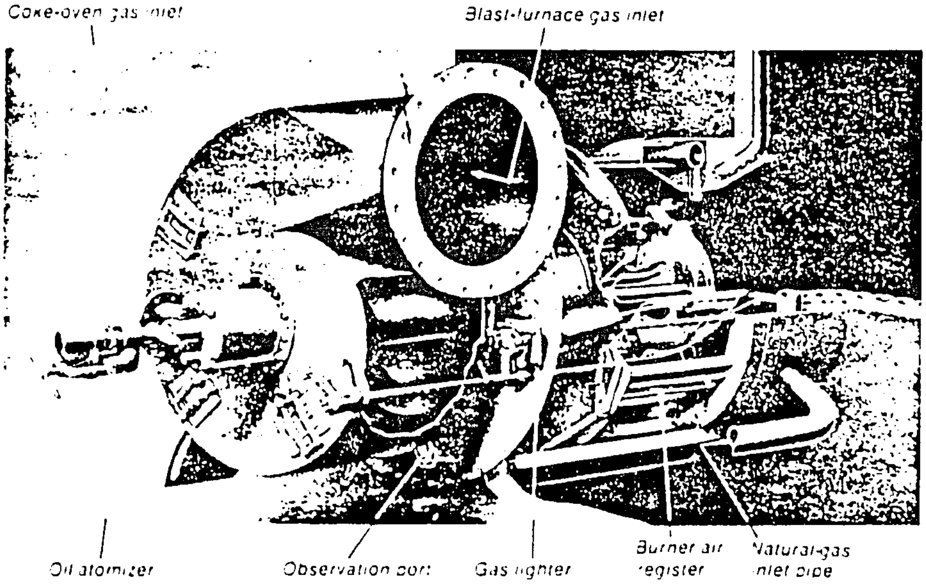


Fig 1

Combustion equipment is available to burn virtually all process waste gases and liquids. Scroll burner (left), for example, is designed for low-heating-value gases. Liquid wastes often are incinerated in a refractory-lined furnace (below)

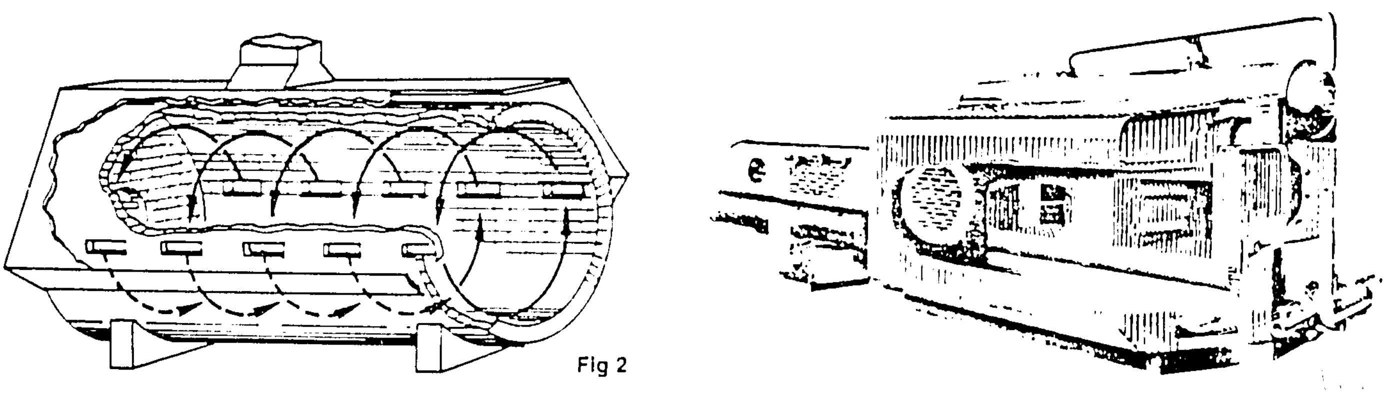


Fig 2

project with a minimum of engineering time. Make his job easier by properly identifying waste type, quantity and characteristics. Physical and chemical properties that should be provided, if available, include: (1) heating value, (2) ignition temperatures, (3) percentages of volatile matter, fixed carbon, hydrogen, ash and moisture, (4) density, (5) ash-fusion temperature, (6) corrosion potential of fuel and combustion gases, (7) toxicity and odor of gases, (8) explosion potential, (9) variability in quantity and quality, (10) special handling problems, and (11) viscosity characteristics (for liquids).

Gases. Refinery and coke-oven gases make excellent fuels. Proper combustion of these fuel gases, as well as most others with heating values greater than 500 Btu/cu ft, requires only minor changes in the design of conventional natural-gas burners.

Refinery gas is produced when crude oil is processed into gasoline and other products. Its composition depends on the type of oil being refined and on the refining process itself; thus, it varies widely. Heating value is higher than that for natural gas because refinery gas contains a higher percentage of heavier hydrocarbons. Before being burned in a conventional boiler, it usually is mixed or blended with gases from other plant operations to produce a fuel with a heating value of about 1500 Btu/cu ft.

Coke-oven gas, which ranges in heat content from 460 Btu/cu ft to 650 Btu/cu ft, is produced during the high-temperature carbonization of bituminous coal to make coke. Fuel quality depends on the type of coal processed, the duration of the coking operation and the temperature of the coke oven. Coke-oven gas usually is cleaned and cooled to ambient temperature prior to combustion. But since it may still contain a small amount of particulate matter, a nozzle having a large free area is employed, rather than gas spuds. The fuel nozzle is installed in the center of the burner; combustion air is admitted through the air register surrounding it.

Usually, the small amount of solids present do not demand that restrictions be placed on flue-gas velocities. Thus, in most cases, coke-oven gas can be burned easily, even in a package boiler, once burner modifications are made.

Regenerator gas produced by refinery fluid-catalytic-cracking units is typical of most waste gases in that it has a high inert-gas content and is relatively high in solids. Note that the degree to which the inerts are present, and the quantity, size and character of the solids, strongly influence boiler design. Regenerator gas has a relatively low combustible content (about 40 Btu/cu ft from carbon monoxide in quantities less than 10% by volume), but since this waste product is available to the boiler at temperatures ranging from 700 F to 1000 F, its sensible-heat content is high. To use the heat efficiently, a trap, such as an economizer, is specified for the boiler.

The low heating value of the gas makes it necessary to burn a minimum amount of supplemental fuel at all times. Combustion of carbon monoxide occurs at about 1300 F, and supplemental fuel keeps the furnace temperature several hundred degrees above this value for proper incineration.

Carbon-monoxide boilers are designed for continuous base-load operation with a fixed quantity of waste gas and a minimum amount of supplementary fuel. While these units have the capability to increase load by using additional supplementary fuel, they cannot operate below the minimum steaming value fixed by the waste-gas volume and the corresponding supplementary-fuel requirement. Boiler designs vary from special field-erected units to packaged steam generators.

In a typical D-type packaged boiler, regenerator gas is admitted into the furnace through side-wall or front-wall ports; the necessary combustion air is added through the auxiliary burner.

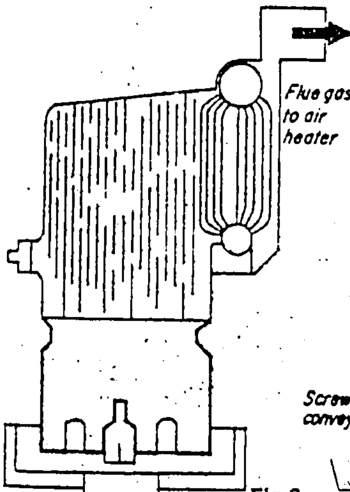


Fig 3

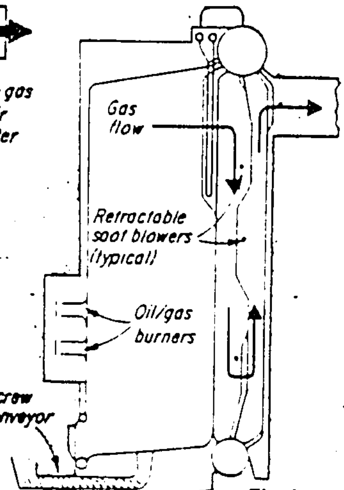


Fig 4

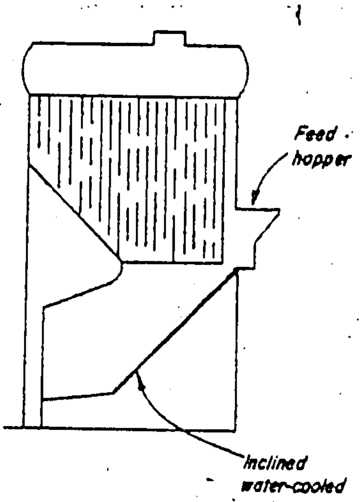


Fig 5

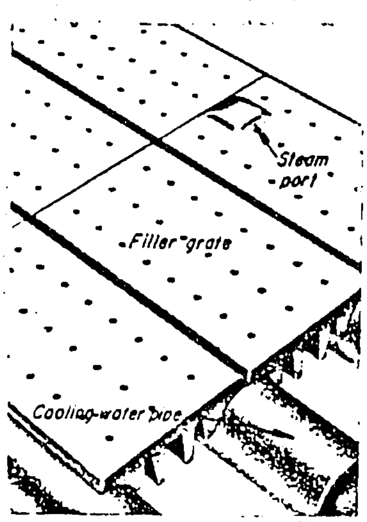


Fig 6

Boilers designed to handle industrial solid wastes often use mass-burning principles—especially in small sizes. High-moisture fuels, like coffee grounds, sometimes are burned in a cell-type furnace, either on flat grates or on the furnace floor (Fig 3). Low-ash, easily burned wastes, such as those from a sawmill, can be conveyed to the boiler and consumed on the floor (Fig 4), or they can be dropped from a hopper onto an inclined grate (Fig 5). Ash usually is blown off the grate, which may be water-cooled, by steam (Fig 6). Bulky industrial wastes generally are burned on a reciprocating grate (Fig 7).

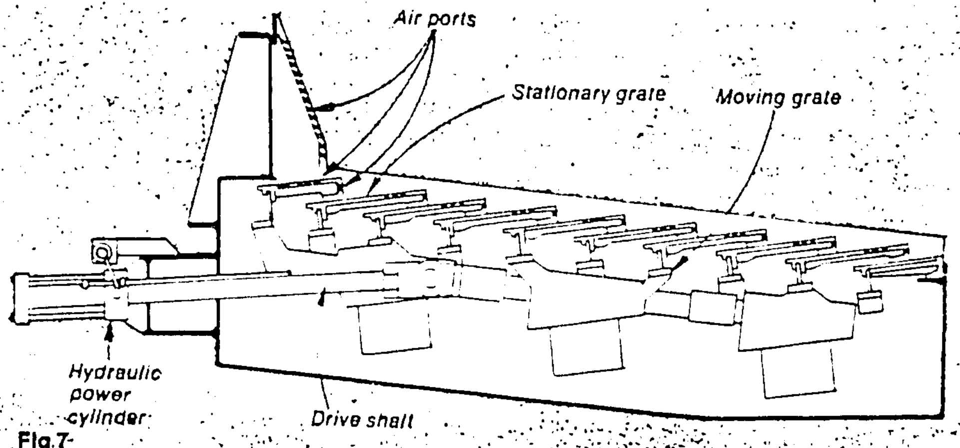


Fig 7

Higher efficiencies generally result from burning solid

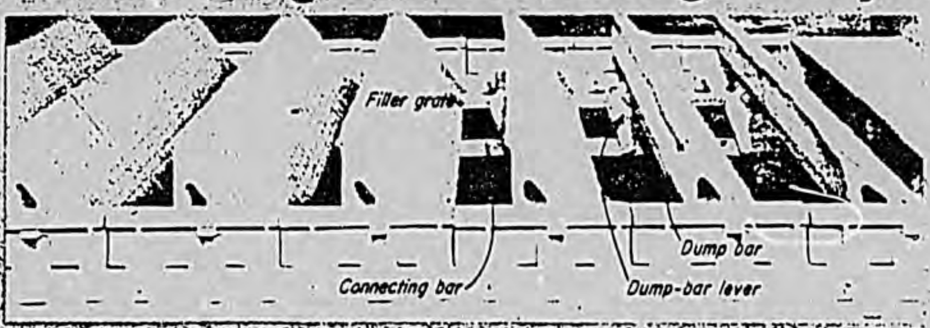


Fig 8

In most industrial boilers, solid wastes are fed into the furnace by pneumatic or mechanical distributors. Some or all of this material is burned in suspension. When the unit is not designed for complete suspension burning, final burnout usually takes place on a grate. The stationary grate, with or without water cooling, offers the simplest design (Fig 6). Dump grates are used on occasion in small units for high-moisture fuels (Fig 8). In larger boil-

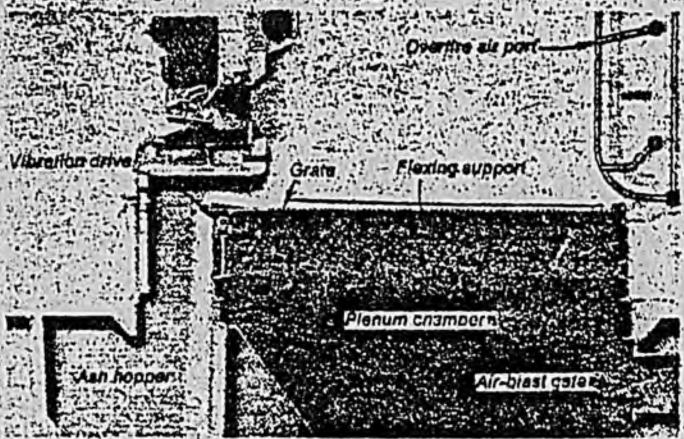


Fig 9

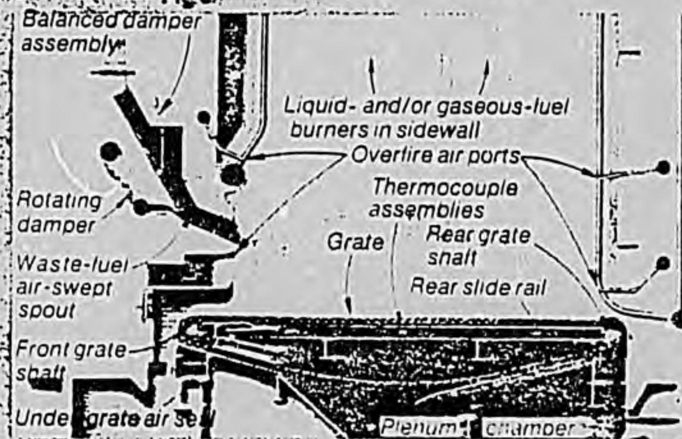


Fig 10

Boiler-bank free area is sized to provide gas velocities of less than 100 fps, to minimize tube erosion from solids.

Blast-furnace gas, a dust-laden byproduct of the iron-reduction process, derives its value as a waste fuel from its high carbon monoxide content (as much as 30% by volume). Gas can be burned as discharged from the blast furnace, but it generally is cleaned prior to use because the high dust loading (5 grains/scf to 7 grains/scf) would cause plugging of burners and fouling of heat-transfer surfaces.

Boilers designed for steel-industry service must be capable of responding to rapid changes in load and fuel availability. To maintain desired steam production under all process conditions, burners are designed to handle supplemental fuels as well as waste (Fig 1).

Designing a boiler to burn one or more waste gases in conjunction with conventional fossil fuels offers a tremendous challenge to the engineer. To illustrate: For a given rate of steam production, the quantity of combustion products passing through the boiler varies considerably as the rate of burning each fuel changes. Hence, steam-temperature control in units with high-temperature superheaters becomes a difficult task. Design conditions are complicated further by the variations in heating value with time, for some waste fuels such as blast-furnace gas.

Liquid industrial wastes vary considerably in viscosity, moisture, heating value, and flash and fire points. Some that can be used as fuels include solvents, waste oils, oil sludges, oil/water emulsions, polymers, resins, chlorinated hydrocarbons, phenols, cresols, tars, combustible chemicals, greases and fats.

When relatively homogeneous byproducts are available in quantity—such as some liquid residues from refining processes—conventional burners and boilers often can be modified with little difficulty to burn them.

If large quantities of blended wastes are a problem, one method of handling them is to incinerate the entire waste stream in a refractory furnace, and then recover heat from the combustion gases in a conventional boiler (Fig 2).

The cylindrical Loddby furnace illustrated is designed to burn from 50-million Btu/hr to over 200-million Btu/hr of high-moisture liquid wastes. A supplementary fuel may be required if the heat content of the waste is too low. In operation, wastes are sprayed into the combustion chamber through a burner nozzle, and air is admitted tangentially along the length of the furnace, creating a cyclone effect. The differential pressure between the wall and the center of the furnace causes a portion of the hot gases to recirculate back to the burner area. This way, liquid wastes are dried before reaching the wall area.

Note that the combustion of liquid byproducts from pulp mills is not discussed here because the systems and equipment for preparing and burning them are designed primarily to reclaim process chemicals.

Solid wastes. The cane-sugar, paper, furniture and plywood industries have had vast experience in extracting energy from solid process wastes. Bagasse, the portion of sugar cane that remains after sugar is extracted, consists of matted cellulose fibers and fine particles. The percentage of each constituent varies with the process. Cane waste normally is high in moisture—from 40% to 60% by weight—and often has a high ash content, resulting from silt picked up during the harvest.

Bark and wood waste, unlike bagasse, vary substantially in fuel characteristics with geographic location and mill practices. Species, type of soil, mode of transportation and method of debarking also influence fuel quality. For example, the approximate moisture content of bark resulting from hydraulic debarking ranges from 60% to 75%; from drum debarking with wet handling, 45% to 65%; from drum debarking with dry handling, 35% to 50%.

The composition of wood waste used for steam generation falls into three broad categories:

- Sawmill wastes, consisting of sawdust, shavings, bark, etc in varying percentages.
- Prepared wood sold as a boiler fuel, consisting primarily of chips, with little or no sawdust or shavings.
- Paper-mill wastes, consisting mainly of bark.

process wastes in suspension

ors, ash is removed from the grate continuously; either vibrating (Fig 9) or traveling (Fig 10) grates are suited for this type of service. Where wastes have good combustion characteristics, and/or when a highly turbulent gas stream exists in the furnace, a large portion of the waste material is consumed in suspension. Under these conditions, final burnout may take place either on the furnace floor (Fig 11) or on a small burnout grate (Fig.12)

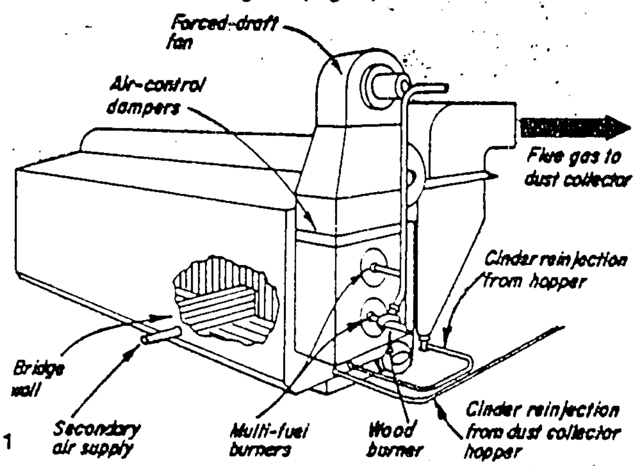


Fig 11

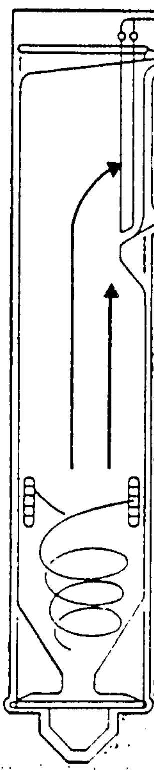


Fig 12

Bagasse, wood, and other solid process wastes can be burned in a boiler furnace (1) in mass, (2) in suspension, and (3) partially in suspension, with final burnout on a thin bed. Final choice depends heavily on the size of the installation and the steam-generating efficiency desired.

The simplest method of mass burning is to take unprepared waste and burn it on a pile in a refractory cell-type furnace fitted with either stationary or dump grates. Years ago, this was a standard method of destroying bagasse but, since combustion is relatively inefficient it is seldom used today. One of the few remaining applications for this type of furnace is for coffee grounds, which have a high moisture content (Fig 3).

Grounds are the residue remaining after instant coffee is made. They are flushed from the process to a blow-off tank, and then pass through a rotary press, which produces a cake containing 60% water. The cake is pumped into each of the boiler's four refractory cells through 3-in.-diameter cast-iron thimbles set in the roof of each compartment. Hot combustion air is supplied through side walls of each cell.

The cells are designed so that a sloping roof projects out past the side walls of the boiler. Refractory, therefore, almost completely surrounds the pile of coffee being burned, insuring ignition and good burnout of the grounds, with a minimum of auxiliary fuel. At full boiler load—100,000 lb/hr of 200-psig saturated steam—about 55% of the heat comes from coffee waste, and the remainder from two oil burners mounted in the front wall. Warmup gas burners also are provided for each of the refractory cells.

Some low-ash wastes, such as sawdust, can be mass-burned in small boilers with acceptable efficiency by gravity-feeding them from a hopper to an inclined stationary grate (Fig 5). What little ash there is eventually works its way to the bottom of the incline, where it can be removed manually or blown off the grate by steam (Fig 6).

Another way to extract heat from sawdust and wood shavings is to feed the wastes into a modern water-cooled furnace and burn them on a stationary floor grate (Fig 4). As shown, the wood byproducts are deposited in the boiler by a variable-speed, under-floor screw conveyor. This insures quiet delivery, minimizes particulate carryover, provides good coverage of the grate and, at the same time, allows the wood to dry slowly as it is fed up from the bottom of the pile. For part-load operation and more-efficient pile burning, the grate is divided into two sections. The center, where the pile is, receives high-pressure air; the periphery, low-pressure air.

The tall furnace in this unit represents a relatively new concept in packaged-boiler design. It was developed originally to optimize shop assembly of fossil-fired steam generators, larger than 200,000 lb/hr, without compromising good boiler design and efficiency. But the so-called tower boiler appears to be ideal for burning waste fuels—such as hogged wood, sander dust and bagasse—in mass, or partially in suspension with final burnout on a grate.

Furnace height provides maximum time for combustion and assures low furnace exit temperatures, while longitudinal gas flow through the generating bank reduces gas-side pluggage and erosion problems with minimum draft loss. The unit shown, capable of producing 60,000 lb/hr of steam at 425 psig, 500 F when burning hog fuel alone or No. 6 oil alone, has three burners in the front wall. Retractable sootblowers are provided in the boiler bank.

An efficient way to mass-burn many solid wastes, especially those that vary in size and composition, is on a reciprocating grate (Fig 7). Modular construction permits these grates to be arranged in any combination of widths and lengths to fit rectangular furnaces of almost any size, and to supply whatever grate area is necessary to handle wastes in quantities above about 1000 lb/hr.

Reciprocating grates are adaptable to intermittent batch feeding either by charging ram or bulldozer; however, continuous charging is recommended for higher efficiency when the unit is large enough to justify a crane. Grates are arranged in lateral rows, each overlapping the adjacent row in shingle-like fashion. Alternate rows are linked to a power source which slowly reciprocates them back and fourth across the faces of the stationary rows. Movement of the grate tumbles the waste, thus aerating it and providing maximum surface exposure to the flame. Combustion air is supplied through closely and evenly spaced ports in the grate castings. Noncombustibles and ash can be discharged intermittently, by use of a dumping grate, or continuously.

Thin beds. Perhaps the most popular method for generating steam from solid wastes is to burn some of the combustible material in suspension and the remainder on a thin bed. This approach requires that the waste material be prepared before admitting it to the furnace. For relatively homogeneous waste streams, all that's generally involved is size reduction. In sugar mills, for example, a shredder with revolving knives cuts the cane waste, which then passes through sets of grooved rolls, each set comprising a mill having finer grooves than the preceding one. The end product has a high percentage of fines and short fibers.

The paper industry, similarly, uses hoggers or chippers to reduce the size of its wood and bark wastes.

Once the byproduct fuel is sized for proper combustion, it is transferred, by

Metering devices regulate the flow of waste to the furnace

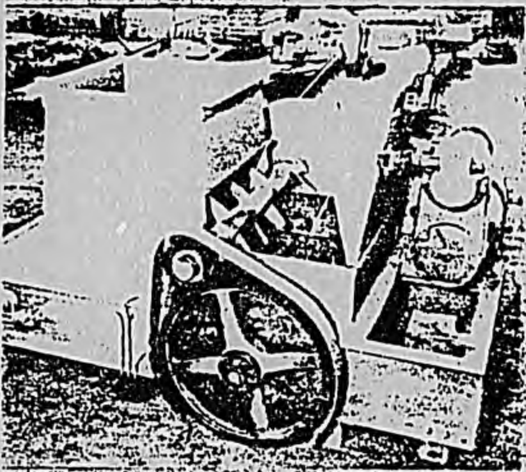


Fig 13

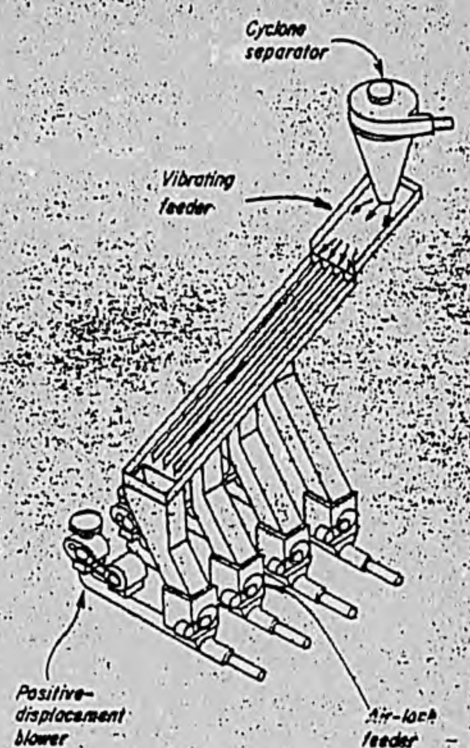


Fig 14

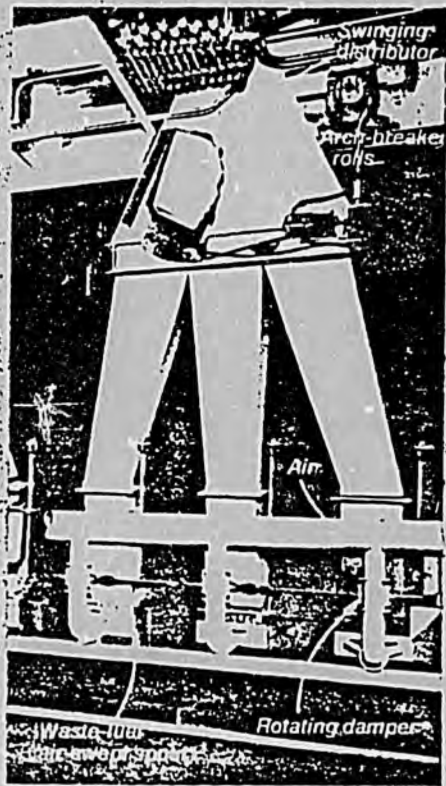


Fig 15

Bagasse and similar materials are fed to furnace distributors by metering conveyors like that shown in Fig 13. Feed rolls rotate counterclockwise to break up masses of stringy waste in hopper. **Vibrating feeders** (Fig 14) are more apt to be used for wood wastes. Swinging spout (Fig 15) is another device for distributing waste fuels to furnace feed chutes. Arch-breaker rolls prevent hangups

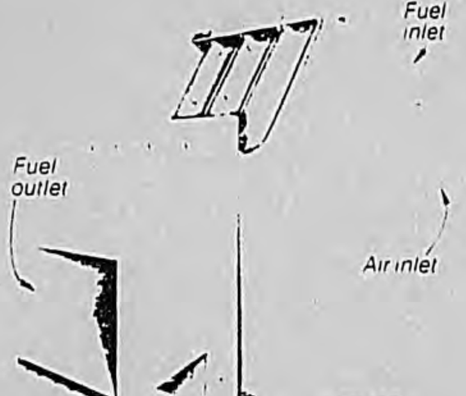


Fig 16

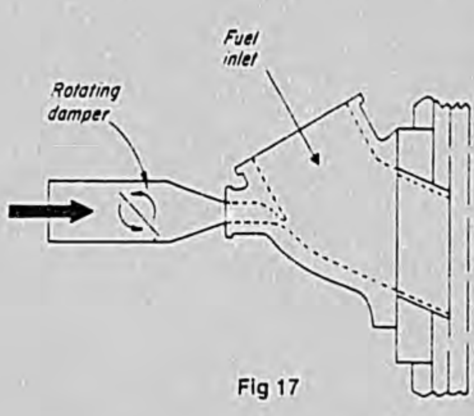


Fig 17

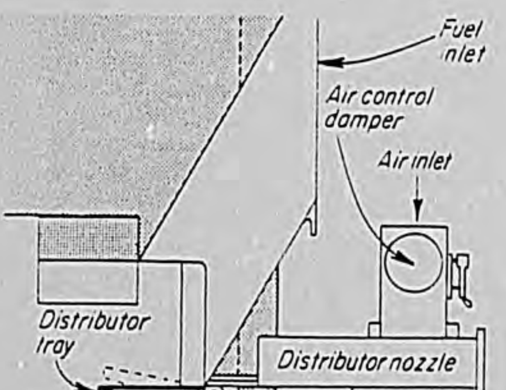


Fig 18

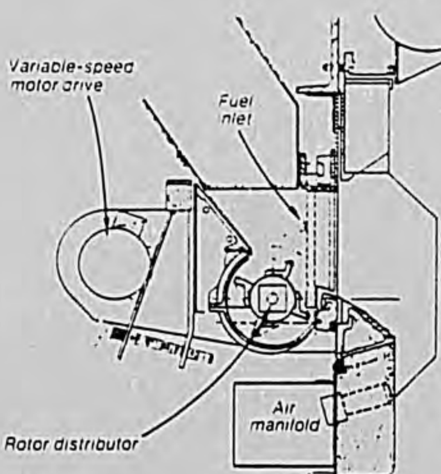


Fig 19

Pneumatic feeders come in many designs (Figs 16-18) and sizes to match fuel and furnace requirements. One unit has a motorized damper which continuously varies air pressure and quantity to assure even fuel distribution from front to rear of furnace. Mechanical feeder is used with stringy waste fuels (Fig 19). Overthrow rotor has specially designed blades to promote good distribution throughout the furnace

a metering device, to a pneumatic or mechanical feeder for distribution in the furnace. A typical metering conveyor for bagasse and similar stringy materials is shown in Fig 13. Vibrating conveyors (Fig 14) can be used for a variety of wastes such as wood chips, plastics, etc. They distribute fuel equally to each of the supply lines provided. A positive-displacement blower and air-lock feeder, in turn, transport fuel to the firing assembly. The use of a pneumatic system enables waste preparation, storage and metering to be located away from the boiler house.

The swinging spout is another device for distributing fuel equally to furnace injection points (Fig 15). Its operation is simple: Waste material supplied to the spout by a conveyor is distributed in nearly equal quantities to each chute as the nozzle swings back and forth.

Pneumatic feeders are very popular for distributing all types of waste fuels in the furnace. Fuel enters the boiler furnace in a thin, uniform, widely dispersed stream. Much is burned in suspension but, just as important, the remainder is dried, facilitating burnout on the grate provided.

Grate arrangements include the stationary (Fig 6), dump (Fig 8), vibrating (Fig 9) and traveling (Fig 10) types. Horizontally oriented stationary grates are used in small boilers only occasionally, and then just for easily burned, low-ash wastes such as sawdust. Dump grates also serve infrequently. One

Flash drying systems, sand classifiers handle special jobs

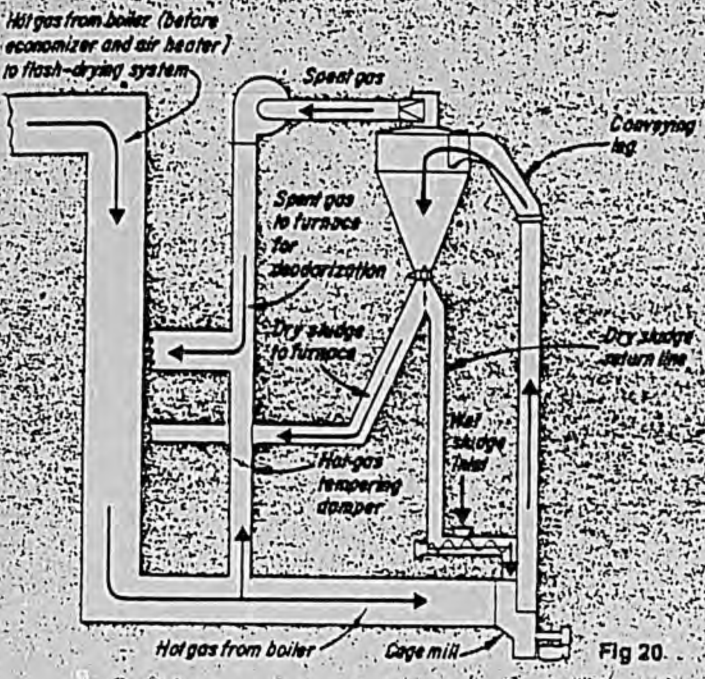


Fig 20

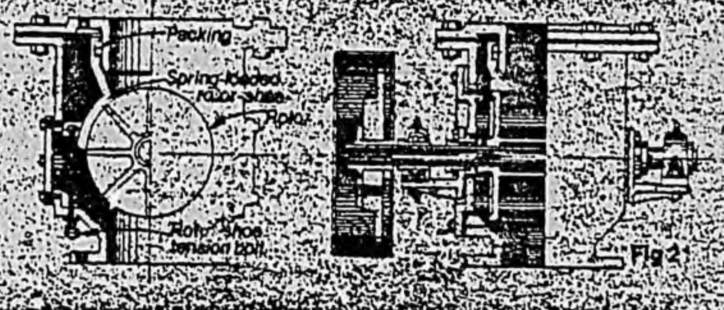


Fig 21

Fig 22

Flash drying system permits high-moisture sludges to be burned in an industrial boiler of proper design (Fig 20). Rotary-seal feeders at boiler hopper outlets remove flyash under high differential pressures (Fig 21). Classifier is used on some bark-burning units to separate sand and fly carbon collected in back-pass hoppers, so sand is not reinjected along with the carbon (Fig 22)

problem with them is that, when they are dumped, particulate emissions may increase beyond that allowed by air-pollution codes. This condition can be corrected by installing more efficient cleanup equipment, but the cost usually cannot be justified for the small installations that normally use dump grates.

Stationary and dump grates have been replaced in many plants by continuous-cleaning fuel beds. In one design, the grate surface is vibrated intermittently, as a unit, by an electrically operated eccentric-drive assembly mounted at the front end of the boiler. A timer automatically controls frequency and duration of vibration cycles in response to boiler load. Note in Fig 9 that the spreader stoker feeding the vibrating grate is designed for coal firing. This would, of course, be replaced with a distributor designed for the particular waste fuel being burned.

Traveling grates are the most popular type for solid-waste-fired boilers larger than about 50,000 lb/hr. The endless grates move—at speeds between 4 and 20 ft/hr, depending on steam demand—toward the front end of the boiler, discharging ash continuously. Preheated cooling and combustion air are supplied through air slots and pin holes in the grate; air temperature depends on the moisture content of the fuel, but rarely exceeds 500 F.

Increase efficiency. With spreader-stoker installations, it is good practice to collect unburned combustibles from back-pass and dust-collector hoppers, and to reinject them into the furnace with the overfire air. Reason: Efficiency can be improved about 2%. Some of the equipment used for this purpose is shown in Figs 21 and 22.

When low-ash waste products can be chopped or ground to small sizes, they usually can be burned almost entirely in suspension. Consider, for example, the modified D-type package boiler for the furnace industry that is illustrated in Fig 11. The unit has two burners. The lower one has a pulverized-coal-type nozzle for burning the wood waste; the upper burner is for oil or gas.

Shavings and sawdust are introduced into the system at the inlet of the primary-air fan, which conveys the wood particles to the lower burner, along with about 20% of the theoretical combustion air required. A forced-draft fan supplies the remainder, plus air for the supplementary fuel. The small percentage of wood that does not burn in suspension falls to the furnace floor ahead of a bridgewall. There it burns, aided by a small amount of air introduced through the bridgewall. Every six months or so, the furnace is raked out and cleaned of all noncombustibles.

The only restrictions on boiler design imposed by wood-waste combustion are limitations on gas velocity and volumetric heat release. Experience with these packaged units dictates that, with about 1% ash and a small quantity of sand in the wood, gas velocities in the fuel nozzle and boiler should be maintained below 70 fps to prevent excessive nozzle and tube wear. Heat release is kept below 60,000 Btu/cu ft for normal operation, with 85% of the total heat input coming from wood. Approximately 15% of the total heat must be supplied by the supplemental fuel to insure burnout of the larger wood shavings on the floor.

Suspension firing of solid wastes is more prevalent in large paper mills, where field-erected boilers are designed specifically for burning wood wastes. In one design (Fig 12), bark is introduced at points high in the furnace by tangential firing assemblies. The wood is flash-dried as it enters the furnace, and most of it is burned in suspension. A small dump grate provides for burnout of oversize particles.

Industrial sludge. One of the more difficult classes of waste fuels to incinerate is sludge. Despite the high percentage of moisture contained in these wastes, however, they can be burned in a boiler if they are properly prepared. One way to do this is to use a flash-drying system (Fig 20).

In operation, the wet sludge is received, blended with a portion of dried sludge, and fed to the cage mill, where flash-drying is initiated. Hot flue gas from the boiler completes the drying process in the vertical conveying leg. A cyclone separates the spent dry gases from the dry sludge, and most of the sludge is conveyed to the boiler.

6-46

How to condition refuse for suspension firing in boilers

Municipal refuse is converted into a fuel for power plants by shredding and removing noncombustible matter

Spiraling energy and raw-materials costs, and restrictions on landfill activities, have transformed municipal refuse from "garbage" to a valuable resource, which contains a substantial number of recycleable materials and a substantial amount of energy. Whether some or all of the materials found in refuse can be recovered economically depends on their value and on the cost of recovery, both of which vary widely from location to location. One thing is sure, however: Energy recovery *is* economically attractive—now.

There are several ways to extract energy from municipal refuse (diagram, below). Two of these recovery techniques use the contents of the entire garbage pail and, generally, do not provide for materials recovery. The easiest approach is to landfill refuse in conventional fashion and draw off the gas produced by the decomposition of organic material. Although this fuel gas contains about 500 Btu/cu ft and is of a quality that can be burned in a boiler, a gas turbine or an internal-combustion engine, recovery is not efficient, and the problems associated with sanitary landfills still exist.

A better way to release energy from raw refuse: Burn it on a grate in a stoker-fired industrial boiler or waterwall incinerator to produce steam for process heating or cooling or for generating electricity. Note that the terms "boiler" and "waterwall incinerator" are two different ways of saying "refuse-fired waterwall steam generator." The first is more commonly used by domestic boiler manufacturers when referring to their equipment; the latter by foreign incinerator manufacturers.

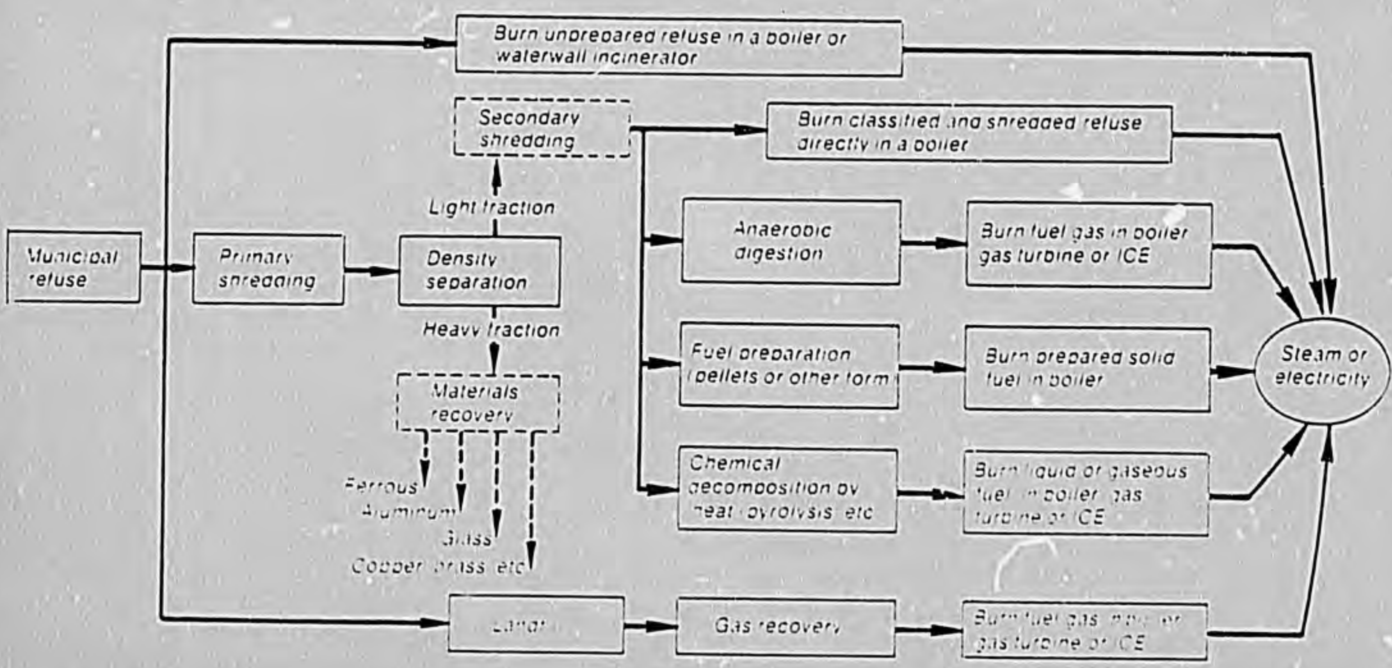
Several other methods recover energy from the waste stream after noncombustible materials have been removed. The most direct, and perhaps the most practical, is to burn the prepared, organic portion of the refuse in a standard utility or industrial boiler, in conjunction with fossil fuels. Other ways—such as anaerobic digestion and pyrolysis—generally convert the organic fraction into a more conventional fuel, which can then be burned in a boiler, gas turbine or internal-combustion engine. The extra step associated with these methods could, however, increase the cost of recovered energy.

Selection of the energy-recovery system best suited for your area will be based, in part, on commercial experience, economic considerations and local variables. If the first two points are high on your list, then systems designed to burn raw or prepared refuse in a waterwall steam generator will be prime candidates. Reasons: Plants of these types have had a great deal of operating experience, both here and in Europe; the other systems have not. Furthermore, costs associated with boiler and incinerator projects can be estimated realistically; the other methods are in various stages of development, and costs are not well defined.

Assuming that you have narrowed your selection down to the mass-burning and suspension-firing systems cited above as prime candidates, the next step is to determine what is involved in preparing refuse for suspension burning. The various resource-recovery processes also must be investigated. With this information, you can evaluate the advantages and disadvantages of stoker and suspension firing more accurately.

The waste stream

Government statistics show that the average citizen produces over 5 lb/day of waste products, with an average heating value of between 5000 and 6000 Btu/lb. Nationally, Americans throw away, each year, over 125-million tons of refuse from residential and commercial sources. This contains more than 1.2-million billion Btu, 30-million tons of paper, 4-million tons of plastics, 48-billion cans and 26-billion bottles and jars. These numbers are increasing annually. About 75% of this waste is found



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Conveyors and bucket elevators handle refuse fuel and ash

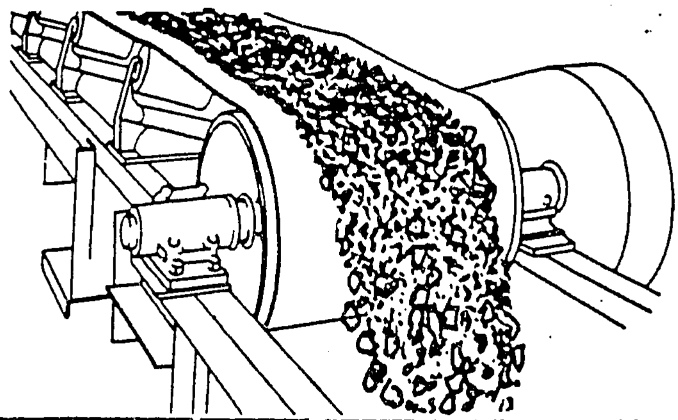


Fig 24

Fig 25

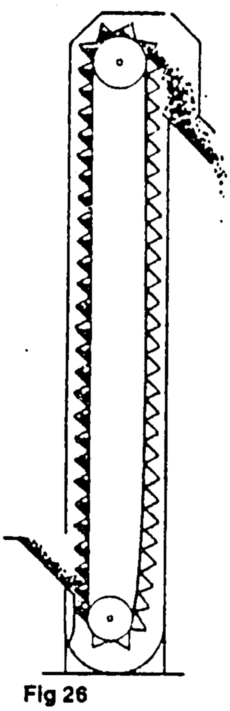


Fig 26

Fig 27

Belt conveyors, which offer relative simplicity, few moving parts and low power requirements, can do many of the materials-handling jobs in refuse-fired power plants (Fig 24). To illustrate: In some facilities, fixed-end-discharge conveyors are used to control the flow of raw refuse to shredders, carry the shredded refuse to resource-recovery systems and storage bins, convey reclaimed materials to loading docks, and move bottom ash out of the plant. Where raw refuse must be lifted at steeper angles, such as from live-bottom storage pits, apron conveyors may be the choice (Fig 27). When the pit is full, the cables shown support some refuse to prevent overloading of the conveyor motor. Drag conveyors are popular for removing bottom ash and flyash from quenching troughs in systems that burn unprepared refuse (Fig 25). Finally, remember that bucket elevators sometimes are specified for vertical lifts in ash-handling and resource-recovery systems. Continuous type has greatest capacity (Fig 26).

in major metropolitan areas, where energy- and materials-recovery plants would be economically feasible.

In many respects, refuse is not an ideal fuel. The myriad of municipal and commercial wastes do not lend themselves to accurate definition by particle size, moisture, chemical composition or general physical characteristics. Wide fluctuations in these variables, which are influenced by weather, economic conditions and changing technology, occur on a daily and seasonal basis.

The physical composition of refuse is outlined in the table on p 73; chemical properties on p 83.

But raw refuse can be transformed, by dry (as-received) or wet shredding, into a relatively homogeneous mixture, with uniform size, heating value and moisture content. Almost all refuse to be shredded is milled as-received.

A wide variety of equipment is available for reducing the size of raw refuse, but hammermills are the most popular. Two basic mills used for this service are the swing-hammer type and the fixed- or rigid-hammer type. Swing- and fixed-hammer machines are similar, except that in the former the hammers are pivoted on the rotor (Fig 31) to prevent internal jamming and damage. To reduce the need for presorting, hammermills often are equipped with an ejection mechanism to remove nongrindable material. Mills vary in power requirements, depending on the type and quantity of material to be processed. Medium-duty mills used in shredding municipal refuse typically require 25 hp per ton-hr of throughput.

Hammermills may have a gravity-feed or a forced-feed system. The compression or force feeder (Fig 32) can eliminate some input problems, jam-ups and choking by pushing material into the shredder at a continuous rate, and by flattening bulky items.

Most machines have hammer shafts oriented in the horizontal plane; some, however, have vertical shafts. In the vertical unit illustrated (Fig 36), milling begins in the prebreaking section. In the rejection section, which is the narrowest part of the machine, heavy or resilient objects that are not reducible are hit by the hammers and thrown up the sides of the cone—like a ball in a spinning roulette wheel. Shredding is completed in the grinding section, and the milled refuse is discharged.

Some crushers perform essentially the same jobs as hammermills. To illustrate: Refuse discharged from the force feeder on one machine is gripped by a slowly rotating shaft holding many gear-shaped plates (Fig 33). A parallel shaft, which rotates faster than the first, has impactors that comb through adjacent gear plates. Both the impactor and the gear teeth penetrate the refuse; gear surfaces act as anvils for secondary penetration. The close clearance between the impactors and the shaft holding the gear-like plates provides further tearing action.

Up to this point, hammermills and

Physical composition of typical municipal refuse

	Weight percent (as fired)	
Category	With yard waste	Without yard waste
Paper	44.2	50.7
Food waste	16.6	19.1
Yard waste	12.6	—
Metal	8.7	10.0
Glass	8.5	9.7
Wood	2.5	2.9
Textiles	2.3	2.6
Leather, rubber and plastics	2.9	3.3
Miscellaneous	1.7	1.7

Feeders usually are of the belt, vibrating or screw types

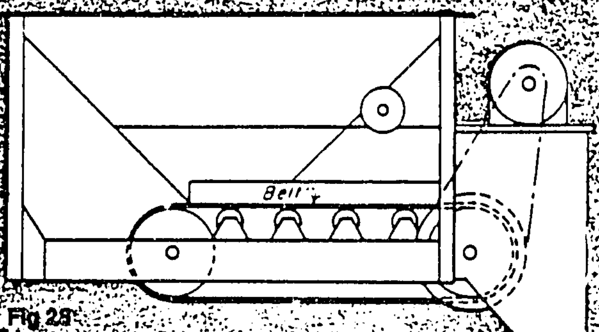


Fig 28

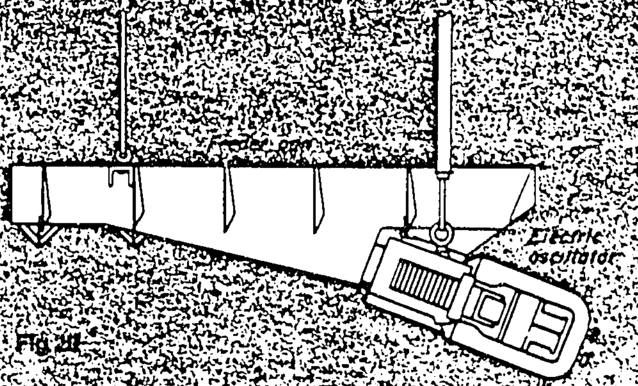


Fig 29

Simplicity, smooth operation and uniform discharge make belt conveyors attractive as feeders. When so used, they are short, and have closely spaced idlers for extra support (Fig 28). Vibrating feeders use an electromagnet, or a rotary drive, to impart vibratory motion (Fig 29). An advantage of these units is that few, if any, parts are subject to friction wear. Hence, maintenance is light. Screw feeders generally are found in storage bins, where they are used to load belt conveyors (Fig 30)

Fig 30

crushers have been discussed with the intent of using them in continuous shredding operations to produce a homogeneous fuel. This use only applies to plants burning refuse in suspension. Facilities that burn raw refuse on a grate often have mills to shred oversize wastes for more convenient handling. Others may use other types of crushing device, such as that shown in Fig 37.

Cost of homogenizing the waste stream by shredding is not low. Power costs are significant, and maintenance can run 60¢/ton of waste milled. Bulk of the maintenance effort is spent to retip hammers and replace grate bars. Hence, it is in your best interest to consider a machine that (1) provides quick access to internal parts, and (2) has easily removable hammers and grate bars. Some units have an added advantage: A reversible rotor, which permits hammers to take twice as much wear before retipping is necessary.

Other aspects that should be considered before making a final selection:

- Protecting plant personnel from explosions or fires that can occur inside the mill during operation.
- Mounting the shredder in a manner to minimize severe vibration.
- Providing protection against excessive noise.
- Designing the materials-handling equipment on the inlet and outlet sides of the shredder in such a way as to minimize the possibility of overload.

Density separation is next

Once municipal refuse is shredded to a top size of 1½ in. or so, it undergoes a density-separation step to remove most of the heavy or noncombustible material. The effects of this step are:

- To increase the heating value of the refuse fuel.
- To minimize wear of pneumatic transport equipment and boiler heat-transfer surfaces.
- To increase the suitability for reuse of bottom ash from the boiler.

Density separation can be accomplished when refuse is dry or in slurry form. But, as mentioned in the section on shredders, virtually all waste is handled dry; thus, discussion here will be confined to such systems.

Air classifiers are used in many industries to separate mixtures of dry materials according to one or more physical properties—such as size, shape or specific gravity—of the particles in the mixture. In food processing, for example, air classifiers separate peanuts and other nut meats from their hulls.

Prior to selecting an air classifier, establish the primary objective of your plant's refuse-processing system. If it is energy recovery, then the classifier you choose should be designed to maximize the amount of clean, light fraction produced. Where materials recovery is the goal, the heavy fraction is of primary concern, and the recovery of metals and glass must be maximized.

The classification system illustrated in Fig 38 appears to be the unit most talked about in utility circles. Its successful operation depends on taking the erratic, variable discharge of refuse from the shredder and metering it, at a constant volume, to the air classifier. This is accomplished by a 60-deg flight conveyor, which permits gravity to level the refuse as it is dragged up to the vibrating feeder. As a backup, a rotating leveling roll scalps off any excess material reaching the top of the conveyor. Refuse then is transported by the vibrating feeder to the infeed airlock, which allows air to enter the classifier only through the falling curtain of refuse in the separation zone.

Hinged panels in the separation area permit you to vary the shape and cross-sectional area of the zone. Thus, with a constant volumetric input of air and garbage, you can control which items drop and which items fly.

Another relatively common type of air classifier has a zig-zag path for the light and heavy streams to follow, rather than the vertical column characteristic of the unit in Fig 38. Design philosophy is that each change in direction, or zig-zag, creates a turbulence in the air stream, which causes the solid waste to tumble and allows bunched materials to be broken up.

The heavy fraction removed from the air classifier is transported to landfill or a resource-recovery system, the light fraction may be conveyed to another shredder for milling to not more than 1 in. in size before it is sent to an appropriate storage bin.

Live-bottom storage bins specified for most, if not all, refuse-to-energy plants committed thus far are shown in Figs 41 and 42. The circular bin, used extensively in the pulp-and-paper and cane-sugar industries for storing chips and bagasse, is very popular. Shredded refuse is conveyed pneumatically or mechanically to the top of this bin and falls onto a conical pile.

Material recovery is accomplished by chains of sweep buckets. From three to six sweep chains are used, depending on

Shredders mill all the refuse, or just large objects

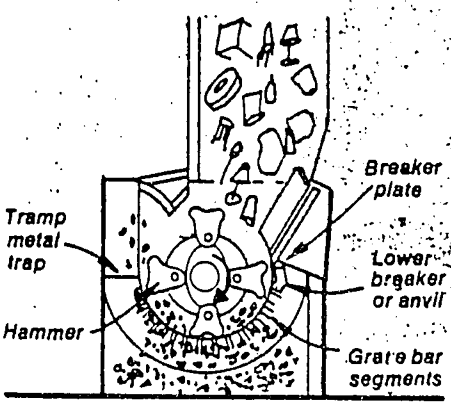


Fig 31

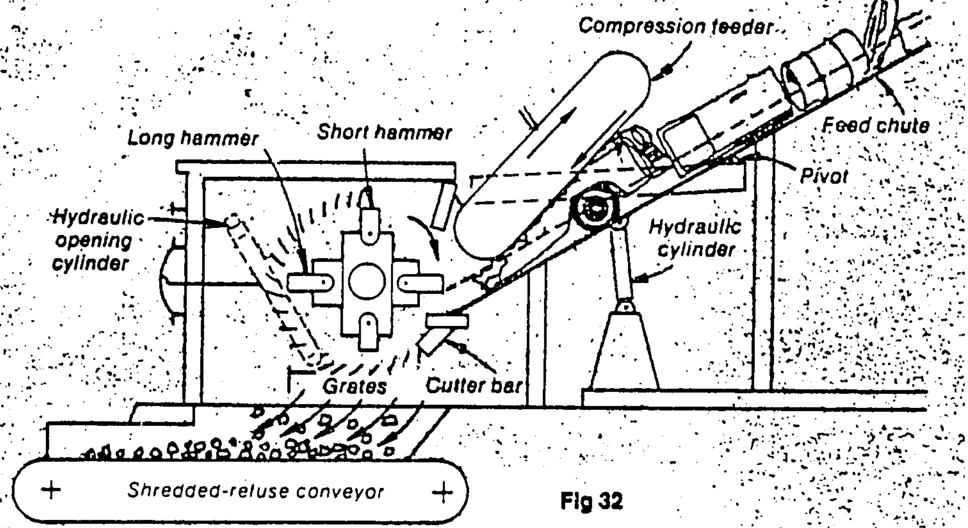


Fig 32

Hammermills with horizontal rotors commonly are used for shredding refuse. These machines are of the gravity-feed (Fig 31) or forced-feed (Fig 32) types. Here's how they work: Refuse fed into the mill is chopped between hammers and breaker plate, then it is ground between the hammers and the grate at the bottom of the unit. Tramp metal is removed by a trap. Design of the hammers or crushing device depends on the vendor. Hammers shown in Fig 34, which weigh about 150 lb each, are typical of those used in a heavy-duty mill. In another design, refuse is broken and torn between adjacent gear-like wheels and impactors which comb through each other (Fig 33)

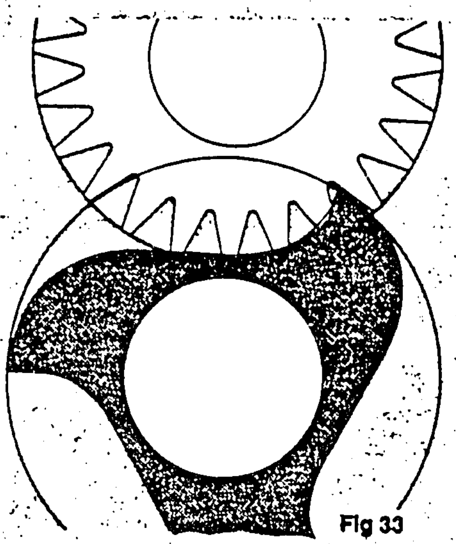


Fig 33

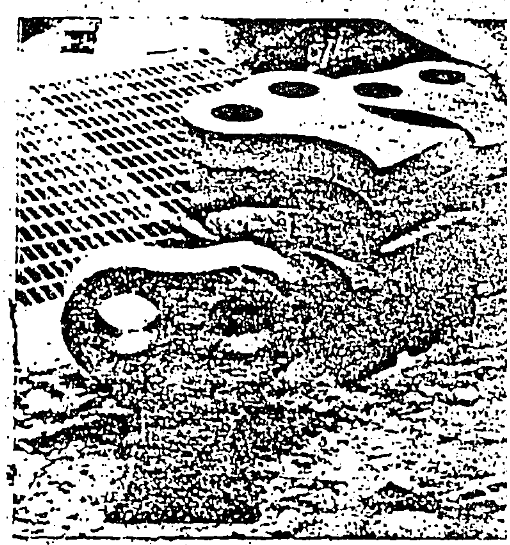


Fig 34

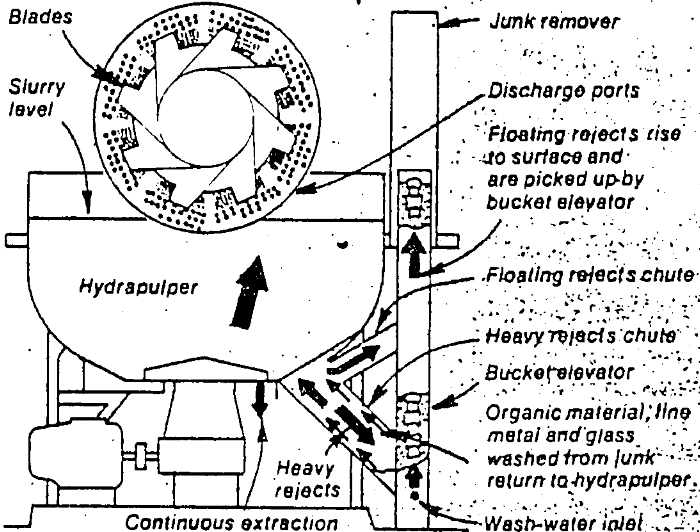


Fig 35

Vertical-shaft hammermills, crushers and Hydrapulpers also are used to reduce the size of raw refuse. The first two handle waste dry; the last, wet. The crusher (Fig 37) is designed to reduce the size of bulky items, such as refrigerators, by crushing and shearing them between its jaws. Hydrapulpers (Fig 35) essentially are oversize blenders, containing water, which convert solid waste to a slurry

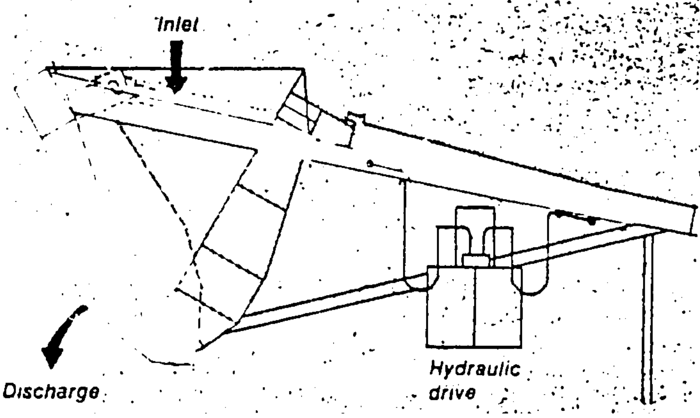


Fig 37

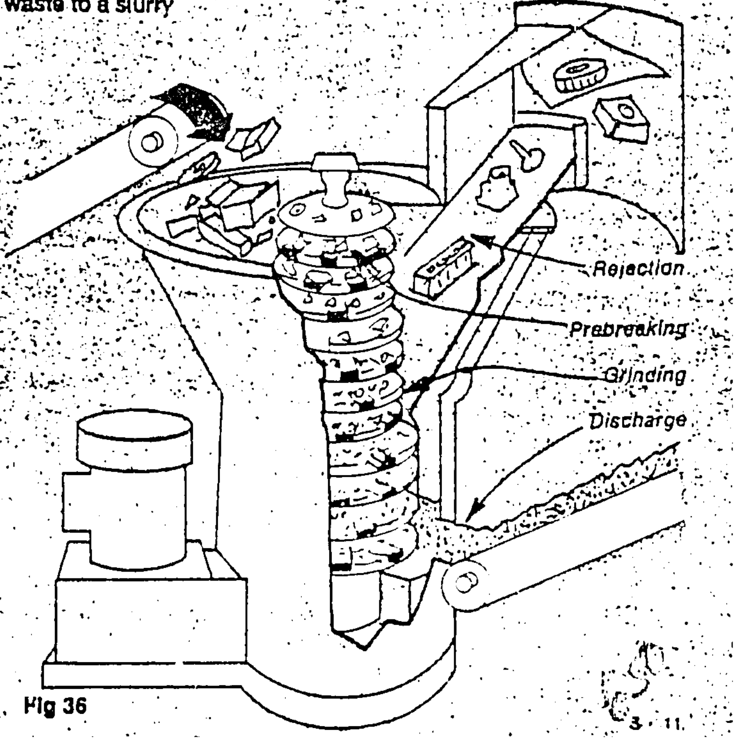


Fig 36

Separating heavy materials from light

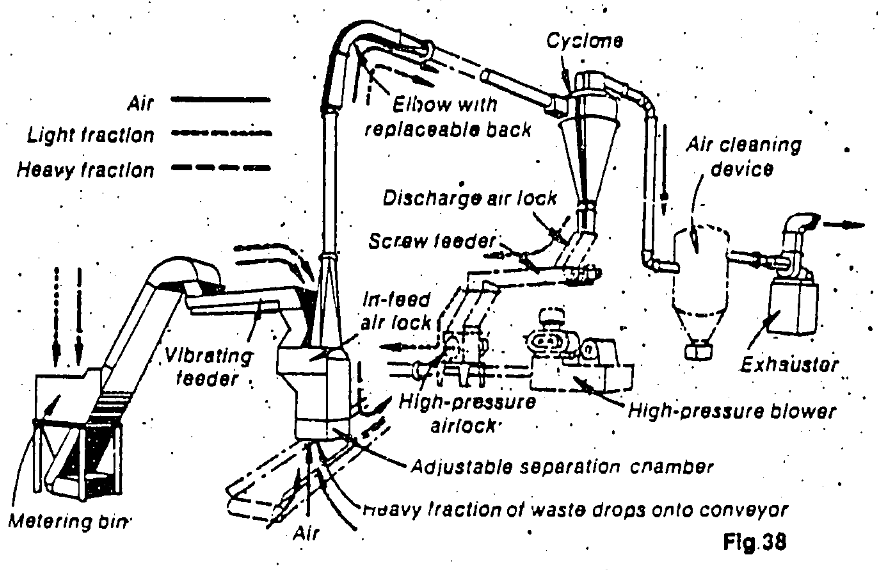


Fig 38

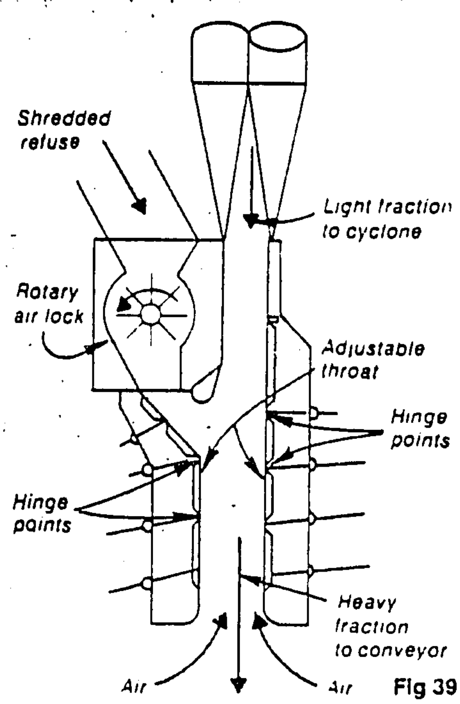


Fig 39

Air classification systems separate the shredded raw-waste stream into two fractions: heavy and light. One system (Fig 38) uses a metering-bin/conveyor unit to deposit refuse on a vibrating feeder, which evens material and screens out much glass, sand and dirt. The rotary airlock (Fig 39) supplies refuse to an adjustable separation chamber. Latter helps control air velocity so the light fraction is lifted up the pipe and the dense fraction is dropped out. Heavy materials are removed by a belt conveyor, while the light fraction is separated from the conveying air in a cyclone. An exhauster discharges transport air to atmosphere; the combustible material is transported to storage. Note that an air-cleaning device can be installed if necessary

bin diameter and the volume rate of flow desired. Each is fixed at one end to the rotating pull ring encircling the storage area; the other end is free.

As the pull ring rotates around the periphery of the bin, the sweep chains automatically trail toward the center. Buckets contact the stored material at the outside of the pile, and, as the pull ring continues to rotate, the buckets fill, and the refuse is swept through the grizzly openings onto an outfeed conveyor recessed in the floor. The conveyor delivers the recovered refuse fuel at a uniform and controlled rate to either a pneumatic or a mechanical conveying system, for transport to the boilers.

Resource recovery

When one hears some of the fabulous prices quoted for scrap steel, aluminum, glass, and copper and brass, there is a temptation to look at the heavy fraction discharged from the air-classification system and think it contains a fortune in readily recoverable materials. Before making any quick decisions, however, consider these facts:

- Most systems for recovering materials other than ferrous metals have not yet been proved commercially.
- Scrap prices are subject to rapid and wide fluctuations.
- Scrap prices often quoted are those paid for materials delivered to the recycling plant; therefore, recovery plants located at a considerable distance from recyclers might find it only marginally economical to ship some reclaimed metals and/or glass.
- EPA is supporting legislation—such as a bill to prohibit nonreturnable bottles in interstate commerce—that ultimately could remove 30% of the steel and 50% of the glass and aluminum from the waste stream.

What this means, in short, is that relatively little is known about the recovery, for profit, of glass and metals from municipal refuse. It should not be considered unwise to invest some capital in materials-recovery systems—but if you do, base your plant economics on the recovery of energy alone or on the recovery of ferrous metals and energy.

Scrap steel cans—the major component of the ferrous metals recovered from municipal refuse—probably can be recycled by four or more industries. The steel industry, for example, has made some promising efforts toward can recycling in the last few years. But old cans generally are not a very desirable raw material because they contain tin, aluminum and lead—all of which can lower the quality of a steel product even if they are present in the melt in relatively small quantities.

Quality of steel scrap can be upgraded to desirable No. 1 dealer bundles if the reclaimed cans are first processed through a detinning plant. Some utilities contemplating large materials-recovery operations have found detinners willing to pay as much as 50% of No. 1 dealer-bundle prices for ferrous scrap delivered to their plants. Remember that the only domestic source of tin is from detinning plants.

Reclaimed steel cans also can be used by the copper-mining industry as precipitation iron to recover copper from low-grade ore, and by ferroalloy producers in the production of melts for foundry castings.

The most common method of recovering ferrous scrap from municipal refuse is to use belt- or drum-type magnetic recovery systems (Figs 43-46). Single-stage systems—that is, those using one magnet—often are found in refuse-to-energy plants that recover scrap after combustion. Multistage systems are needed where steel is to be reclaimed from unburned shredded refuse, because they minimize the amount of foreign material that is carried along with the scrap.

In a typical multistage belt system (Fig 46), three separate magnets are used to do the following: attract metal, convey it a long distance around curve, agitate it, release it, attract the same metal again, redirect its path, convey it again, and discharge it. When attracted metal reaches the area where there is no magnetism, it falls away freely, and any nonferrous material trapped by the metal against the belt also falls. Thus, clean metal is pulled back to the belt by the final magnet.

Aluminum might be removed from the heavy fraction of municipal refuse by either chemical/mechanical or elec-

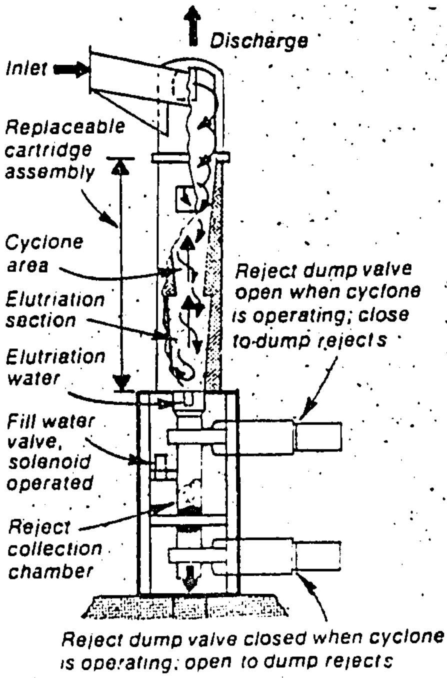


Fig 40

Liquid cyclones are used to separate the light and heavy refuse fractions in wet processing systems. These units have no working parts; they come with ceramic liners in areas of heavy wear to minimize maintenance and equipment downtime

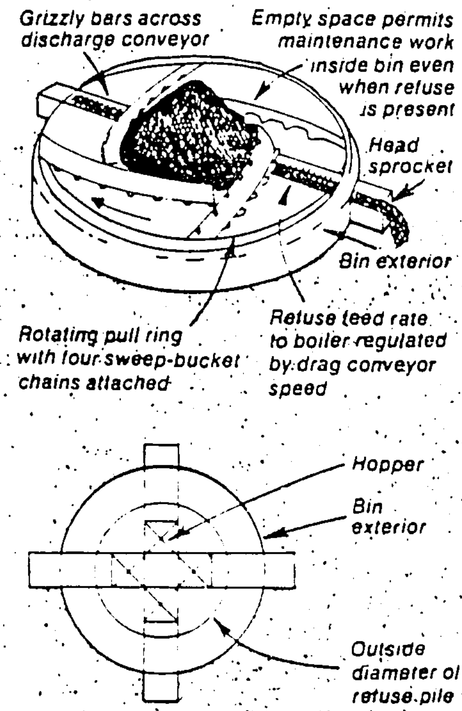


Fig 41

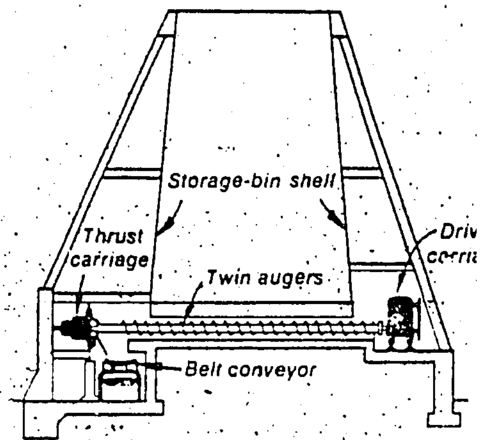


Fig 42

Refuse-to-energy plants that burn shredded waste use live-bottom storage bins to hold the prepared fuel prior to combustion. In one design (Fig. 41), sweep-bucket chains transfer refuse from a central pile to two (top) or four (bottom) conveyors. Another system (Fig 42) has two augers that traverse the bin and deposit the waste fuel on a conveyor

trical separation methods. A system of the first type, called heavy-media separation, has the most operating experience. Even so, there are fewer than a dozen such plants in existence—all in the automobile-recovery industry.

Here is how heavy-media separation works: A shredded feedstock rich in aluminum—such as the noncombustible portion of municipal refuse after ferrous metals and glass have been removed—is dumped into a process stream of high specific gravity. The gravity is maintained at a level that permits the aluminum to float and the other materials to remain submerged. A disadvantage of this approach is that an optimum-size plant requires 2000 to 3000 tpd of feedstock. Thus, it probably would not be economical for use in systems processing less than about 15,000 tpd of raw refuse.

A new type of magnet appears to offer great promise for removing aluminum from relatively small quantities (250 tpd and up) of municipal refuse. There are a few prototype systems operating, and at least one commercial-size system will go into use at a municipal power plant some time this year.

Design of these systems is based on fundamental electrical principles. To illustrate: When a moving magnetic field passes through a nonmagnetic metallic conductor, the field induces eddy currents in the metal. This phenomenon is used to drive a rotary induction motor. If a linear induction motor stator—which can be considered a rotary-induction-motor stator that has been cut and straightened—is placed below a nonmagnetic moving belt, it can create the field necessary to drive nonmagnetic conductors from the belt.

In one system, linear induction stators are arranged perpendicular to the length of a 0.040-in.-thick austenitic stainless-steel conveyor belt, and are positioned underneath the top surface. Nonmagnetic conductors, except stainless steel, are forced upward from the belt and off the side. Early tests of this process indicate that overall recovery of can stock and other aluminum is greater than 75%.

Recovering glass

Clean, color-sorted glass is an attractive raw material to the glass industry, and demand reportedly exists at prices comparable to those of virgin materials. No major process changes are required to use even very large quantities of color-sorted waste glass (known as cullet) in glass manufacturing. There is no proven process for color-sorting of waste glass, however, although at least one method is in the early stages of demonstration. This is a device that is able to sense and reject material having light-transmission qualities different from that of standard glass.

Glass in mixed colors can be separated from other materials in the waste stream by at least two methods—electrostatics and froth flotation. But the economic attractiveness of mixed-glass recovery is not clear. Reason: Use of mixed glass probably will be confined to low-grade products, such as construction and road-paving materials.

High-voltage electrostatic fields can be used to separate glass from the heavy fraction of air-classified refuse, free of ferrous and aluminum scrap, in the following manner: A vibrating feeder meters feedstock to a negatively charged rotating drum, and a positive electrode near the drum and the feeder induces a charge in the small particles. Nonconductors, such as glass and clay, retain the charge; metals and crystalline materials—such as rock—lose it rapidly. The drum holds the nonconductors, and the remaining material drops off.

Froth flotation can be used to recover a container-grade glass cullet from a glass-rich feedstock produced by screening the heavy fraction of air-classified refuse. First step in the process is to immerse the feed material in water, so that the organics and other materials that float can be removed. The glass chips, rocks, bricks, bones and dense plastic that sink are ground in a rod mill, screened to remove rubber and metal chips, and sized for flotation with a screen and classifier.

Material in the minus-20-to-plus-200 mesh size range is dewatered to remove contaminants from grinding, repulped with reagents to a 30%-solids content, and fed to roughing flotation cells, where most of the glass is removed with

Magnets remove ferrous scrap before or after combustion

Fig 43

Iron and steel scrap is easily removed from municipal refuse with either a drum-type or a belt-type magnetic separation system. Single-stage systems (Figs 43, 45) have one magnet and generally are used to pick metal from bottom ash in plants burning unprepared refuse. When refuse is shredded, ferrous scrap is removed before combustion. A multistage system is used here, so the scrap is picked up clean (Figs 44, 46)

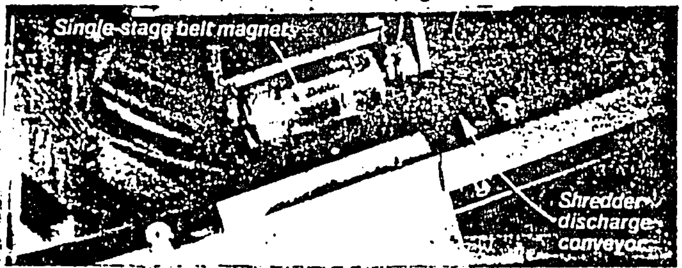


Fig 45

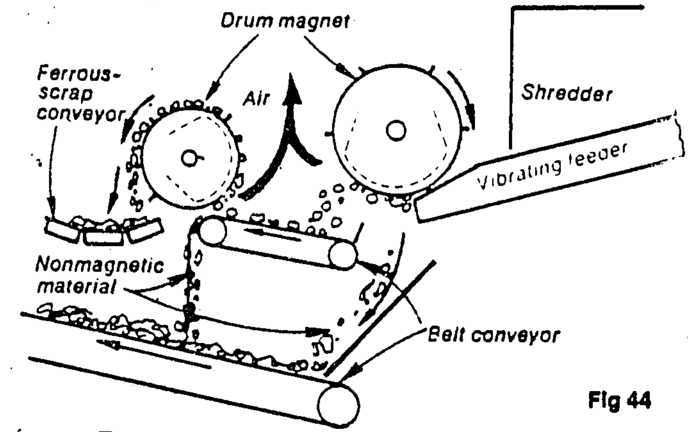


Fig 44

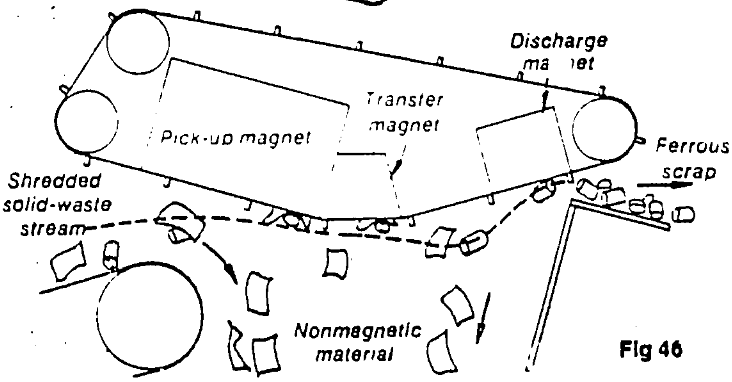


Fig 46

the froth product. The froth is repulped in a cleaner cell and refloated with no additional reagents. After one more cleaning, the product glass is over 99% pure.

Putting a system together

Knowing something about the key equipment needed, both to manufacture a homogeneous refuse fuel for industrial and utility steam generators and to recover basic materials from refuse, let's see how it all goes together. An example of what appears to be a well-designed system is the Solid Waste Recovery Project for the city of Ames, IA, which is expected to begin operations about midyear. It probably is the most advanced utility system of its type in operation or under construction.

The $5.5-million facility will convert the combustible fraction of approximately 1000 tons/week of municipal refuse into a supplementary fuel for three existing boilers in the city's municipal power plant (see equipment list, p 86, for specifics on plant components). It will also recover some noncombustible materials. Realize that the city of Ames is responsible for its own refuse collection, as well as for its power generation.

The refuse-processing plant is located three blocks from Ames's central business district, and only 800 ft from the power plant. Trucks dump refuse on the floor of the processing facility, and a front-end loader pushes it onto a belt conveyor. Raw refuse is delivered, at the rate of 50 tph, to a shredder (similar to that shown in Fig 31), which reduces the maximum size of the feedstock to about 6 in. A magnetic separator (Fig 46) then removes most ferrous materials; the remaining refuse is conveyed to another shredder and reduced in size to 1½ in. or less. The shredders are identical, and each is capable of milling the raw refuse to the desired 1½-in. size in one pass.

This milling arrangement was selected to increase plant availability and reduce maintenance costs. Note that the entire waste stream can be diverted to and processed by the second shredder if the first unit is forced out of service. If the second unit is down, grate bars in the first machine can be changed to reduce the refuse to the desired size.

Milled refuse is air-classified (Fig 38) and pneumatically conveyed to a storage bin (Fig 41) at the power plant. From there, it is conveyed pneumatically to a tangentially fired boiler; one or both of the plant's spreader-stoker-fired boilers will burn the waste fuel if the primary unit is out of service.

Materials recovery. The heavy fraction from the air-classification system is passed through two more stages of magnetic separation before being dumped to a surge bin (8-hr capacity), which feeds the nonferrous-materials recovery system. Bear in mind that operation of nonferrous recovery equipment in no way affects fuel-preparation activities, and, if operating difficulties are encountered with it, the contents of the surge bin can be sent to landfill.

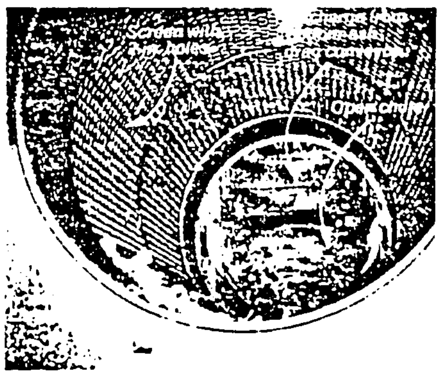


Fig 47

Trommel screens are sometimes used to remove scrap metal from the bottom ash in plants burning unprepared refuse

Nonferrous materials discharged from the surge bin flow into a trommel screen, which first removes less-than-¼-in. material—primarily sand and glass. This fraction can be rejected or recovered for municipal street maintenance and pipe-embedment activities. Scrap larger than ¼ in. is passed through a polyphase AC electromagnetic field, to separate nonferrous metals from other junk. The latter is sent to landfill. Nonferrous metals are then subjected to another eddy-current field, but in this case the power frequency is adjusted to remove just the aluminum can stock. The aluminum-free nonferrous stream and the aluminum-can stream are conveyed to storage to await recycling by others.

Utilities, industry burn refuse to generate power

Many existing coal-fired boilers can be modified easily to use prepared refuse as a supplementary fuel

Incineration plants at eight locations in the United States and Canada currently are producing steam in waterwall boilers solely from the combustion of municipal refuse. Some central-station and industrial power plants also are burning refuse in their boilers to generate steam, but in conjunction with conventional fossil fuels. Several more steam-generating municipal incineration projects and refuse-fired power plants are in various stages of design and construction; many others will be committed over the next few years as municipalities are forced to solve their burgeoning solid-waste disposal problems (table, below).

There are several avenues for cooperation between municipalities and private industry on refuse-to-energy projects. The most common: (1) Government can finance, own and operate the plant, with industry doing the design and construction; (2) government can finance and own a plant that industry designs, builds and operates; or (3) government can pay industry a fee for refuse it drops at a plant that is financed, owned, designed, constructed and operated by private enterprise.

Up to now, the first method generally has been preferred, primarily because industry did not want to get involved in politics or the garbage-disposal business. But the last method is now becoming quite popular. The reasons:

- Many landfills and conventional incinerators are polluting water and air, and are being closed down by EPA. Thus, municipalities may be faced with immediate building of environmentally acceptable facilities for the disposal of solid waste—at a time when financing often is extremely difficult.
- Some methods of financing available to private enterprise with municipal cooperation can be cheaper than general-obligation municipal bonds.
- Private enterprise has been successful both in recovering energy from solid waste and in selling the byproduct steam. Only two municipally owned plants (Quebec and Braintree) have been able to sell the steam they produce to help defray disposal costs.
- Personnel with the skills required for power-plant operation usually are not attracted by the low salaries traditionally paid to municipal workers.
- The profit motive generally enables private industry to operate plants of this type more efficiently, and with fewer personnel, than government.

Most municipalities are well aware of their responsibility for solid-waste management, and of the problems of financing, owning and operating disposal plants. This is, therefore, an ideal time for industrial and utility companies to approach government and determine how they might help both the community and themselves.

Power engineers should realize that there is no magic in burning garbage efficiently. All that is needed are well-designed systems and equipment, and experienced operators with a good knowledge of boiler operation and basic combustion principles. The combustion of municipal refuse is a natural extension of the technology that has been developed, by industry and the boiler manufacturers, to burn process solid wastes (see section beginning on p 66).

A look at the experience gained by others in burning refuse may help you avoid some of the common pitfalls in plant design. Discussion here will focus on those plants operating or under construction in the U S and Canada. European experience, where applicable to operation on this continent, generally has been factored into these designs, and is not presented separately.

Guard against corrosion

Two potential problems that must be given special consideration in the design of any boiler used for firing refuse—whether by mass burning or suspension firing—are fouling of heat-transfer surfaces and corrosion. All heating surfaces are subject to fouling from slag and flyash deposition, but the buildup of deposits can be minimized with proper furnace sizing, a suitable arrangement

Refuse-to-energy projects operating or planned [1]

Generate steam [2] for off-site use:

Location (Owner/operator)	Status
Montreal, Que., Canada (Muni)[3]	Op
Quebec, Que., Canada (Muni)	Op
Hamilton, Ont., Canada (Muni)[3]	Op
Harrisburg, PA (Muni)[3]	Op
Chicago, IL (Muni)[3]	Op
Nashville, TN (NPC)	Op
Braintree, MA (Muni)	Op
Norfolk, VA (U S Navy)	Op
Saugus, MA (PriC)	UCon
Portsmouth, VA (U S Navy)	UCon
Akron, OH (Muni)	DSC
Albany, NY [4]	DSC
Cleveland, OH (Muni)	FSC
Palmer Twp, PA (Muni)	FSC

Generate steam [5] to produce electricity:

Location [6] (Utility 7)	Status
St. Louis, MO (Union Electric)	Op [8]
Brockton, MA[9]	SS
Chicago, IL (Commonwealth Edison)	UCon
Ames, IA (Muni)	UCon
Bridgeport, CT (Northeast Utilities)	CAwd
Hempstead, NY (Muni [10])	CAwd
New Britain, CT (Muni)	CNeg
Monroe Cnty, NY (Rochester G&E)	CNeg
Lane Cnty, OR (Muni)	PDC
Memphis, TN (TVA)	PD
Hackensack Meadowlands, NJ (Public Service E&G)	FSC
Milwaukee, WI (Wisconsin Electric)	FSC
Wilmington, DE (Delmarva P&L)	US
Washington, DC (Pepco)	US
Montgomery Cnty, MD (Pepco)	US
Madison, WI (Madison G&E)	US
Los Angeles, CA (Muni)	US
Honolulu, HI (Hawaiian Electric)	US
Housatonic Valley, CT (Muni)	US

CAwd—Contract awarded. CNeg—Contract being negotiated. DSC—Design study complete. FSC—Feasibility study complete. Muni—Municipal government. NPC—Nonprofit corporation. Op—Operational. PD—Preliminary design underway. PDC—Preliminary design complete. PriC—Private corporation. SS—System shakedown in progress. UCon—Under construction. US—Under study.

[1]As reported by the U S Environmental Protection Agency, Oct 1974. [2]From processed or raw refuse in a waterwall boiler or waterwall incinerator. [3]Steam available for sale, but no contract signed yet. [4]City to own refuse processing plant which contractor will operate; state to own and operate steam-production facility. [5]From processed waste—that is, shredded refuse with heavy fraction (metals, glass, etc) removed or prepared refuse fuels in powdered, pellet or briquette form. [6]Location of refuse processing plant. [7]In some cases, the utility may not have signed a contract to burn the prepared refuse in its boilers, but it is participating in engineering and testing aspects of the project. [8]Demonstration plant operational, expansion planned. [9]Preparation facility here already has a major paper company under contract for about 70,000 tons of its fuel product over a 10-yr period. [10]Sale of electricity to Long Island Lighting Co.

Reverse reciprocating grates tumble refuse continuously

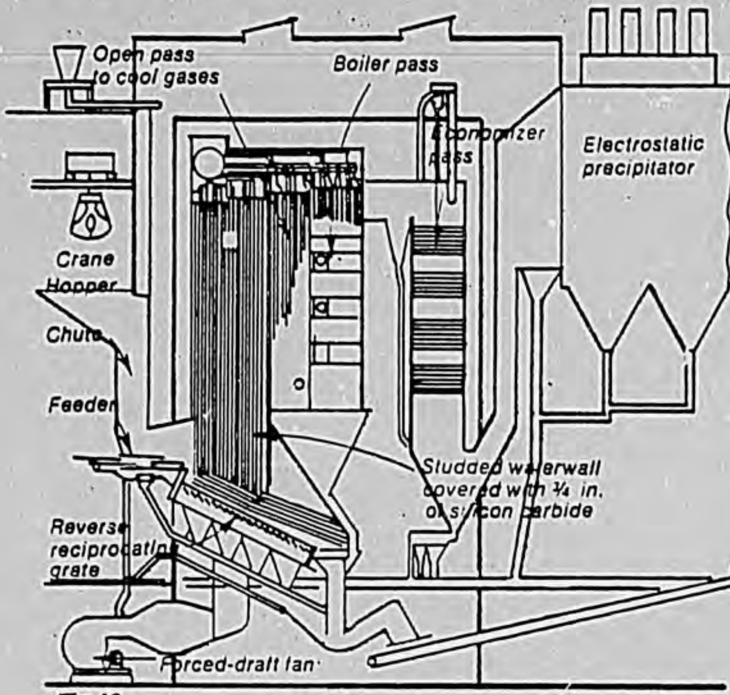


Fig 48

Operation of the Harrisburg and Chicago waterwall incinerators begins with unprocessed refuse being deposited in the stoker hopper by a crane (Fig 48). Waste material moves down through a water-cooled chute to a reciprocating feeder, which has staggered pusher blocks to prevent big clumps of refuse from being deposited on the grate (Fig 49). This design feature helps promote rapid ignition, thereby minimizing the formation of corrosive gases. The 7-ft-wide grate sections (there are three in each of these incinerators) are inclined at an angle of 26 deg, creating a gravitational downward flow of refuse over the grate area. In the section of grate closest to the feeder, furnace heat drives off excessive moisture from the waste so that, as it moves downward, ignition is relatively instantaneous. Note that the reverse reciprocating action of the grate (Fig 50) pushes the bottom layer of burning refuse back up the inclined bed, creating a tumbling action that insures complete burnout before the grate is traversed. The hydraulically driven, air-cooled grate bars are cast of a special chrome-steel alloy to maximize service life. The manufacturer estimates that, when the stoker/grate system is operated properly, grate bars in the hottest areas of the furnace should last about 20,000 hr. At the end of each grate section, an ash discharge roller with variable-speed drive controls the depth of the residue bed to assure that the grate is always covered

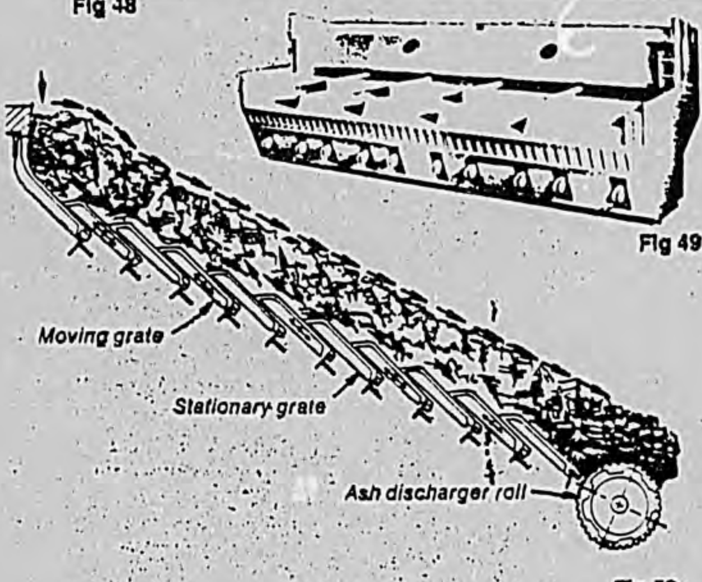


Fig 49

Fig 50

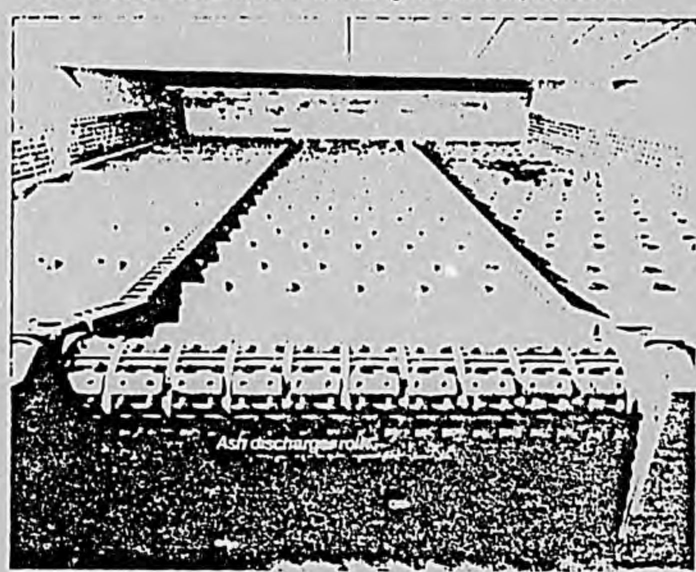


Fig 51

of heat-transfer surfaces, and correct use of boiler-cleaning equipment.

Proper furnace sizing means (1) providing adequate volume and residence time to insure complete burnout of combustible gases and solid particles, (2) absorbing enough heat in the furnace so the ash will be dry when it contacts boiler tubes, and (3) maintaining a temperature in the combustion zone that is hot enough to destroy odor-causing bacteria.

Heat-transfer surfaces should have wide spacing in convection passes—especially in the high-temperature zones—and in-line rows of tubes. Also, gas velocity should be low, and suitable cleaning equipment must be provided in the convection sections.

Although these criteria may appear as stumbling blocks in your efforts to burn municipal refuse in an existing boiler, remember that many units designed for coal already have some of these characteristics. To illustrate: Corner-fired, coal-burning steam generators normally can take up to about 20% of design heat input in the form of prepared refuse fuel with relatively little modification. Combustion is achieved with essentially normal excess air in a unit of this type because of furnace turbulence. Gas weight increases slightly, but existing fan capacity usually is adequate.

Serious gas-side corrosion always is a threat when a high percentage of the boiler heat input is from refuse. There are at least three types of corrosion that must be guarded against: (1) corrosion precipitated by a reducing environment in the furnace, (2) halogen corrosion, and (3) low-temperature corrosion.

The first is caused by the products of partial combustion that always exist in a furnace with a reducing atmosphere. It occurs primarily in mass-burning installations. Bear in mind that a reducing environment can exist locally in a furnace that is supplied with as much as 100% excess air, or even more, as a result of stratification or improper distribution of air or fuel. Carbon monoxide and hydrogen sulfide, which may be formed under these conditions, attack furnace tubes and remove the protective layer of iron oxide, exposing tube metal to further corrosive activity.

Another potential problem that can be created by a reducing atmosphere is liquid-phase corrosion. It is caused by the attack on boiler tubes of sulfate, alkali and chloride compounds, which have lower fusion temperatures in the reducing environment.

Halogen corrosion has been recognized for years, but there is some dis-

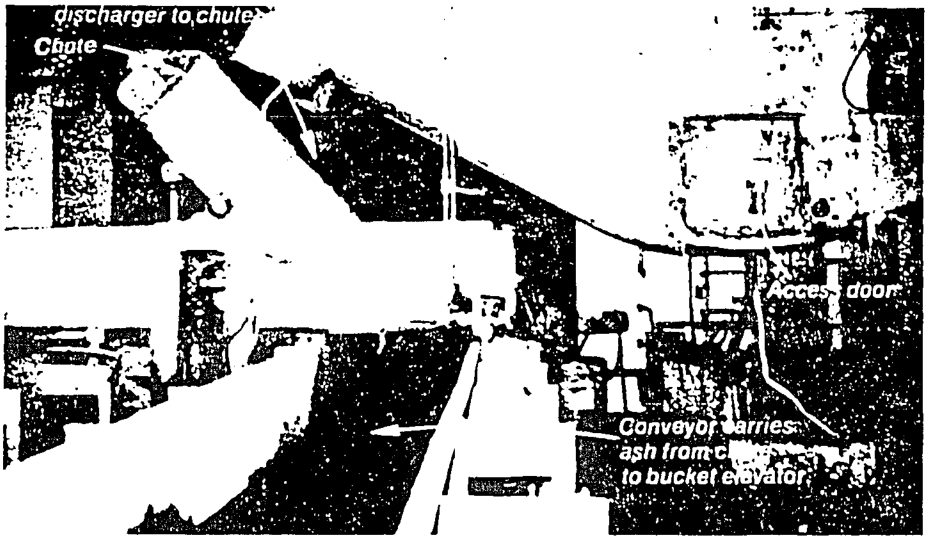


Fig 52

Fig 53

Residue leaving the Chicago and Harrisburg furnaces drops to a water-sealed ash discharger, where it is quenched. Occasionally, these devices become jammed with large objects, such as bed-springs, which are removed through the access door. At Harrisburg, objects bigger than a 1-gal paint can are removed after the discharger to prevent jamming of a bucket elevator (Fig 53)

agreement on its mechanism and on the temperature range in which it occurs. Tests conducted at a midwestern incinerator plant by Battelle Columbus Laboratories show that the corrosion rate of low-alloy steels is increased markedly as the amount of polyvinyl chloride (PVC) in the refuse, and the metal temperature of the sample, increase. PVC can contain chlorine in concentrations as high as 50%.

Low-temperature corrosion occurs when the flue gas contacts surfaces that are at temperatures below the dew point of corrosive constituents in the gas. Temperatures low enough to cause acid condensation may be found at the water-inlet end of an economizer if feedwater temperature is too low, at the cold end of an air heater, in particulate-removal equipment and on boiler outer casings.

Low-temperature corrosion also can be a problem during unit outages. When deposits are both corrosive and hygroscopic, the condition becomes more acute as the length of the outage increases. This is why the unit should be water-washed when a lengthy shutdown—such as for a weekend—is contemplated. Otherwise, the boiler should be kept hot by using an external source of heat.

As you can see, the three types of corrosion that may attack refuse-fired boilers are relatively complex and are influenced by many variables related to materials of construction, unit design, fuel composition and operating practices. Thus, it is generally unwise to extrapolate specific experience at another plant to your particular situation. If an existing boiler is to be used for burning refuse in conjunction with fossil fuels, you can obtain any necessary corrosion and deposit data easily by first inserting probes in areas of the boiler that are potentially subject to wastage and fouling, and then conducting test burns with prepared refuse. It is a good idea to discuss your plans with the boiler manufacturer before conducting tests.

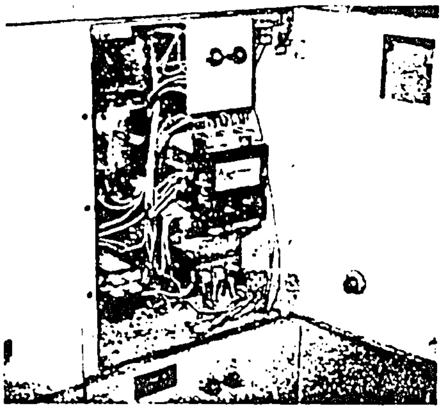


Fig 54

Motor-control centers should be located in areas where clean air is readily available, to prevent dust problems

Environmental considerations

The impact of refuse-fuel combustion on boiler emissions is another area that must be investigated thoroughly by engineers before a company commits itself to burning municipal wastes. For utilities and large industrial companies considering refuse as a supplementary fuel, an important part of this study will be to determine the applicability of various emission standards. Example: The US Environmental Protection Agency (EPA) does not now have any regulations that apply specifically to large steam generators (250-million Btu/hr heat input and above) which burn fossil and refuse fuels in combination. This situation may only be temporary, however, because the government is conducting a study to determine whether additional regulations are necessary.

Just how refuse firing will affect boiler operation under existing standards depends on whether the boiler is considered by EPA to be a new source or an existing source. For new sources—defined as those units installed after Aug 17, 1971—two of the basic references you will need are the "Standards for New Stationary Sources," originally promulgated Dec 23, 1971, and the amendment to these standards that was

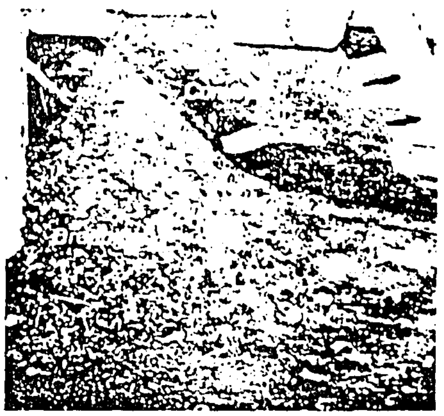


Fig 55

Conveyor systems, when improperly designed, can cause problems—for example, spillage at transfer points (Fig 55) and droppings from carryover (Fig 56)

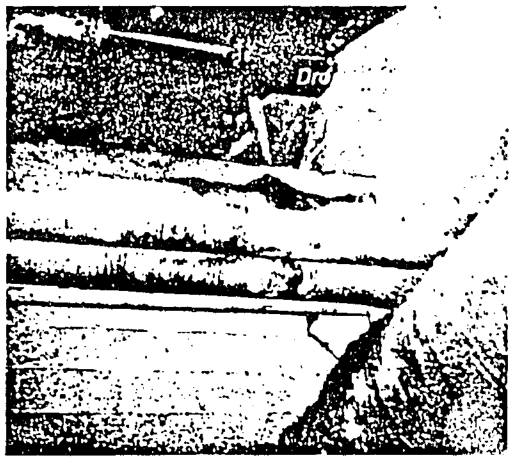


Fig 56

High-resistance grates offer long life

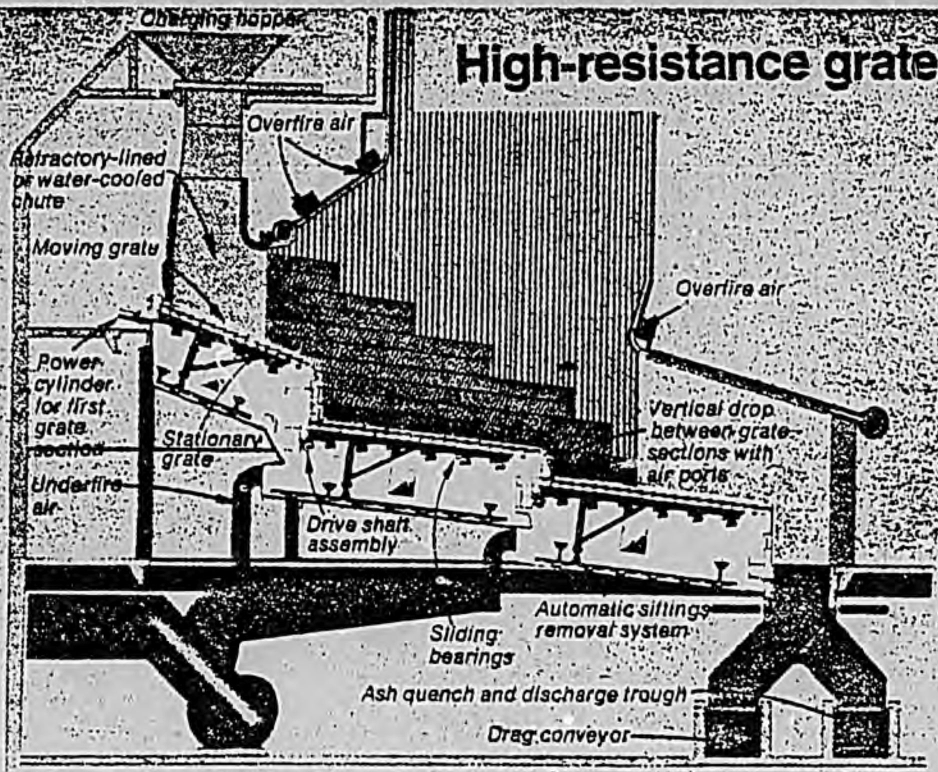


Fig 57

Mass-burning refuse-to-energy plants in Nashville, TN, and Portsmouth and Norfolk, VA, have reciprocating-grate systems with three or more grate sections in series, as shown at left. Like other mass-burning systems, raw refuse dumped into a charging hopper passes through a refractory-lined or water-cooled throat and drops onto the first or drying grate. Most combustion takes place on the middle grate in a three-grate system; final burnout occurs on the third section. Alternate rows of grates reciprocate, so refuse is agitated continuously and optimum burning conditions are maintained. Combustion air is fed to the underside of the second and third grate sections. Air distribution is through relatively small, Venturi-shaped ports in the grate castings. Resistance to air flow is high with this design, so that if blowholes occur, the remainder of the grate will not be air-starved.

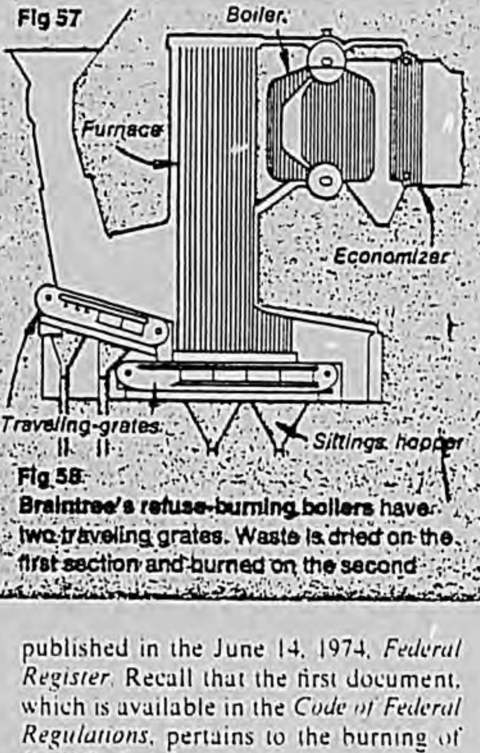


Fig 58

Braintree's refuse-burning boilers have two traveling grates. Waste is dried on the first section and burned on the second

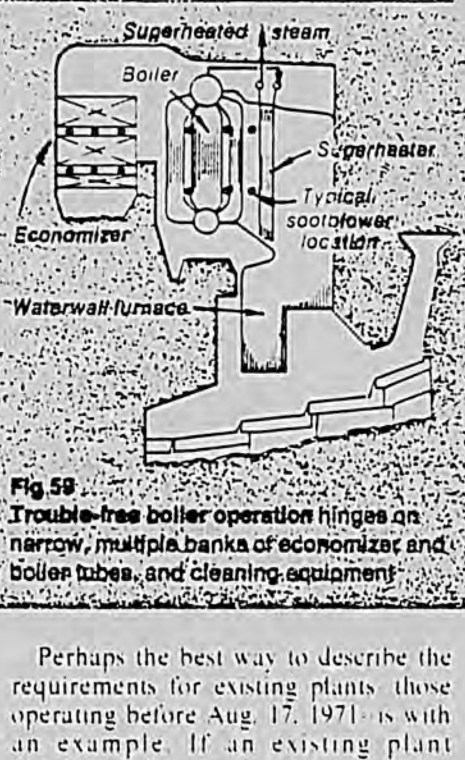


Fig 59

Trouble-free boiler operation hinges on narrow, multiple banks of economizer and boiler tubes, and cleaning equipment

Fig 60

Grate pluggage and wear could have been prevented here by not reducing underfire air flow below manufacturer's limits

published in the June 14, 1974, *Federal Register*. Recall that the first document, which is available in the *Code of Federal Regulations*, pertains to the burning of fossil fuels only.

The June 14 amendment says that, while new sources must be capable of meeting the Dec. 23 regulations (as revised) when burning the fossil fuels for which they were designed, they are exempt from these standards if other combustible materials are burned in conjunction with a fossil fuel.

Pollution-control equipment must perform well enough, however, so the region in which the plant is located will still meet ambient-air-quality standards specified by the Clean Air Act. Further, don't forget that state and local regulations are still applicable, and they may pertain to the combined combustion of fossil fuels and other combustible materials.

Perhaps the best way to describe the requirements for existing plants—those operating before Aug. 17, 1971—is with an example. If an existing plant switches fuels, emissions caused by the combustion of the new fuel cannot increase beyond levels specified for the original fuel—that is, unless *new-source* performance standards for the *new fuel* are not exceeded. To illustrate: If the conversion is from gas to oil, plant discharges undoubtedly will increase, and the utility has the option of meeting either the existing emission requirement for gas firing or the new-source limits for oil firing.

The June 14 rule says, in effect, that switching from a fossil fuel to combination fossil-fuel/refuse does not constitute a "change" in fuels; consequently, new-source performance standards do not apply. The plant must still, however, comply with applicable state and local codes, and must not cause ambient air quality to drop below levels authorized for the region.

Mass-burning experience

The Harrisburg and Chicago Northwest incinerators have nearly identical fuel-burning and steam-generating systems (Figs 48-51). Principal advantage of the reciprocating grate used in these installations, and similar grates installed at other plants, is that they produce a nearly sterile ash from raw refuse. A major disadvantage of mass burning is that the rate of steam production, and the firing pattern of the refuse, are relatively uncontrollable.

Today, most of the steam produced at both locations is condensed without doing useful work, although a little is used to drive plant auxiliaries. At Harrisburg, however, there are plans for using steam to heat-treat and dry sludge

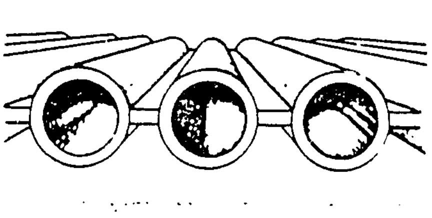


Fig 61

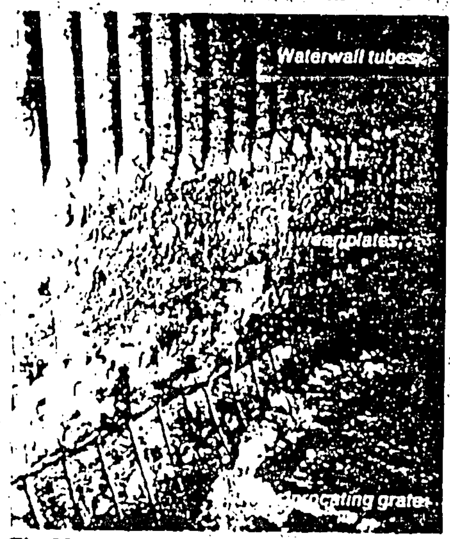


Fig 62

Furnace walls in modern refuse-burning plants typically are constructed of all-welded finned-tube panels. These enclose the furnace in a solid, gas-tight steel envelope, assuring maximum efficiency and minimum maintenance (Fig 61). A layer of wear blocks (Fig 62), or refractory, over tubes near the grate prevent damage

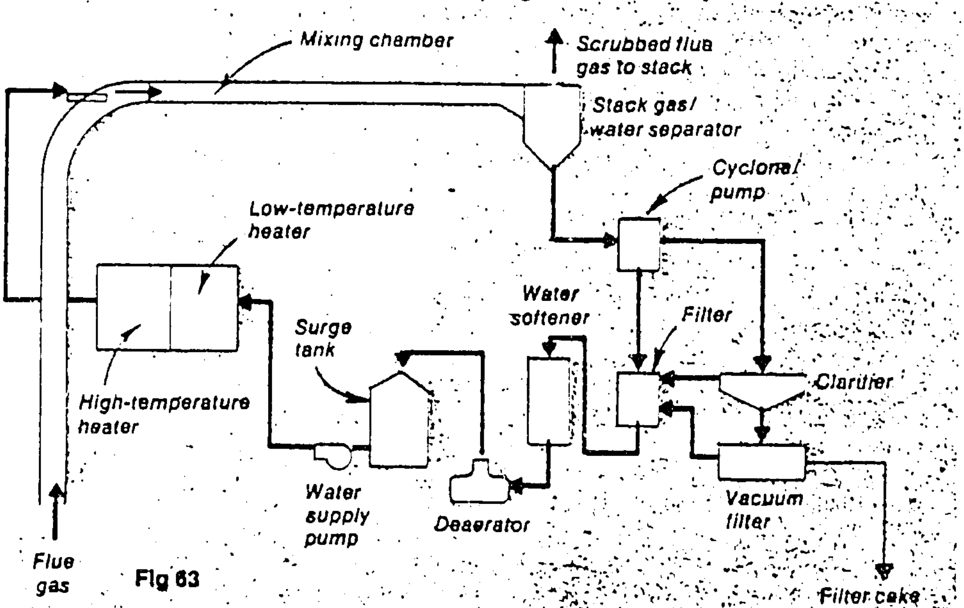


Fig 63

High-energy scrubber system may replace existing air-pollution-control equipment at the Nashville Thermal Transfer Plant some time in 1975. The original scrubber and the unit operating now are not capable of meeting the clean-air laws

Chemical composition of typical municipal refuse

Category	Avg	Max	Min
Heating value, Btu/lb			
As received	4981	7593	2293
Dry	7248	13,002	6602
Moisture, wt %			
Total	31.2	66.3	11.1
Inherent	1.2	2.62	0.36
Ash, wt %			
As received	15.8	21.4	7.6
Dry	23.1	33.0	14.3
Sulfur, wt %			
As received	0.10	0.28	0.04
Dry	0.16	0.36	0.07
Chlorine, wt %			
As received	0.40	0.94	0.14
Dry	0.58	1.14	0.31
Common salt, wt %			
As received	0.30	0.55	0.11
Dry	0.45	0.76	0.33
Ash analysis, wt %			
P_2O_5	1.52	2.04	1.06
SiO_2	49.6	56.7	39.9
Al_2O_3	11.3	26.9	6.1
TiO_2	0.89	1.52	0.07
Fe_2O_3	7.89	22.2	3.03
CaO	13.0	15.8	9.09
MgO	1.55	2.32	0.64
SO_3	1.54	2.72	0.73
K_2O	1.78	2.91	1.07
Na_2O	8.70	19.2	3.11
SnO_2	0.05	0.10	0.02
ZnO	0.43	2.25	0.19
CuO	0.28	1.23	0.06
PbO	0.20	0.62	0.12

in a nearby sewage-treatment plant. The dry sludge will then be conveyed pneumatically back to the furnace and burned in suspension. Bear in mind that the production of steam does serve a purpose: It reduces the volume of flue gas, thereby decreasing the cost of gas cleanup from incinerator plants.

Tube damage. Harrisburg and Chicago boilers have performed well except for tube failures. In the Pennsylvania plant, the pendant superheaters were damaged by particulate impingement on the mild-steel tubes and had to be replaced. The Harrisburg boiler design has since been modified by the manufacturer to eliminate ash erosion problems, as well as problems associated with the fouling of heat-transfer surfaces, in later installations. The new design, which reportedly has performed well in Europe, is shown in Fig 48.

Tube failures in the Chicago boilers, caused by water impingement, have been eliminated by modifying the sootblower drain system.

When some large waste objects—such as mattresses—are dropped into the boiler hopper by the crane operator, they do not burn completely, and often jam in the ash discharger (Fig 52). Rectifying this problem can take up to a couple of hours, in an unpleasant environment. Difficulties such as this are being minimized by educating truckers and crane operators to sort out big objects for preshredding.

Maintenance costs for Harrisburg's bulky-refuse hammermill were reasonable over the first year of operation. Engineers found that rotating the hammers and cutter bar every three months, and replacing them every six, yields optimum results.

Conveyors and other materials-handling equipment can be the source of many headaches if they are not designed properly for refuse-to-energy systems. Here are some things you should consider:

- Specify size and capacity of all equipment to handle the largest payload anticipated. This was not done in one system at Harrisburg, and extra work has resulted. To illustrate: Buckets on the bucket elevator are too small for some objects discharged from the furnace. Thus, a man must be used full time at the ash discharger to remove metal larger than about the size of a paint can (Fig 53). In the Chicago ash-handling system, jamups occur in the hopper funneling ash from the discharge conveyor to the disposal truck. A man must be stationed at the hopper to remove oversize objects and operate the hydraulic gate.
- Arrange conveyor transfer points in such a manner as to minimize spillage (Fig 55).
- Install an air-wash or water-spray system to continuously clean residue from the conveyor belt as it discharges cargo. This prevents carryback and housekeeping problems such as that shown in Fig 56.
- Specify shear pins for bucket elevators and conveyors of all types. Failure

to do so can lead to damage if refuse jams the machine while it is operating.

■ Require wear-resistant parts and sealed bearings on all equipment that handles flyash, to minimize maintenance costs

■ Provide good visibility and a comfortable environment to keep crane operators alert. They are the first line of defense against outages caused by poor fuel composition on the grate, or by jamups and damage from oversize objects in the refuse.

The salvage-fuel boiler plant at the U S Navy Public Works Center in Norfolk, VA, has been operating since 1967—longer than any other installation of its type in the U S. It produces 275-lb auxiliary steam for ships in port. As originally constructed, the plant had cyclone collectors for particulate control, but the more-stringent pollution-control regulations imposed over the last few years have necessitated the addition of electrostatic precipitators. This equipment, plus a new set of induced-draft fans, is expected to be operating early this year.

The new fans, which have a greater capacity than the units now in service, are expected to eliminate a grate-overheating problem—a cause of accelerated grate deterioration (Fig 60). This overheating at Norfolk has been traced to insufficient planning at the design stage—not to any problems with the stoker/grate system.

The original thinking was that solid waste from the Navy base would be comparable to municipal refuse in heat content. But its heating value turned out to be considerably higher, because there is a large amount of wood and paper in the waste stream. Result: The induced-draft fans selected initially could not handle the actual gas flow through the boiler under some operating conditions. Engineers, therefore, had to reduce underfire air to keep from pressurizing the furnace, and this is what created the overheating condition.

Despite the periodic instability of the furnace environment, there has been no evidence of tube corrosion or erosion in the two Norfolk boilers. Normal operating practice calls for maintaining furnace exit-gas temperature at about 1500 F, and for sootblowing, with steam, twice daily. Boiler passes are airlanced two or three times a year to eliminate deposits—such as clay—that are not removed by the sootblowers.

A shredder was installed at the plant late last year to mill the pilings, large packing crates and other oversize objects delivered for incineration. This machine, and the belt magnet positioned over its discharge conveyor (Fig 45), will help minimize carbon loss to the ash pit.

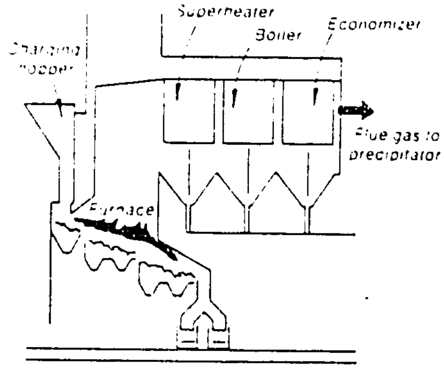


Fig 64

Flue gas flows from furnace straight through superheater, evaporator and economizer in boilers at Saugus, Quebec

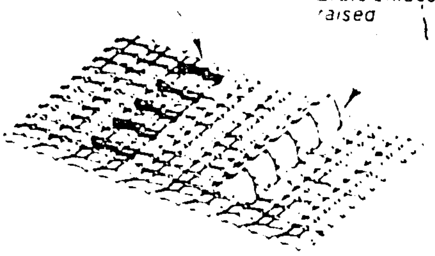


Fig 65

Blades in this burnout grate can be raised to break up lumps of clinker, thereby insuring complete combustion of refuse

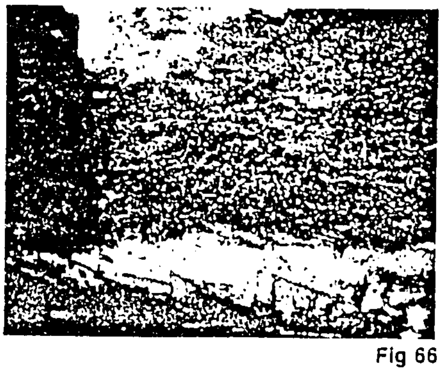


Fig 66

Slag buildup in refractory furnaces with uncooled walls can be troublesome. Waterwalls should extend to the grate

Nashville's Thermal Transfer Plant is producing steam and chilled water for commercial buildings in that city from the combustion of refuse. This facility has received some adverse publicity lately because of its scrubber problems. But this type of coverage in the popular press generally appears to be unjustified for a plant in its first year of operation.

The problem simply is this: The scrubbing equipment originally specified for the plant was of the low-energy type designed for conditioning air in climate-control systems, not for cleaning boiler flue gases. This became evident during equipment-performance tests last spring, and the consulting engineer thought the design error could be corrected by installing a scrubber of higher energy. The new unit by itself, however, is incapable of producing an effluent flue gas that will meet federal and local environmental codes. The fact that this medium-energy scrubber would not do the complete job was recognized before the equipment was installed, but it was the fastest and most practical way to overcome the gross deficiencies of the original unit.

It is hoped that the entire problem will be cleared up some time this year with the installation of more efficient gas-cleaning equipment. At press time, several systems were being evaluated. One was a high-energy scrubber that reportedly has performed well under conditions similar to those at Nashville (Fig 63). It introduces superheated water under high pressure into the scrubber chamber through a jet nozzle. Water that flashes into steam as it leaves the nozzle accelerates the remaining water droplets, which collide with, and remove pollutants from, the gas stream. If this particular system is selected, the interim scrubber will continue in use, to quench the flue gas before it enters the high-energy scrubber.

Most if not all of the remaining equipment at Thermal Transfer was designed conservatively, and no problems are anticipated. The furnace, for example, was sized for a maximum heat-release rate of only 17,000 Btu/cu ft-hr (Fig 59). Enough heat-transfer surface was included to drop the temperature of the gas entering the superheater below 1600 F, so slagging in the boiler bank would be minimized. Most of the furnace is of membrane-wall construction, consisting of 2½-in. tubes on 3-in. centers with a bar welded between the tubes (Fig 61). The section of waterwall nearest the grate is covered with refractory, both to protect the tubes and to reflect heat back onto the grate to improve burning. The boiler and economizer have a single gas pass and in-line tubes, to minimize tube erosion and plugging.

Braintree has the only mass-burning traveling-grate combustion system in the U S (Fig 58). Refuse is handled, however, in the same manner as in other plants: Packer trucks discharge their cargos into a large pit, and the raw waste is moved from there to the boiler hopper by a crane. Although the boilers are rated at only 30,000 lb/hr, the refuse has a high paper content, and operators are able to get as much as 40,000 lb/hr from each unit without any adverse results. Corrosion of the electrostatic precipitators was a problem in the past, but it turned out to have been caused by operator error. The plant was shut down cold on weekends.

Waterwall incinerators at Quebec and Saugus essentially are of the same design (Fig 64). Like most of the other

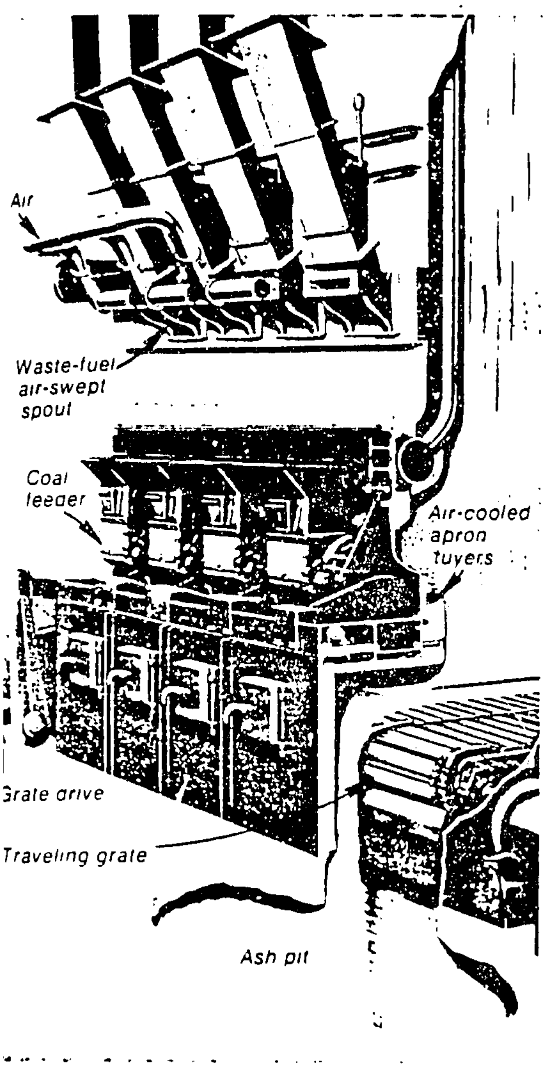


Fig 67

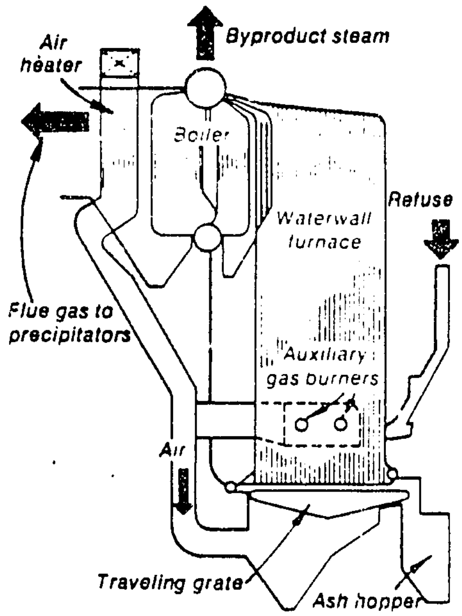


Fig 68

Prepared municipal refuse, like many process wastes, can be burned in most industrial boilers capable of handling solid fuels (see pp S-2-S-7). Some equipment changes probably will be necessary, but generally they will be relatively straightforward. To illustrate: The spreader-stoker-fired unit in Fig 67 was equipped to burn waste by adding refuse feeders in the furnace wall, and a separate fuel-supply system to handle the additional fuel. The same type of steam generator also can be designed to burn refuse as the primary fuel (Fig 68)

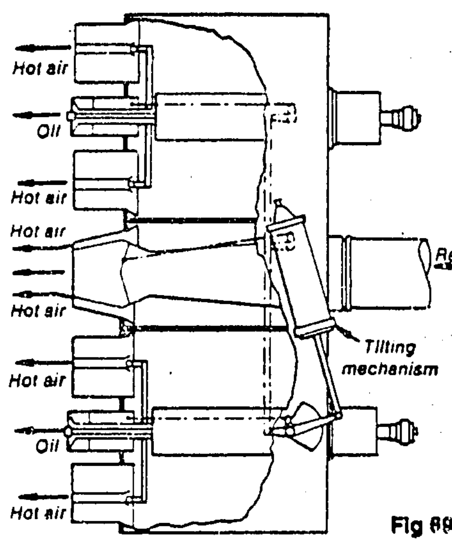


Fig 69

Tangential firing systems burn refuse in suspension without a burnout grate. Oil or coal must be the primary fuel, however

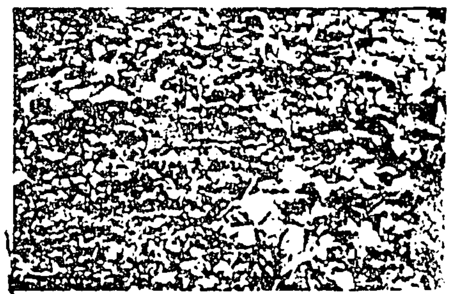


Fig 70

Quality of bottom ash decreases markedly when refuse is burned in suspension with coal. Photo is of a utility ash pond

mass-burning plants, they also burn refuse on reciprocating grates (Fig 65).

Designers of the Quebec plant, looking to minimize the threat of forced outages from corrosion damage, selected a boiler-cleaning system that uses rapping assemblies. The same type of equipment is being installed at Saugus. Experience with rappers thus far in Canada has been promising. Slag deposits, but not the protective iron-oxide coating, are removed from the tubes. Note that similar types of rapping equipment and systems have been used for years to clean waste-heat boilers in the metallurgical industry.

Montreal's combustion system is the same as that used at Saugus and Quebec, but the boiler is of an older, three-pass design. Also, furnace waterwalls only extend to within about 15 ft of the grate; from that point to the grate there is an uncooled refractory wall. Initially, the hot wall caused massive accumulations of slag in the furnace. Sometimes, in fact, the 10-ft-wide furnace was bridged completely. This condition was rectified by installing water nozzles in furnace walls to cool the slag and prevent excess buildup (Fig 66).

Suspension firing

Experience at Union Electric Co's Merimac plant has shown conclusively that prepared municipal refuse can be used as a supplementary fuel in large pulverized-coal-fired boilers. Design of what is currently thought to be the optimum method of preparing refuse for utility boilers evolved from the St Louis experiment. It is described on p 78 for a similar project in Ames, IA.

The fuel-preparation system is the key to successful suspension firing. The only modifications that must be made to the boiler are the addition of refuse-burning ports. For the Merimac boilers, which are tangentially fired, one port is installed in each corner of the boiler, between the two middle coal burners. When prepared refuse is burned at a constant rate, combustion controls on the boiler automatically vary the rate of coal firing to maintain the heat input of the unit. If for any reason the boiler trips suddenly, an electrical interlock immediately stops feeding the refuse.

Here is some of Union Electric's experience in burning shredded, air-classified municipal refuse:

- Refuse firing rates equal to about 20% of the total heat input appear to be practical for coal-fired units. There is no indication of furnace slagging or carryover of unburned material to the convection sections under these conditions. For oil firing, the boiler manufacturer thinks the limit on refuse heat input should be reduced to 10% of the total, because oil burning does not produce enough ash to absorb corrosive elements of the flue gas (Fig 69).
- There may be a slight increase in boiler emissions caused by refuse combustion, but no final conclusions on this have been reached yet.
- Milled refuse (1) does not decompose, (2) is free of disease-causing pathogens, and (3) attracts no rats, skunks, flies, etc. It has a light musky odor, which can be eliminated by deodorization if desired.
- Refuse tends to mat and compact when left in storage, particularly if it is over about 20 ft deep. Matting results in reduced and erratic bin flow, but the problem is not serious.
- The small amount of glass, fine metals, sand and other abrasives not removed by air classification cause wear

problems at bends in pneumatic conveying systems. Replaceable wear-back elbows should be used in these areas.

- The volume of bottom ash increases substantially with refuse firing (Fig 70): actual quantities have not been determined, but two to three times the normal amount of ash-sluicing usually is required. Foreign material in the ash hopper also tends to jam air-lock feeders. Better burnout can be obtained by milling refuse to a smaller size, and by admitting refuse at a higher point in the furnace.

Hamilton has the only refuse-fired steam generators in which part of the waste is burned in suspension and the remainder on a traveling grate (Fig 68). Refuse is dumped in a live-bottom storage pit (Fig 27), and is conveyed from there to one of four vertical hammermills (Fig 36), arranged in parallel. The pulverizers reduce the refuse to about a 2-in. maximum size. Ferrous materials are then removed, and the remainder of the waste stream is conveyed to storage by belt conveyor. Another belt conveyor reclaims the shredded refuse from storage and transports it to the two boilers, where swinging distributors feed the material via chutes to air-swept spouts (Fig 15). This system is very similar to some systems that are used in industry for burning solid process wastes.

One aspect of the Hamilton design philosophy that differs from other refuse-to-energy plants is found in the shredding operation. Where most mass-burning systems have heavy-duty shredders to reduce the size of oversize items, Hamilton has only mills designed for relatively light-duty operation. Large objects, or those difficult to mill—such as rugs, tires, etc—are picked manually from the conveyor just before the pulverizers, and are sent to landfill. Reason: A cost study revealed this was more economical than installing larger shredders, which have increased power requirements and generally, higher maintenance costs.

Hamilton has had its share of problems, too, but most of these have been mentioned earlier in connection with experience at other plants.

Construction is expected to begin on at least two other refuse-to-energy plants shortly: one for the city of Akron, OH, and the other for the town of Hempstead, NY. The Akron plant (Fig 71) will be similar to that at Hamilton; the Hempstead facility will be the first commercial-size plant using wet fuel preparation (Fig 72). A pilot plant of this type is operating in Ohio.

Principal equipment in refuse-fired power plants operatin

Solid waste recovery system, Ames, IA

Owner ... City of Ames
Consulting engineer ... Gibbs, Hill, Durham & Richardson Inc
Expected startup ... June 1975
Primary-shredder feed conveyor—*7 ft wide* ... Mayfran Inc
Shredders, 2 ... American Pulverizer Co
One primary, one secondary; each 50-tph capacity, 5-ft-diam wheel × 7.5-ft rotor; 1000-hp, 4160-V, 720-rpm motor drive
Shredder discharge conveyors, 2 ... Rexnord, Carrier Div
One per shredder; each oscillating type, 6 ft wide, 15-hp motor drive
Second-stage feed conveyor (standby) ... Rexnord, Carrier Div
Vibrating type, 4 ft wide, 7.5-hp motor drive. Normally, an inclined belt conveyor, 5 ft wide, would be used to convey refuse to the second shredder
Magnetic-metal separators, 3 ... Dings Co
One 5 ft wide, two 2-ft-wide magnetic belt pulleys
Air classification system ... Rader Pneumatics Inc
Includes one 600-cu ft surge bin complete with scalping roll and flight conveyor; vibrating feeder, 8 ft wide × 10 ft long; refuse conveying pipe, 42 in. diam; cyclone separator, 14 ft diam × 35.5 ft high; exhaust fan with 200-hp motor drive, etc
Pneumatic conveying systems, 5 ... Pneumatic Systems Inc
Process plant to storage: One system consisting of a positive-displacement blower rated 6545 cfm at 4.53 psi, 200-hp motor drive; inlet silencer; piping; feeder; cyclone separator, etc. Storage to boilers: Four identical and separate systems each consisting of a rotary positive-displacement blower rated 2390 cfm at 3.51 psi, 60-hp motor drive; silencer; feeder; inlet feed chute; fluffing roll, etc
Refuse storage bin—*500-ton capacity, 84 ft diam* ... Atlas Systems Corp
Noncombustibles separation system ... Combustion Power Co
Separation-system conveyors, 12—*Various sizes* ... Fairfield Engineering Co
Separation-system bucket elevators, 5 ... Fairfield Engineering Co
Boilers (existing), 3 ... Combustion Engineering Inc, Riley Stoker Corp, Union Iron Works Co
One 360,000 lb/hr at 900 psig/900 F with tangential burners and electrostatic precipitator; one 125,000 lb/hr at 725 psig/825 F with traveling-grate spreader stoker and multiple-cyclone dust collector; one 95,000 lb/hr at 710 psig/825 F with traveling-grate spreader stoker and multiple-cyclone dust collector

Solid waste utilization system, St. Louis, MO

Owner ... City of St. Louis/Union Electric Co
Consulting engineer ... Horner & Shifrin Inc
Commercial operation ... April 1972
Equipment at City of St. Louis processing facility:
Raw-refuse receiving conveyor—*84 in. wide* ... Te-Co Inc
Belt conveyors ... Continental Conveyor Co
Vibrating feeders and conveyors ... Borg-Warner Corp, Stephens-Adamson Div
Shredder ... Gruendler Crusher & Pulverizer Co
5-ft-diam wheel × 6.7-ft rotor, 1250-hp motor drive.
Air classification system—*45-tph capacity* ... Rader Pneumatics Inc
Pneumatic transport equipment ... Rader Pneumatics Inc
Storage bin—*300-ton capacity* ... Miller Hofft Inc
Nuggetizer (hammermill for densifying ferrous scrap) ... Eidal Corp
Equipment at Union Electric Co's Meramec Station:
Receiving bin—*100-cu yd capacity* ... Miller Hofft Inc
Pneumatic transport equipment ... Rader Penumatics Inc
Storage bin ... Atlas Syetams Corp
Boilers (existing), 2 ... Combustion Engineering Inc
Each 925,000 lb/hr, single-reheat type with tilting tangential burners (at four elevations in each corner of the furnace) and electrostatic precipitators. The furnace is about 28 ft x 38 ft in cross section, with a total inside height of about 100 ft

Solid waste reduction unit, Hamilton, Ont., Canada

Owner ... City of Hamilton
Consulting engineer ... Gordon L Sutin & Associates Ltd
Commercial operation ... Summer 1972
Incineration capacity ... 600 tpd
Refuse-pit size ... 40 ft × 80 ft × 30 ft deep
Refuse-pit apron conveyors, 4 ... Rex Chainbelt Ltd (Can)
Pulverizers, 4—*Each vertical-shaft type, 200-hp motor drive* ... Heil Co
Belt conveyors ... Rex Chainbelt (Canada) Ltd
Magnetic-metal separators, 2 ... Eriez Magnetics, Dings Co
Shredded-refuse storage bin—*70 ft diam* ... Atlas Systems Corp
Shredded-refuse fuel-supply systems, 2 ... Detroit Stoker Co
Each (one per boiler) consists of a swinging distribution spout and three parallel pneumatic chutes for injecting refuse into the boiler
Traveling grates, 2—*One per boiler* ... Detroit Stoker Co
Boilers, 2 ... Babcock & Wilcox Ltd (Can)
Each 100,000 lb/hr at 250 psig (saturated); gas temperature at economizer outlet, 590 F; efficiency, 71%; feedwater temperature, 227 F; excess air leaving the boiler, 37%
Electrostatic precipitators, 4 ... Babcock & Wilcox Ltd (Can)
All Lurgi design; two in series per boiler; maximum particulate emissions, 0.08 lb/1000 lb of dry flue gas at 50% excess air

Thermal transfer plant, Nashville, TN

Owner ... Nashville Thermal Transfer Corp
Consulting engineer ... I C Thomasson & Associates Inc
Commercial operation ... April 1974
Incineration capacity ... 720 tpd
Stoker/grate systems, 2—*One per boiler* ... Detroit Stoker Co
Boilers, 2 ... Babcock & Wilcox Co
Each 135,000 lb/hr at 400 psig/600 F; gas temperature at economizer outlet, 537 F; efficiency, 67.3%; feedwater temperature, 240 F; excess air leaving the boiler, 84%; air-pollution control device, wet scrubber

Salvage fuel boiler plant, Norfolk, VA

Owner ... U S Navy
Consulting engineer ... Metcalf & Eddy Construction Engineers
Commercial operation ... January 1967
Incineration capacity ... 360 tpd
Refuse-pit crane—*3.5-ton; 2-cu yd capacity* ... Harnischfeger Corp
Bulky-refuse shredder ... Jeffrey Manufacturing Co
Motor-driven horizontal hammermill; 30-tph capacity
Stoker/grate systems, 2—*One per boiler* ... Detroit Stoker Co
Boilers, 2 ... Foster-Wheeler Corp
Each 50,000 lb/hr at 275 psig (saturated). Approximate gas temperatures, F: furnace exit, 1680; boiler outlet, 580. Auxiliary oil burner capacity, 50,000 lb/hr. Sootblowers: one retractable unit between furnace slag screen and boiler bank, two fixed-position units in boiler bank
Dust collectors, 2 ... Research-Cottrell Inc
Each (one per boiler) is involute multiple-cyclone type, limits dust loading to 0.85 lb/1000 lb of dry flue gas adjusted to 50% excess air
Electrostatic precipitators, 2 ... Research-Cottrell Inc
Drag conveyors for bottom ash and flyash—*One each* ... Beaumont Birch Co

Refuse disposal boiler plant, Portsmouth, VA

Owner ... U S Navy
Consulting engineer ... Day & Zimmerman Inc
Expected startup ... Fall 1975
Incineration capacity ... 160 tpd
Stoker/grate systems, 2—*One per boiler* ... Detroit Stoker Co
Boilers, 2 ... E Keeler Co
Each 30,000 lb/hr at 115 psig (saturated); auxiliary oil burner mounted in furnace; air-pollution control device, electrostatic precipitator

How to design boiler controls for waste fuels

Waste fuels can no longer be wasted. Control systems must be designed to get the best possible efficiency and capacity while displacing as much prime fuel as possible

By **Frederick D Gelineau,** Foxboro Co

Waste fuels are usually fired by base-loading them manually at some level determined by the operator, and then responding to load-demand changes by manipulating the prime fuel, usually gas or oil. Because much of the load is carried by a fuel that is thought to cost nothing, there is often little attempt to minimize prime-fuel usage or to optimize efficiency. And, as might be expected, the operator often leaves himself plenty of margin for error by burning much more prime fuel than is really needed.

Procedures must now be changed. Today what's important is displacing as much prime fuel with waste fuel as possible, maximizing overall boiler efficiency and capacity, and keeping stack emissions within regulated limits. Reaching for these goals impacts directly on basic boiler-control techniques. It creates a need for optimization over and above the normal control function, and sometimes causes the boundary between boiler control and economic optimization to become unclear or even to disappear completely.

Simple conventional feedback control loops cannot provide acceptable performance. Additional feedforward techniques must be incorporated using analytical or other measurements to anticipate and compensate for variations in the effects of different fuels. Some of these functions can best be performed by analog control, while others can be done equally well by analog or digital control. However, some are clearly better handled digitally or cannot be handled by analog control at all. The specific hardware configuration will have to be chosen on the basis of the application. The best control configuration usually contains both analog and digital elements, though analog-only and digital-only control systems have been successfully used.

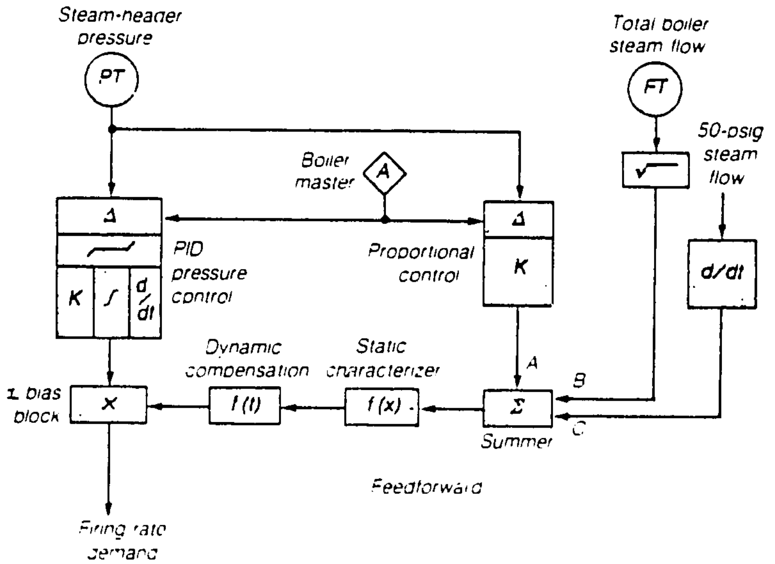
Since the aim is to minimize or eliminate the consumption of prime fuel, the waste fuel must be manipulated to control steam-header pressure. Waste fuels are inevitably difficult to handle, and problems may be encountered in any or all of the following areas:

- Conveying and distribution.
- Combustion stability.
- Dynamic response.
- Variable properties.
- Measurability.
- Toxicity.

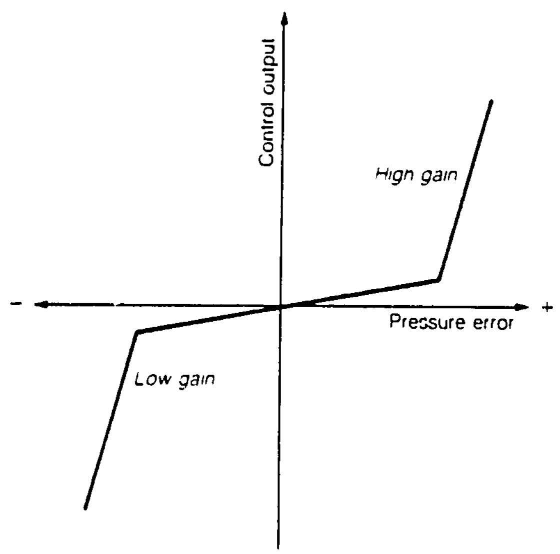
It is important to identify all of the problems of a particular waste fuel so that the controllability of the plant can be evaluated. But, in any event, expect controllability to be much less than for the oil- or gas-fired plant, and the control systems to be more complex.

Steam-pressure control

In an oil- or gas-fired plant, simple proportional-plus-integral (P + I) feedback control is sufficient to control steam pressure. The oil- or gas-fired boiler is stable and quick to respond. Relatively severe load transients can be absorbed easily, with minimum long-term upset to steam pressure.



1. Control system for firing solid-waste fuel has two feedforward loops whose purpose is to anticipate sudden changes in demand, fuel properties, or other boiler-side disturbances



2. Control system has two levels of gain. High gain comes into play only when large steam-pressure error signals are detected

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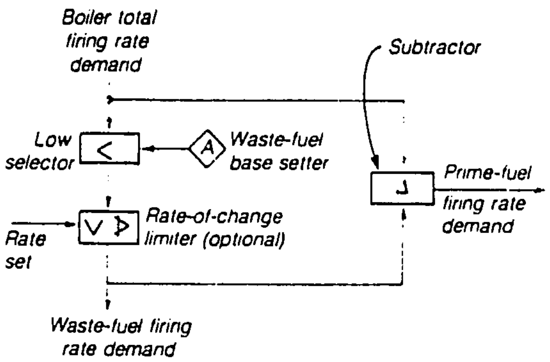
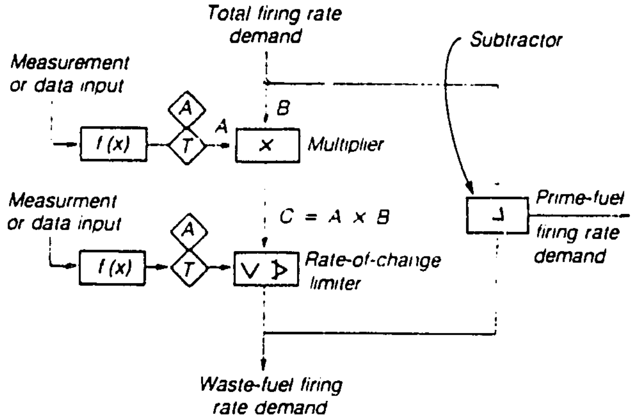


3. Waste fuel base-loaded, prime fuel modulated. This control-system subcircuit sets the firing-rate demand for the prime fuel



4. Waste/prime fuel ratio controlled. Ratio is set by the multiplier. Rate-of-change limiter allows ratio to change during transients

The relatively poor dynamic response with waste fuel as the primary manipulated variable demands a fundamental change in the approach to steam-pressure control. In the past, no limitations were placed on process demands. It was the responsibility of the boiler plant to meet these demands, and no restraints were placed on either cost or transient loading. But transient loading of any thermal machine is inefficient, and waste-fuel-fired boilers are generally slow to respond. Thus, better coordination between steam user and supplier is needed.

User demands under normal operating conditions must be stabilized. This means better scheduling and coordination of batch processes and limiting the rate of change of all types of process demands. Also, under abnormal or emergency conditions, the system needs much more than feedback control of firing rate. Feedforward control from different parts of the steam-distribution system may help. Temporary steam venting and/or steam load shedding may also be needed. This may be done via high or low steam-pressure override controls that take emergency action during upset conditions.

A feedback/feedforward system recently used for steam-pressure control of a boiler firing a solid waste fuel is shown in Fig 1. To establish the firing-rate demand, a linearized measurement of boiler steam flow is fed through a summer, a static characterizer f(x), a dynamic compensator f(t), and a multiplier. The summer provides a feedforward corrective trim from two additional measurements. Input C is a feedforward derivative response from low-pressure steam flow to the process. Any sudden change in low-pressure steam is fed forward to the summer, where it is combined with the firing-rate demand to reflect the process-steam load change. Thus, the effect of the load change is sensed immediately, without the usual delay while it ripples up through the steam-distribution system.

Input A provides feedforward compensation for stored energy lost or gained as a result of changes in fuel heating value or any other boiler-side disturbance.

During steady state, any change in fuel heating value or manual fuel supply causes a change in steam flow and steam pressure. A signal proportional to the pressure deviation from setpoint is fed forward and combined with the firing-rate demand to minimize the effect of changing heat value of the fuel. This control also makes up for any surplus or deficiency of stored energy during load transients.

Static characterization is provided by f(x), which characterizes the feedforward steam-flow signal to the firing-rate demand. Dynamic compensation for over- or under-firing on a load change is provided by f(t), which is a lead/lag unit.

Control output vs header pressure error is shown in Fig 2. The proportional-plus-integral-plus-derivative (PID) control trims the firing-rate demand for changes in steam pressure from the setpoint. The error signal is characterized such that the control block gain during steady-state operation is relatively low and output changes slowly. This assures stable operation within the normal pressure band. For large steam-pressure upsets, the error signal is such that the control block gain is relatively high. This assures rapid restoration of pressure control to the low-gain region.

This configuration prevents the system from chasing every small pressure deviation, which would only exaggerate the small upsets typically caused by waste-fuel firing. Notice that the derivative mode is used on the pressure controller even though this is not normally considered applicable. Most pressure-control processes are for mass inventory control. Since this is an energy inventory-control process, as are most temperature processes, derivative control can be quite effective if the pressure signal is not noisy.

To attenuate characteristic noise, the pressure transmitter should be installed as if it were a flow transmitter. Locate it in as long a straight run of pipe as possible, and carefully deburr the tap. In addition, a snubber or length of capillary can be used in the sensing line.

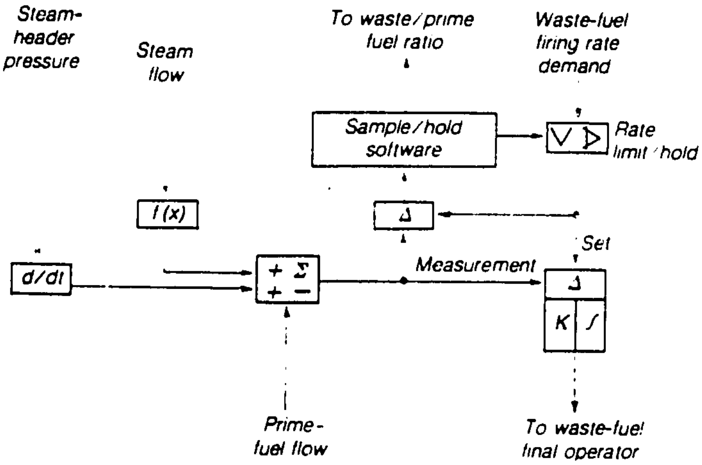
Combustion-control guidelines

The best combustion-control configuration depends entirely on how the waste and prime fuels can be used in the boiler. Four possible ways of using waste fuel are: (1) waste fuel fired alone; (2) waste fuel base-loaded, prime fuel modulated; (3) controlled ratio of waste to prime fuel; (4) prime fuel base-loaded, waste fuel modulated.

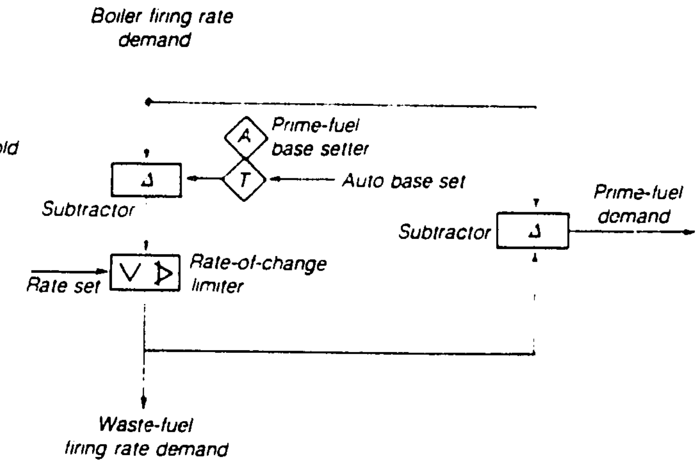
Waste fuel fired alone. This can be done only if sufficient waste fuel is available, if prime fuel is not needed to stabilize combustion, and if the dynamic response of the boiler with this fuel is compatible with the steam-load pattern of the plant. If these criteria are not met, then an alternative mode must be used.

Usually a parallel-metering system for air and fuel is best, largely because of environmental restraints. Typically, direct measurement of fuel flow is not possible, and inferential measurement must be used to correct for fuel inconsistencies. Some types of inferential measurement that have been used are belt-scale weight, fuel properties, and boiler heat balance.

Waste fuel base-loaded, prime fuel modulated. The level at which waste fuel can be base-loaded depends on its availability and the capacity needed from the boiler. Generally, the capacity of a boiler firing waste fuel is less than when firing prime. This may limit the amount of waste that can be base-loaded. A simple manual loading station may be used by the operator to set the base load, but a more desirable automatic control is shown in Fig 3. With this configuration, the base-load demand is the lower of either the total firing-rate demand or the operator-set base load. This ensures that, in the event of a sudden loss of steam load, the demand for waste fuel can be reduced accordingly. The subtractor calculates the difference between total firing rate and base load to find net



5. This subcircuit optimizes waste/prime ratio by calculating heat release from waste fuel and monitoring the difference between this and waste-fuel setpoint



6. Prime fuel base-loaded, waste fuel modulated. Subcircuit subtracts the prime-fuel base load from the boiler firing-rate demand to get waste-fuel demand

demand for prime fuel. The rate-of-change limiter is optional and is described below.

Controlled ratio of waste to prime fuel. A fixed ratio of waste to prime fuel may be necessary to stabilize combustion. This ratio may be set manually or by measurable, or known, fuel characteristics. For instance, combustion of wet hydrogen gas must be stabilized with oil or natural gas. Wet woodwaste may need an auxiliary fuel for stabilization and/or for handling transient loads.

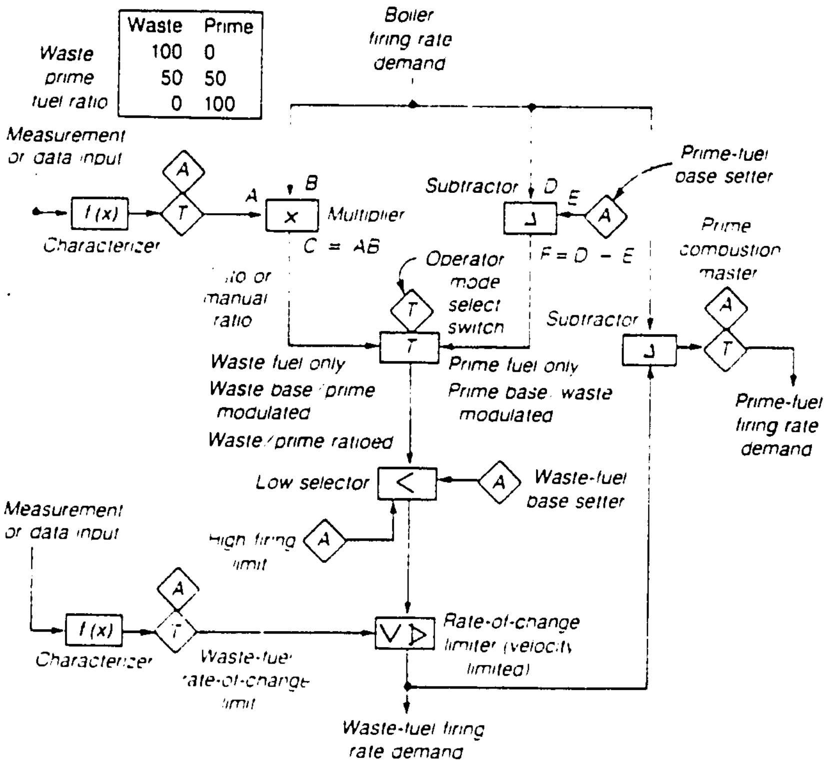
A system for fuel-ratio control is shown in Fig 4. Input A to the multiplier determines the proportion of the total firing-rate demand that is transmitted to the waste-fuel feed. At steady state, the subtractor sees the difference between total and waste-fuel demands, and calculates net prime-fuel demand.

During transients, the rate-limited waste-fuel demand is different from the steady-state value. Load changes are thus handled by the prime fuel, after which the waste-fuel firing rate ramps to the new steady-state demand.

The rate-limiting function may be either: (1) Not required. This would probably apply for gaseous or liquid wastes; (2) Required for both increasing and decreasing demand. This might apply to all types of solid-waste-burning units; (3) Required on increasing demand only. This might apply to wet solid-waste firing where little fuel is stored in the unit; (4) Required on decreasing demand only. This might apply if a relatively large quantity of fuel is stored in the unit.

An effective way to optimize the prime/waste fuel ratio is to close a control loop on waste-fuel-generated steam flow (Fig 5). Here the summing block calculates equivalent heat release from waste fuel by subtracting prime-fuel flow from characterized steam flow (steady-state total heat release) and adding rate-of-change of steam pressure (transient heat release). The summer output is the measurement into a controller whose setpoint is the waste-fuel firing-rate demand (which is rate-limited).

A second control algorithm (sample/hold software) monitors the deviation seen by the controller. If the deviation is excessive or sustained, it either rate-limits and/or clamps the waste-fuel firing-rate demand, and/or it increases the prime/waste-fuel ratio. In normal steady-state operation, the control action drives continuously towards maximum firing of waste fuel.



7. This control circuit can be set to modulate either waste or prime fuel in various modes or combinations. The setup on each is as follows:

Waste fuel only
- Waste/prime ratio on manual, set at 1.00
- Switch accepts input from left
- Waste-fuel base setter at 100%
- Waste-fuel rate-of-change on manual, set at minimum

Waste fuel base-loaded, prime fuel modulated
- Waste/prime ratio on manual, set at 1.00
- Switch accepts input from left
- Waste-fuel base setter set by operator
- Waste-fuel rate-of-change on manual, set at minimum

Waste/prime fuel ratioed
- Waste/prime ratio on auto or manual
- Switch accepts input from left
- Waste-fuel base setter at 100%
- Waste-fuel rate-of-change on auto or manual

Prime fuel only
- Switch in either position
- Waste-fuel base setter operator-set at 0%

Prime fuel base-loaded, waste fuel modulated
- Prime-fuel base setter operator-set
- Switch accepts input from right
- Waste-fuel base setter at 100%
- Waste-fuel rate-of-change limit auto or manual

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Prime fuel base-loaded, waste fuel modulated. This mode may be used if a constant ignition-stabilizing source is needed. It may also be used if the waste-fuel firing rate must be limited and load changes absorbed by the prime fuel (Fig 6). The prime-fuel base load is determined by the rate-of-change limit and the steam-load pattern. If the rate limit applies to both increasing and decreasing demand, then the value of the base load must be such that the prime-fuel firing rate can be decreased sufficiently during transients. If this setting is left up to the operator, he will probably burn too much prime fuel. The only way to optimize the amount of prime fuel burned is to calculate both the continuous running average load and the transient bandwidth. Obviously, this needs a computer or microprocessor, and cannot be done satisfactorily with analog control.

If the rate-limit is applied to decreasing demand only, then the average bandwidth of decreasing loads must be calculated. The optimum (minimum) prime-fuel firing rate is the minimum stable prime-fuel rate plus the bandwidth of decreasing transients.

The prime-fuel base-loaded mode is best applied where the waste fuel is rate-limited for increasing demand only. Here the base load of the prime fuel is the minimum stable firing rate. Increasing transients are absorbed by the prime fuel, after which the waste fuel ramps up to return prime fuel to the minimum. Decreasing transients are absorbed by the waste fuel.

A control system that can be set to handle waste and prime fuel in all the above modes is shown in Fig 7. This system also includes a prime-fuel-only mode. This should always be included as a backup.

Other controlled variables

Fuel and air are the variables directly manipulated to control steam pressure, efficiency, fuel cost, and emissions. They are not the directly manipulated variables that control drum level, furnace pressure, or steam temperature. However, they can still have significant impact on these controlled variables. Typical problems encountered with these variables in a waste-fuel-fired boiler may have one or a combination of causes. The trouble is that units designed to burn multiple fuels (one or more of which may be waste fuels) necessarily compromise the design of furnace and heat-exchanger surfaces. An optimum design can be achieved only for a single homogenous fuel.

Drum-level control. The low heating value of many waste fuels dictates a need for a relatively large furnace volume and a high ratio of evaporator volume to drum volume for a given steam-generation rate. The result is that fireside upsets may have an overwhelmingly detrimental effect by upsetting the drum level. Unfortunately, fireside upsets are very often the rule because of the difficulties encountered in handling most waste fuels.

Similarly, different fuels have different heating values and may be introduced into different areas of the boiler. Normal sequencing and fuel changeover by the combustion-control system can create the same disturbances in drum level that are caused by firing upsets.

Steam-temperature control. Most large units built today are designed to deliver superheated steam and to burn a variety of fuels. Also, some are installed to operate at reduced pressure with provisions to raise steam pressure and temperature later. An example might be where cogeneration is planned.

All of this creates an almost impossible situation for optimizing size and surface configurations of superheaters. Different fuels have different heating values; they may be introduced to different parts of the furnace; they have different excess-air requirements; their ash and crud characteristics are different; and they have different corrosion and erosion effects. The list goes on and on to create a complex matrix of interacting variables. This means that control must be exerted over a much wider and more variable range.

Furnace-pressure control. This is much more difficult. Different fuels have different excess-air needs, and they may carry additional inert material and water vapor. Waste fuels may carry toxic, dirty, or noxious materials. These make negative furnace pressure control critical to prevent contamination of the boiler room. Nonlinear and feedforward control algorithms may be needed for satisfactory control of this critical variable.

The important thing to remember is that a problem defined is a problem solved. Evaluate the effect of different fuels on each of the controlled variables, and consider both operation objectives and process constraints in the control design.

Basic process limitations cannot be overcome by an overly complicated or misapplied control system. A properly designed control system doesn't limit operation of the boiler itself, but permits safe and stable operation up to the limits determined by the process.

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SESSION 18: BIOMASS GASIFICATION

For the last few years, a great deal of interest has arisen in producing gaseous fuels from biomass resources (i.e., biomass gasification). This session will be a summary of the various aspects of biomass gasification, including basic principles (chemistry), feedstock characteristics, gasifier types, applications, economics of use, and safety considerations. Most of this material has been drawn from a report titled "Biomass Gasification in Developing Countries" prepared for the World Bank in December 1982. Technical considerations for using producer gas in industrial applications are discussed in Appendix 18.A.

BASIC PRINCIPLES

The Four Phases of Biomass Gasification

Four distinct processes take place in a gasifier: drying of the fuel, pyrolysis, combustion, and reduction. Although there is considerable overlap, each process can be considered as occupying a separate zone in which fundamentally different chemical and thermal reactions take place. The fuel must pass through all of these zones to be completely gasified.

The combustion zone is generally situated near the base of the gasifier (see Exhibit 18.1). Also referred to as the oxidation or hearth zone, this area is where air is fed into the gasifier, allowing combustion of the fuel to take place as in an ordinary stove or furnace. Depending on the application, the necessary air draft may be created by the suction of an engine or by an appropriate arrangement of fans. The key feature is that the air supply is restricted **so that the burning does not spread to the entire fuel load.** If this situation occurred, the gasifier would simply become a stove, producing heat and incombustible gases.

The basic chemical reaction taking place in the combustion zone is the combination of oxygen in the air with carbon from the fuel to produce carbon dioxide, an incombustible gas. This reaction is exothermic (heat-releasing), and the temperature in the combustion

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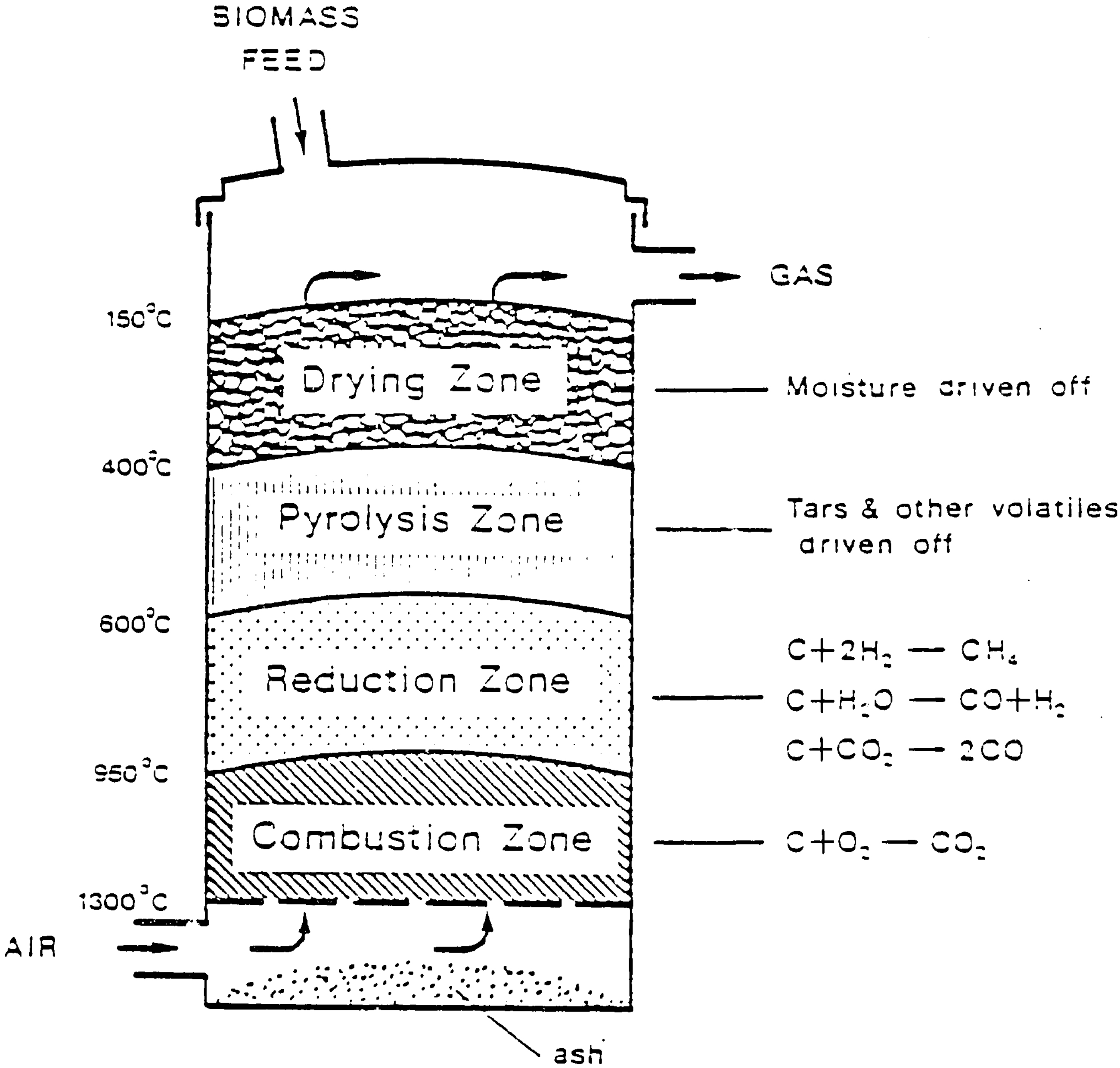
Exhibit 18.1

Schematic Diagram of the Reaction Zones in an Updraft Gasifier



zone consequently rises until the rate of heat loss balances the rate of heat gain from the combustion. Normally, the combustion zone reaches a temperature of between 900°C and 1,300°C, but in some gasifiers (particularly those of the crossdraft type using charcoal as a fuel), it can rise as high as 2,000°C. If any hydrogen is present in the combustion zone, it also reacts with oxygen. This reaction is also exothermic, and water vapor is the product.

From the combustion zone, the hot gases are next drawn into the reduction zone. The reduction zone is always adjacent to the combustion zone, but -- depending on the configuration of the gasifier -- it may be above, below, or beside it. No air is admitted here; hence, there is no free oxygen, and a different set of reactions takes place. These reactions are referred to as reducing reactions, and they play an essential role in gasification, as they convert some of the incombustible gases emerging from the combustion zone into combustible products.

The principal reaction in the reduction zone is that of carbon dioxide with hot carbon to produce carbon monoxide. This process is endothermic (i.e., it absorbs heat), and temperatures in excess of 900°C are required for it to take place. It is sometimes referred to as the "Boudouard" reaction, and the carbon monoxide produced is the major combustible component in the final mixture of gases drawn from the gasifier.

Another important reduction reaction is that between water vapor and carbon. This reaction, which is also endothermic, takes place only at temperatures above 900°C. Water is dissociated, yielding carbon monoxide and hydrogen as the products. It is usually called the "water gas" reaction; since both products of the reaction are combustible, it also increases the calorific value of the final gas.

In the course of these endothermic reactions, heat is absorbed from the gas stream. The temperature of the reduction zone, therefore, progressively drops as the gas is drawn further from the combustion zone. As it drops, a different set of reactions take over, one of which is the reaction of water vapor with carbon to produce hydrogen and carbon dioxide. This reaction predominates between 500°C and 600°C.

If excess water is present in the reduction zone, the so-called "water shift reaction" can also take place. In this reaction, carbon monoxide reacts with water to produce carbon dioxide and hydrogen. This exothermic reaction is generally regarded as unfavorable, since it reduces the calorific value of the final gas. **Excess moisture in the fuel, therefore, is to be avoided.**

If pure, dry charcoal is used (from which all the volatile components have been driven off in the manufacturing process), no hydrogen is available; hence, there is none in the final gas. Thus, the thermal value of the gas is typically about 20 percent lower than that from a wood gasifier. For this reason, it is common practice to add a small amount of water to the gasifier. Provided that the quantity is judged correctly, the resultant endothermic reactions lower the operating temperature of the gasifier and enrich the final gas, which also has the effect of reducing the thermal stress on the gasifier equipment.

Most of the hydrogen that is produced in the reduction zone remains free. However, a portion of it can combine with carbon to form small amounts of methane.

With the majority of biomass fuels, the quantity of water originally present is more than adequate. In fact, a considerable proportion normally passes through the gasifier without being dissociated and simply becomes a component in the final gas stream.

The principal chemical reactions occurring in the combustion and reduction zones are summarized below. Their precise sequence is complex, and their relative importance depends on fuel type, gasifier design, and operating conditions. The temperature profile within a gasifier is particularly important, as temperature affects both the position of chemical equilibria and the relative rates of different reactions.

1. $C + O_2 = CO_2$ (combustion reaction)	(+393,800 kJ/kg mole)
2. $C + CO_2 = 2\ CO$ (Boudouard reaction)	(-172,600 kJ/kg mole)
3. $C + H_2\ O = CO + H_2$ (water gas reaction)	(-131,400 kJ/kg mole)
4. $C + 2\ H_2\ O = CO_2 + 2\ H_2$	(-88,000 kJ/kg mole)
5. $CO + H_2O = CO_2 + H_2$ (water shift reaction)	(+41,200 kJ/kg mole)
6. $C + 2\ H_2 = CH_4$ (methane reaction)	(+75,000 kJ/kg mole)

The pyrolysis zone is generally above the combustion and reduction zones. No air is admitted to it, but it draws heat from the hotter regions that are adjacent to it. Once the temperature reaches about 400°C, a self-sustaining exothermic reaction takes place in which the natural structure of the wood or other organic material being used as fuel breaks down. This reaction is similar to that which occurs inside a kiln or closed retort in the manufacture of charcoal. Water vapor, methanol, acetic acid, and a considerable quantity of heavy hydrocarbon tars are evolved. In the case of wood, 50 percent or more of the original weight may be given off as tars and volatiles.

The solid material remaining after pyrolysis is carbon, in the form of charcoal. This material passes down through the gasifier and is consumed in the combustion and reduction zones. When charcoal is used as fuel, there is little or no evolution of pyrolysis products, since they have already been driven off in making the charcoal.

If the gas is to be used in an internal combustion engine, it is essential that it be free of tar. The volumes of tar produced when wood is used as fuel are so large that it would be virtually impossible for any gas cleaning system to eliminate them from the gas stream after it had left the gasifier. In addition, there would be a considerable loss of energy if the tars were simply rejected. Most wood-fueled gasifiers used for shaft power, therefore, are designed to draw the tar-laden gases through the combustion and reduction zones. Provided that the temperature in these zones is high enough, and the time taken to pass through is sufficiently long, the majority of the tars are broken down, thus yielding a reasonably clean final gas.

The drying zone is generally at the top of the gasifier, above the pyrolysis zone. Here the temperature is not high enough to cause chemical breakdown, but any moisture in the fuel is driven off in the form water vapor.

GAS CHARACTERISTICS

Producer gas has a relatively low thermal value, generally only 10 to 15 percent that of natural gas. The diluting effect of nitrogen in the combustion air is the principal reason for this low thermal value. The air fed into a gasifier contains approximately 78 percent nitrogen. Since nitrogen is inert, it passes through the gasifier without entering into any major chemical reactions. The final gas mixture, therefore, usually contains at least 50 percent nitrogen.

Using pure oxygen, instead of air, to feed the combustion leads to a much higher thermal value in the final gas. However, the added expense and complexity of the process preclude it from most small-scale uses and from any widespread application in the rural areas of developing countries.

Typical data for the final composition of producer gas are shown in the table below for both wood and charcoal gasifiers. These values are drawn from a variety of sources and are based on the composition of a dry gas. While figures of this kind provide a useful indication of the chemical reactions that have taken place in the gasifier, they do not tell the whole story. The quantity of water vapor present is also important, as it has a major effect on the net heating value of the gas. The more water vapor the gas contains, the less useful heat can be obtained from the gas; in the extreme case, the gas may be incombustible. Practical difficulties can also arise from water condensation after the gasifier has been shut down, which can dampen the fuel left in the gasifier and make it difficult to reignite.

COMPOSITION OF GAS FROM WOOD AND CHARCOAL GASIFIERS

Gas	Wood gas, % (dry basis)	Charcoal gas, % (dry basis)
Nitrogen	50-54	60-63
Carbon monoxide	20-22	23-33
Carbon dioxide	9-11	3-7
Hydrogen	12-15	4-14
Methane	2-3	-
Heat content	5,500 kJ/m^3	4,100 kJ/m^3

Fluctuations in the load on a gasifier can also cause a variety of problems. To vary the output of a gasifier, the supply of air must be adjusted. As a result, the combustion zone expands or contracts, which in turn affects both the size and position of the other reaction zones in the gasifier. Small variations in load can usually be accommodated quite easily, and the gas composition will not change radically. Larger changes are more problematic, since the balance of the chemical reactions -- and, along with it, the final product mix -- will change.

At very low loads, tar production becomes a problem in designs that rely on drawing pyrolysis products through the combustion zone to crack them. Since both the size and the temperature of the combustion zone are reduced at low loads, the cracking may not be fully completed. In some cases, cold channels can form, allowing pyrolysis gases to percolate through the combustion zone unchanged, thus producing a very dirty gas.

The ability of gasifiers to respond to load changes varies between designs. In all cases, however, steady-load operation is preferable, as it allows the design and construction of a gasifier to be optimized around a particular set of operating conditions.

FEEDSTOCK CHARACTERISTICS

Almost any carbonaceous or biomass fuel can be gasified under experimental or laboratory conditions. However, the suitability of a particular fuel* for a given gasifier design can be established only by prolonged practical use. Without this type of experience, there can be no guarantee that the fuel will perform satisfactorily under actual operating conditions.

Wood, charcoal, various types of coal, and -- to a much lesser extent -- peat have been used extensively. A vast body of experience has been built up around them. Ensuring satisfactory standards of size, cleanliness, and moisture content was a recurrent problem. In countries where gasifiers have been widely used, very detailed government specifications have usually been drawn up to protect gasifier users from careless or unscrupulous suppliers.

Charcoal has been amply proved as the most reliable and trouble-free fuel. Nevertheless, care is needed in its preparation and storage. Most charcoal contains some of the original tarry substances from the charcoal-making process. In small quantities, these substances are unlikely to cause any problems and may even be beneficial in that they make kindling easier when the gasifier is being started. Charcoal made by the traditional

*"Fuel" and "feedstock" are considered here as synonymous.

pit method, however, may be little more than lightly-charred wood and may contain up to 40 percent volatile material. Such charcoal would be heavily tar-producing and quite unsuitable for most charcoal gasifiers. Quality control in the manufacture and selection of charcoal for gasifiers, therefore, is essential.

A major disadvantage of using charcoal is that, in energy terms, it is generally a very inefficient way of using forest resources. Driving off the volatiles from wood to produce charcoal wastes a substantial amount of energy. Under good manufacturing conditions (for example, a steel kiln or retort), around 50 percent of the original energy in the wood is likely to be lost. When made by the pit method, the losses may be as high as 80 percent. One solution is to salvage the tars and pyrolysis gases and use them for other purposes. However, to do so greatly complicates the charcoal-making process and has not yet proven to be practical or economic in most developing countries.

Wood is also a thoroughly well-tried fuel. The World War II experience exposed most of its problems and advantages. The size of the wood feed is one factor that can be important, depending on the design of the gasifier. The wartime Swedish gasifiers, for example, could use billets of up to 90 mm in diameter and 75 mm long. In contrast, modern Swedish designs require small wood chips with a maximum dimension of just a few millimeters. A uniform size distribution generally is preferable. Large amounts of very small particles can cause difficulties in drawing air through the gasifier, and may also result in bridging of the fuel.

Chipping and screening of wood, if required, is a relatively straightforward process, given the necessary mechanical equipment. It is a standard feature of the forest-product and wood-pulp industries. In developing country villages, however, such equipment will often be unavailable or too expensive, and producing small wood chips will be out of the question if hand-chipping is the only method available. The choice of a gasifier in such cases will be restricted to units that can accept reasonably large pieces of wood.

Sawdust has the advantage of being a readily available waste product in areas near forest industries. However, major problems have been encountered in gasifying it effectively. A handful of direct-heat gasifiers have been developed that can use sawdust, but in most systems it is still an experimental fuel.

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Other biomass fuels may also be used in gasifiers. A list of materials on which limited tests have been performed is presented in Exhibit 18.2. However, much more experience will be required with most of these fuels before definite pronouncements can be made regarding their practical suitability.

Of these candidate fuels, coconut shells are among the most promising. They are similar to wood in many of their properties and are already used as a source of high-quality charcoal in a number of countries. Tests on coconut shells in gasifiers have been carried out in the Philippines without any major problems. All that appears to be necessary is a period of extended operating experience to confirm this view and establish a set of specifications for the maximum and minimum size of particles, the maximum moisture content, and any other relevant charcteristics affecting their use as fuel.

Much the same can be said for maize cobs. Based on the experimental results that now exist, they too appear quite suitable as gasifier fuels. Again, however, the extended operating experience necessary for full confidence in their use is lacking.

As far as most other biomass materials are concerned, the amount of practical operating experience is so small that any discussion of their suitability must remain at a largely theoretical level. Nevertheless, some general observations can be made about the types of materials that are most likely to be suitable as gasifier fuels.

One of the major factors is the amount of ash contained by a fuel and its chemical composition. Ash is the mineral material that remains after complete combustion. It usually derives from the fuel itself, but it may also occur as a result of the way the fuel is collected, processed, and stored. For example, clay and dust may be unavoidable in the collection of some kinds of agricultural residues and waste products.

Ash can cause a variety of difficulties. If it is present in large quantities, it may accumulate in the gasifier and impede the chemical reactions or clog the equipment. Problems tend to be particularly severe if the ash has a low fusion point. When the temperature in the combustion zone exceeds the fusion temperature, the ash melts. As soon as it leaves the combustion zone and the temperature drops, the molten ash resolidifies. Slag is the term usually used to describe the deposits of solidified ash

Exhibit 18.2

Ash Content and Gasification Properties
of Selected Biomass Fuels

Material	Ash content (% of dry weight)	Remarks
Alfalfa straw	6.0	No slagging
Almond shells	4.8	No slagging
Barley straw mixture	10.3	Severe slagging
Bean straw	10.6	Severe slagging
Coconut husks	6.0	Some slagging
Coconut shells	0.8	No slagging
Cotton gin trash	17.6	Severe slagging
Cotton gin stalks	17.2	Severe slagging
Maize cobs	1.5	No slagging
Olive pits	3.2	No slagging
Peach pits	0.9	No slagging
Pelleted rice hulls	14.9	Severe slagging
Prune pits	0.5	No slagging
Safflower straw	6.0	Minor slagging
Sugarcane bagasse	1.5-11.3	Slagging
Walnut shells	1.1	No slagging
Wood	0.2-1.0	No slagging

that can form on the internal surfaces of a gasifier. A serious build-up of slag will distort the geometry of the combustion zone, making control difficult; it may also block the grate and interfere with the air and gas flow.

The ash content of a feedstock and its melting characteristics, therefore, can be crucial determinants of the suitability of a particular material as a gasifier fuel. Wood and charcoal generally cause no serious problems with slagging or clinkers because their ash content is usually low, in most temperate species less than 2 percent. The ash content of maize cobs and coconut shells is between 0.75 percent and 1.5 percent, but rice husks and cotton trash can have ash contents of as high as 20 percent.

Rice husks are a particularly attractive subject for research workers. Large quantities are available, and disposal of waste husks is a considerable problem at many rice mills. However, they are a notoriously difficult fuel to gasify.

Although many researchers are extremely pessimistic about the prospects for rice husk gasification, encouraging results have been reported from work in the Philippines. The use of compressed or pelletized husks is said to be promising. Progress is also being made in the Peoples Republic of China. Delegates to an FAO conference held at Suzhon, near Shanghai, in June 1982 were shown a 150-kW rice husk gasifier that operates 24 hours a day, with 1 day per week set aside for cleaning.

Careful analysis and testing are essential before any fuel can be declared suitable, even in principle, for practical gasifier use. The indications are that the minimum requirements for a fuel to be usable with present technology are that it should **have an ash content not greater than 5 to 6 percent, a total silica content of not more than 2 percent, and an ash fusion temperature above 1,150°C.** Outside these limits, problems can be anticipated. At the time of use, it is also usually necessary for the moisture content to be below 20 percent; for some gasifier designs, the maximum is 10 percent.

In addition to their chemical composition, the suitability of fuels is also determined by their physical characteristics. The permeability of the bed of fuel is extremely important, for example, in determining the pressure drop that occurs across the gasifier; it also affects the manner in which the chemical reactions in the combustion and reduction zones take place. Sawdust tends to agglomerate, for instance, and develops channels through which pyrolysis gases can pass without being broken down. With some types of straw, coconut husks, and other low-density materials, bridging may occur and slow the rate of movement of the fuel into the combustion zone. Means of stirring the fuel bunker to break up the bridging and clogging may be necessary in such cases. Pelletization of fuels can also be a successful way of dealing with problem materials, although experience with gasifying biomass pellets is still minimal.

Apart from general considerations regarding fuel suitability, individual gasifier designs also have their own particular limits; fuels usable in one type will not necessarily be suitable for another. A gasifier designed to use wood blocks will not always be able to work satisfactorily on wood chips, nor is it possible to use wood and charcoal completely interchangeably. Many of the rapid-starting, high-performance gasifiers developed during World War II relied on clean, good-quality charcoal and became unusable if run on any other fuels. The price of high performance in a gasifier is usually a very low tolerance to variations in the quality of the fuel.

GASIFIER TYPES

The cessation of interest in gasifiers at the end of World War II has meant that the technology has remained virtually static for the last 35 years. There have been improvements in materials -- better high-temperature steel alloys are available, for example -- and science is equipped with much more powerful analytical tools, but basic gasifier designs have not changed, nor have there been any major advances in the technical or scientific understanding of the fundamental principles on which gasifiers work. The textbooks are still those of the 1930s and 1940s.

Gasifier designers are faced with a series of conflicting demands. Ideally, a gasifier should be able to produce a clean, high-quality gas from a wide range of fuels; it should be capable of working efficiently without constant attention; it should be able to respond rapidly to changes in load; and it should be cheap and durable. In practice, many of these requirements are mutually contradictory. Individual designs must be a compromise based on the necessities of their particular end use.

Updraft Gasifiers

The simplest gasifier is the updraft or countercurrent type. The air intake is at the bottom, and the gas is drawn off at the top. Fuel is fed in at the top and moves downward as it is consumed. The term countercurrent refers to the fact that the air and gas flows are in opposite directions. An updraft gasifier was shown schematically in Exhibit 18.1.

Updraft gasifiers tend to have a high thermal efficiency because the hot gases from the combustion zone pass upward through the incoming fuel load and preheat it. Double-wall arrangements are also sometimes used to enable heat exchange to occur between the outgoing gas and the incoming combustion air. The exit temperatures for the gas are usually between 100°C and 200°C.

Simplicity is the major feature of the updraft gasifier. Its main disadvantage is that unless a tar-free fuel is used, the gas tends to be extremely dirty. None of the tars and other pyrolysis products are cracked in the combustion zone; instead, they are drawn into the upward flow of the gases. They leave the gasifier and will condense out of the gas stream if its temperature is allowed to drop.

Some updraft gasifiers are deliberately designed to operate at high temperatures (1,300°C and above) to melt the ash so that it falls through the grate. This type is called a slagging gasifier. Refractory materials are usually used to line the combustion zone and sometimes the entire interior of the gasifier. As well as protecting the metal structure of the gasifier, this lining acts as an insulating layer and cuts down heat losses.

Updraft gasifiers can be built to handle a wide variety of fuels. A number of manufacturers, for example, have reported considerable progress in the design of large updraft systems for the gasification of municipal wastes. The fact that the gas produced in an updraft gasifier normally contains a considerable quantity of tar almost totally precludes its use with internal combustion engines. When the gas is used for direct-heat purposes and is simply burned, tar is not such a problem. The modern use of updraft gasifiers, therefore, is almost entirely restricted to direct-heat applications.

Downdraft Gasifiers

By far the most common gasifier is the downdraft or co-current type. Most of the mobile gasifiers used in World War II were of this type, as are the majority of those currently being developed for shaft-power applications. A downdraft gasifier is shown schematically in Exhibit 18.3. The combustion zone is part-way up the unit, with the pyrolysis zone above it and the reduction zone below. Fuel is fed in at the top. The flow of air is downward through the combustion and reduction zones, and the term co-current refers to the fact that the movement of air is in the same direction as that of the fuel.

The essential characteristic of the downdraft gasifier is that it is designed so that the tars given off in the pyrolysis zone are drawn through the combustion zone, where — provided that the gasifier is working properly — they will be broken down or burned. When this happens, the energy they contain is usefully released, and the mixture of gases in the exit stream is relatively clean. The arrangement of the combustion, or hearth, zone is thus a critical element in a downdraft gasifier. If low-temperature spots are allowed to form there, the tar-laden gases will percolate through them without their tars being broken down, thus defeating the purpose of the design.

In most downdraft gasifiers, the internal diameter is reduced in the combustion zone to create what is referred to as a throat. The throat is frequently made of replaceable ceramic material. Air inlet nozzles are commonly set in a ring around the throat to distribute air as uniformly as possible.

Temperature considerations put an upper limit on the size of the downdraft gasifiers; very few are capable of running engines much in excess of 100 kW.

There are many variations on the basic downdraft design. Gasifier technology is still far more an art than a science, and experience has led to a large number of empirical modifications that improve efficiency and assist in running, cleaning, and maintenance. Double-wall arrangements similar to those used in updraft gasifiers are common as a method of achieving some heat exchange and increasing the thermal efficiency. Many types also incorporate a means of draining the condensed water and tars from the upper internal walls of the gasifier. The combustion zone is frequently lined with a

Exhibit 18.3

Schematic Diagram of a Down-Draft Gasifier

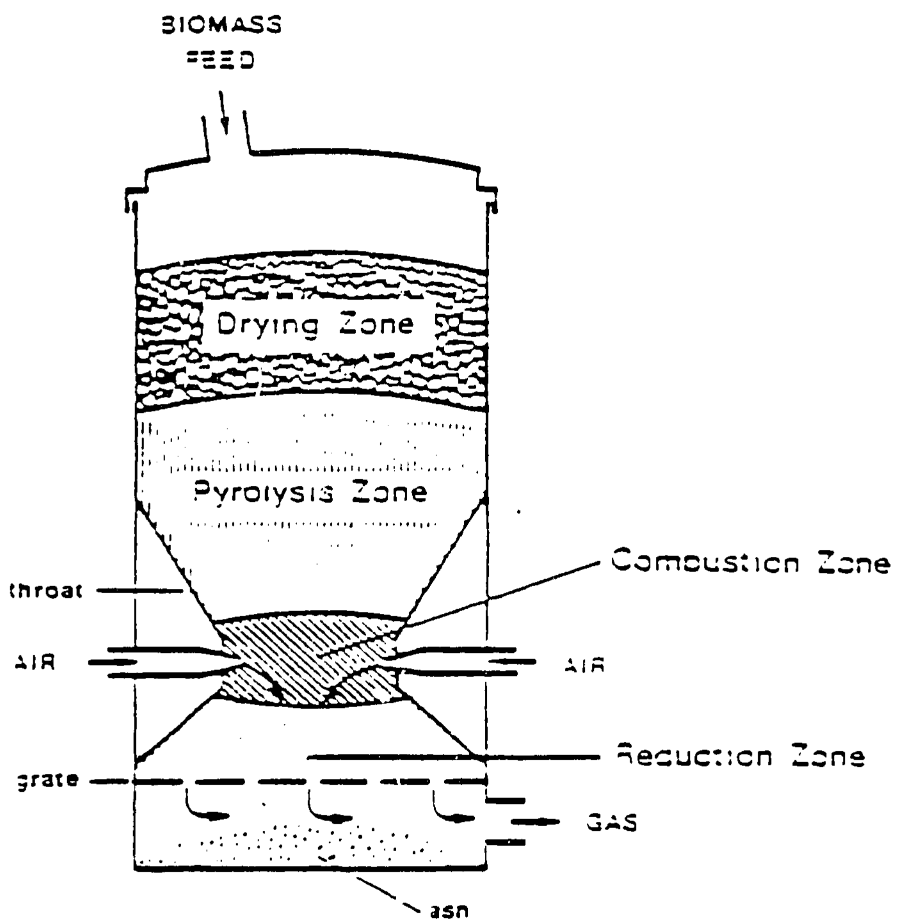
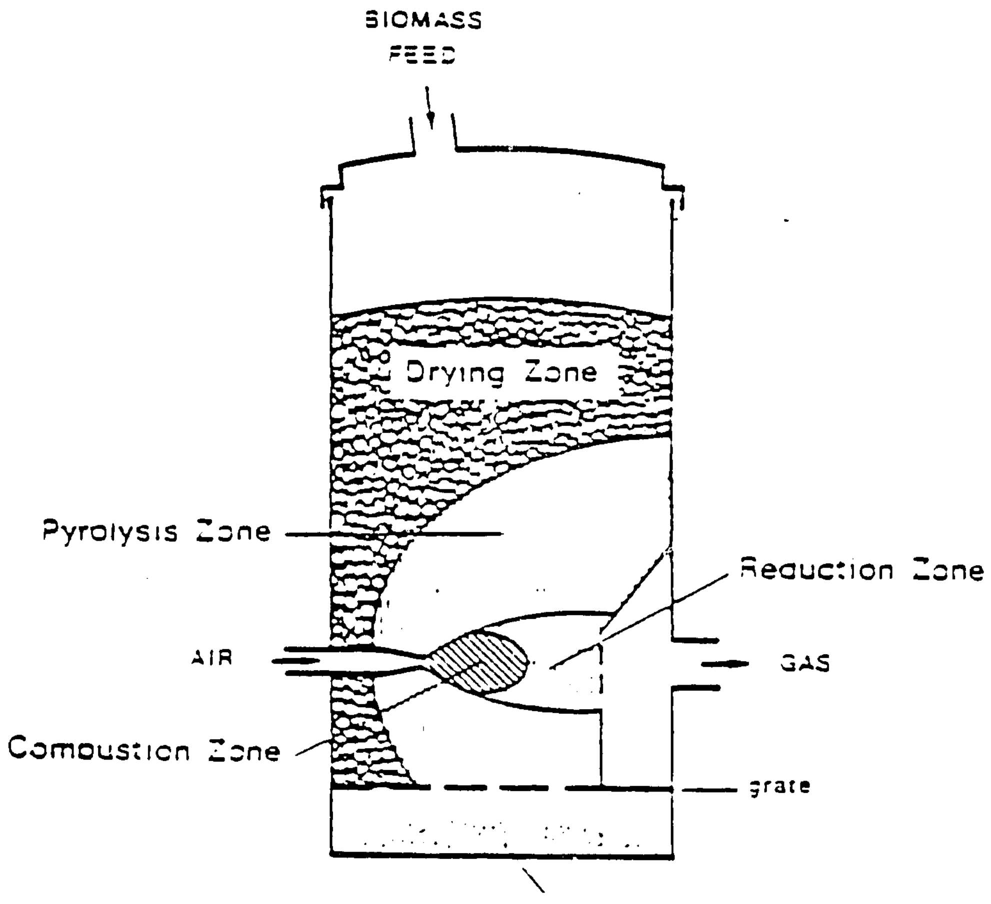


Exhibit 18.4

Schematic Diagram of a Cross-Draft Gasifier



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replaceable refractory lining, but in other cases a specially heat-resistant steel may be used.

Because the gas leaves directly from the reduction zone, it tends to contain significant quantities of ash particles and soot, in contrast to the updraft gasifier where these particulates are mostly filtered out as the gas passes upwards through the unburned fuel. The exit temperature also tends to be somewhat higher with downdraft designs because the heat exchange in the fuel drying zone does not take place.

Downdraft gasifiers have the advantage that they produce a relatively tar-free gas when they are working properly. However, the difficulties involved in doing so must not be underestimated. The design of the hearth zone and the control of the air flow are critical factors. Downdraft gasifiers are particularly vulnerable to the problems caused by high ash-content fuels and those with a tendency to slag. They are also sensitive to changes in moisture content.

Crossdraft Gasifiers

In the crossdraft gasifier, air is introduced on one side of the gasification chamber and the gas outlet is on the opposite site. Normally, an inlet nozzle is used to bring the air into the center of the combustion zone, as shown in Exhibit 18.4.

The velocity of air as it enters the combustion zone is considerably higher in crossdraft gasifiers than in other designs, creating an extremely hot combustion zone from which the liberation of gas is very rapid. Both the combustion and reduction zones are concentrated into a small volume in the center of the gasifier, which means that refractory materials are not normally needed for lining the combustion zone walls.

The main advantages of the crossdraft gasifier are its rapid response to changes in load, its simplicity of construction, and its reduced weight. It is best suited for running engines with an output of up to 50 kW. However, it is very sensitive to changes in fuel composition and moisture content. For practical purposes, specially selected clean charcoal is almost always required.

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Crossdraft gasifiers were quite popular during World War II, particularly for running vehicles. One of the best known makes was the Gohin-Poulenc, of which 8,000 were in use in France in 1939. It has now re-emerged on a commercial basis in Brazil. A small crossdraft unit has also been developed in the United Kingdom, relying on charcoal dust as a fuel and aimed specifically at uses in the Third World.

Fluidized-Bed Gasifiers

The problems of gasifying high-ash fuels, particularly when the ash has a low melting point, have already been noted. These fuels are extremely difficult to deal with in downdraft gasifiers. An approach that is being investigated in a number of places is the use of the fluidized-bed principle.

In a fluidized bed, air is blown upward through an alumina sand bed at sufficient velocity to keep it in a state of suspension, thus behaving like a fluid. The bed is heated by an external fuel source. When it reaches a sufficiently high temperature, the fuel -- which must be in the form of small particles -- is introduced by a mechanical feed.

The major advantage of the fluidized-bed gasifier is that its temperature can be controlled easily by varying the rate of air and fuel inputs. Because of its low operating temperature, which at 800°C-900°C is below the fusion temperature of most types of ash, slag and clinker formation can be avoided, thus opening the possibility of gasifying a range of fuels that cannot be used satisfactorily in present gasifier designs.

However, there are a number of problems with fluidized-bed gasifiers. They work at a slightly higher pressure than atmospheric pressure; hence, their construction must be of a very high standard to avoid gas leaks, and their fuel-feed systems must have a pressure lock. They are extremely slow to bring into operation, and require several hours to heat up from cold before they can begin to produce gas. On the other hand, their heat retention is high, and they can be closed down overnight and restarted rapidly the next morning.

Another important limitation is their poor load-following characteristics. As the fuel is fed into the bed, it is gasified immediately. Hence, there is no buffer stock of unburned fuel inside the gasifier, as in the case of other designs. The gas output is thus directly related to the speed at which fuel is added, and changes of load in on the gasifier must be matched by changes in the fuel-feed rate, making fluidized-bed gasifiers inherently slower in their responses to load changes than are other types of gasifiers.

The gas from a fluidized-bed gasifier tends to have a rather high tar content. Using wood, one currently operating test installation yields a gas with a tar content of 250-500 mg/m^3, which puts heavy demands on the cleaning equipment. The gas also contains a large amount of unburned carbon particles, as well as all of the ash originally contained in the fuel. These materials must also be removed by the cleaning system.

Although the limitations are clearly evident, and some of the practical and economic problems to be resolved are severe, many researchers feel that there is a large future for fluidized-bed gasifiers. This view stems from the ability of these gasifiers to use fuels such as rice husks and sawdust, which are widely available but are difficult to gasify with presently available technology. The development of fluidized-bed techniques for gasifying biomass fuels is still at a relatively early stage.

Other Gasifier Types

A variety of other gasifier types has been developed over the years. The 19th century saw double-stage gasifiers in which different fuels were used in each, the first taking a tarry fuel and producing a gas that was fed into a second unit that used clean coke. Double-fire gasifiers have been produced in which there are two combustion zones in the same cylinder, and various methods have been devised for extracting the pyrolysis gases and reinjecting them into the combustion zone.

One contemporary French gasifier manufacturer, Moteurs Duvant, has developed a dual-chamber gasifier system for use in engine applications of 200 kW and higher. It is essentially a downdraft gasifier, but the pyrolysis gases are drawn off from the pyrolysis zone, burned in a separate chamber, and reinjected into the combustion zone, thus ensuring a complete breakdown of the tars and avoiding the problems caused by percolation of pyrolysis products through cold spots in the combustion zone and the resultant contamination of the output gas. However, the complexity of this arrangement makes it completely uneconomic for smaller gasifier sizes. These dual-chamber units are large and costly pieces of equipment that must be individually designed and tailored to their location, application, and available fuel.

APPLICATIONS

Biomass gasifiers can be used for a variety of fixed and mobile applications. In the following paragraphs, four types of applications will be presented: industrial shaft power, rural electrification, irrigation, and direct heat.

Industrial Shaft Power

The main use for shaft-power gasifiers in industry is in rural areas where grid electricity is either expensive or unavailable, and diesel or gasoline power are the main alternatives. Stationary gasifiers are rarely attractive in towns, because even when biomass fuels are available at no cost, grid electricity is usually a cheaper source of power. Electricity from the grid also has the obvious advantages of versatility and convenience.

For large-scale shaft-power requirements, steam power must also be considered as an alternative. Although less common than they once were, steam engines are still used in quite a few developing countries. They are much more flexible than gasifiers in the types of fuel they can accept, and they pose fewer technical problems. Steam power has a particular advantage in industries where demands for heat and shaft power exist together. Process steam can be generated in a conventional solid-fuel boiler, using biomass fuels or coal, and part of it can be run through a steam turbine to produce electricity. With well-run equipment, this is both efficient and cost-effective. Using gasifiers in such cases would generally be more complicated and would not necessarily save money.

Examples of industries where steam systems of this kind are currently used include the sugar industry and large-scale wood processing, where heat is required for kiln drying and other purposes. The principal disadvantages of steam systems are their high initial costs and the fact that there are very few steam engines currently available with an output of less than about 200 kW. Several research groups are now looking into small-scale steam systems, however, and the results of this work should be monitored to keep abreast of future developments.

Sawmills present good opportunities for using gasifiers in isolated areas, as a biomass residue is produced as part of the process. The most obvious sawmill applications for gasifiers, therefore, are in cases where grid electricity is unavailable, diesel oil is expensive or scarce, and residues have a low economic value. These conditions are most likely to coincide where sawmills are located in forest areas with a low population density. For flexibility and convenience, it will generally make sense to run gasifiers to generate electricity and to use the generated electricity to run machinery, rather than employ direct-drive systems.

Of the residues produced in sawmills, offcuts and edgings are technically the best suited for use in shaft-power gasifiers. They simply need to be chipped or cut into small blocks and dried to the appropriate moisture content. However, where there are competing demands, these residues also tend to be the most valuable. In such cases, sawdust would be a more economically attractive feedstock. Designs for sawdust gasifiers have not yet advanced to a commercial stage, however, and further developmental work will be required before they can be considered for shaft-power applications.

Rural Electrification

Diesel-powered electricity generators are widely used, particularly in remote rural locations where grid electricity is either unavailable or unreliable. Although the theoretical potential for using gasifiers to run generating sets is quite large, they will be feasible only in cases where the electricity demand is relatively steady and an adequate supply of fuel can be provided. The opportunities for using gasifiers in this role are probably greatest in forest areas, where a local demand exists for electricity for village use or small industries.

In areas where wood is scarce, tree plantations will be essential if gasifiers are not to aggravate existing pressures on wood resources. The size of plantation needed to supply a gasifier-powered generator can readily be estimated. Using a dual-fuel diesel engine, approximately 1.75 kg of air-dry wood would be required to produce 1 kWh of electricity, assuming a generator efficiency of 80 percent. A tonne of wood would give roughly 570 kWh.

With an annual plantation productivity of 5, 10, and 20 air-dry tonnes per hectare and an operating period of 2,000 hours per year, the plantation area necessary to supply generators of different sizes is shown in Exhibit 18.5.

To put these estimates in context, a village of 400 people with a fairly low per-capita electricity demand of, say, 200 kWh/year would require 140 tonnes of wood per year to run a gasifier-powered generator. At an annual wood yield of 10 tonnes per hectare (which might be expected in a region with moderate rainfall), a 14-hectare plantation would be needed, which is equivalent to 0.035 hectares for each person in the village.

Irrigation

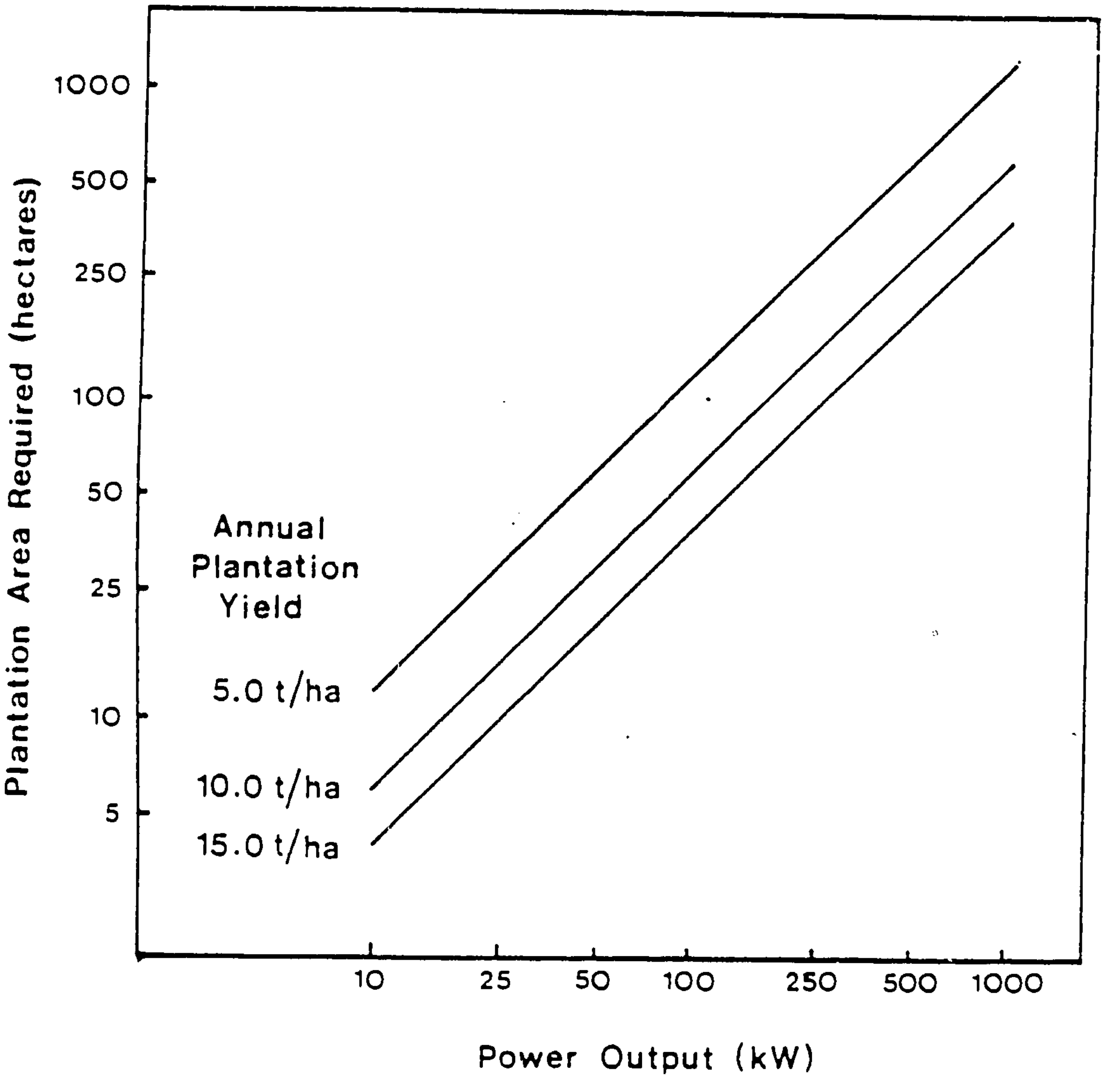
One of the most widespread demands for shaft power is for irrigation pumps. Diesel pumps of various sizes are already in use in many locations. Where diesel fuel is expensive, and where interruptions in supplies are common, there are strong arguments for seeking alternative fuel sources such as gasifiers.

The shaft power required to irrigate a hectare of land depends on the pumping depth and the quantity of water applied. A typical range is from 0.3 to 0.7 kW per hectare. Irrigation requirements are generally seasonal, however, so systems will often be needed for only part of the year. An annual operating period of between 600 and 1,200 hours is probably a reasonable average in most cases. Where the level of use is toward the low end of this range, gasifier-powered irrigation will often be ruled out for purely economic reasons.

The question of fuel supply is also important. Assuming a shaft power demand of 0.5 kW/ha and an irrigation period of 800 hours per year, the total annual shaft power requirements would be 400 kWh. A series of simple calculations can again provide useful indicators of what is involved in supplying the necessary fuel for a gasifier.

Exhibit 18.5

Plantation Area Requirements for Gasifier-Powered Electricity Generation Systems



A reasonably efficient gasifier system with a dual-fuel diesel engine uses approximately 1.4 kg of wood per kWh of shaft power generated, which means that wood consumption will be roughly 560 kg per year for every hectare irrigated. Assuming that wood is specifically grown for the purpose, the area required would range from 0.035 to 0.11 hectares for plantations yielding between 5 and 20 tonnes of air-dry wood per hectare annually. In other words, an area equivalent to between 4 and 11 percent of the irrigated land area would have to be planted with trees to supply enough wood to run the pump.

Direct Heat

The primary application for direct-heat gasifiers is in industries where fuel oil is currently being used to generate process heat or to run furnaces and kilns. Since fuel oil is used extensively by the industrial sector, a large number of uses are possible (see Session 6). At the individual plant level, of course, there will be many instances where retrofitting with gasifiers will not be feasible. Equipment will not always be compatible, given the limited range of gasifier systems now available, and in special applications (such as where rapid load fluctuations occur), gasifiers may not be able to match the performance of conventional oil-burning systems. In general, however, there will be no shortage of applications that are technically suitable for retrofitting with direct-heat gasifiers. The main limitation in most cases will be the problem of providing an adequate biomass supply.

As a rough guide, a 10-GJ/hr gasifier system operating at 60 percent capacitv for 4,000 hours per year would use approximately 4,000 tonnes of air-dry wood each year. Given an annual yield of 10 tonnes/hectare, a unit of this size would require 400 hectares of plantation to provide the necessary fuel.

Since there is considerable flexibility in the price that can be paid for wood, having to establish a special plantation does not necessarily rule out the use of direct-heat gasifiers. However, it does increase the managerial and organizational requirements, as well as introducing a 4- to 6-year delay before trees can be harvested.

In summary, the economic and technical problems of using direct-heat gasifiers appear to be relatively minor. As experience is gained and designs improve, the range of potential uses will widen further. However, fuel availability constraints will remain, and in the long term will probably be the principal limitation on the spread of the technology.

ECONOMICS OF USE

The economic case for gasification rests on the savings that can be achieved by using cheap biomass instead of high-cost petroleum fuels. The capital cost of gasifier equipment, as well as the increased operation and maintenance expenses, must be offset by these savings.

In the analysis presented here, shaft-power and direct-heat systems are considered separately. In each case, baseline calculations are performed using typical values for all the major cost items likely to be encountered in a gasifier installation. The major assumptions are then varied systematically to test their effect on the economic feasibility.

Economics of Shaft-Power Systems

The conversion of stationary diesel engines to run on producer gas is one of the most important potential uses for shaft-power gasifiers. The example chosen for the economic analysis is a comparison between a conventional 50-kW diesel unit and a gasifier-powered dual-fuel diesel engine with the same output. The gasifier fuel was assumed to be wood, but an additional calculation was carried out to assess the effects of using charcoal. An assessment was also made of the cost of running a gasoline engine on producer gas.

Estimates of all the major cost components were included in the calculations, which permitted a figure for the total cost of shaft power from both systems to be derived. The important parameters were then varied to observe the sensitivity of the final result to changes in the original assumptions.

As might be predicted, with a variation of a factor of 10 between the capital cost of a cheap, locally-manufactured unit and a sophisticated imported model, the initial cost of the gasifier proved to be the single most important factor determining the final cost of power. If gasifiers are cheap, cost savings are possible under a wide range of conditions. If they are expensive, the economics are much less favorable, and the circumstances where they can be economically justified are fairly rare.

Assumptions and Baseline Cases

The main parameters used in the economic analysis are listed in Exhibit 18.6. The key assumptions, and the reasons for their choice, are discussed in more detail below.

Capital Cost of Equipment

Variations in the reported cost of gasification equipment are very wide. The systems currently being produced in Europe and the United States cost between $400/kW and $1,000/kW for the gasifier and gas cleaning system alone. At the other end of the spectrum, systems now commercially available in the Philippines and Brazil cost as little as $40/kW to $80/kW. To reflect this large variation, three separate assumptions were used for the baseline calculations:

Case A:	low-cost gasifier	$75/kW
Case B:	medium-cost gasifier	$200/kW
Case C:	high-cost gasifier	$800/kW.

These costs include the cleaning equipment and installation costs but not the associated diesel engine. Engines were assumed to cost $300/kW in both the diesel and the gasifier systems.

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Exhibit 18.6

Assumptions Used in Economic Analysis of Shaft-Power Systems

Variable	Value used for baseline cases	Range of values used in sensitivity analysis
Power output	50 kW	--
Interest rate	10%	5%-30%
Oil price inflation	0%	0%-9%
System lifetime	6 years	3-9 years
Annual operating period	2,000 hours	500-8,000 hours
Diesel cost	$0.40/liter	$0.30-$0.60/liter
Wood cost	$20/air-dry tonne	$0-$40/tonne
Charcoal cost	--	$40-$150/tonne
Diesel system		
Diesel engine cost	$300/kW	$150-$600/kW
Annual maintenance cost	5% of capital cost	--
Lubricant cost	5% of diesel cost	--
Diesel consumption	0.4 liters/kWh	0.3-0.4 liters/kWh
Gasifier system		
Cost of gasifier	$75; $200; $800/kW	--
Annual maintenance cost	10% of capital cost	5%-20%
Lubricant cost	2 x lube cost for diesel system	1-4 x lube cost for diesel system
Additional labor cost	$1,000/year	$500-$2,000/year
Diesel substitution	80%	50%-100%
Engine derating	0%	0%-30%
Diesel consumption	0.08 liters/kWh	0.06-0.08 liters/kWh
Wood consumption	1.4 kg/kWh	1.0-1.8 kg/kWh
Charcoal consumption	--	0.7 kg/kWh

Annual Operating Period and System Lifetime

Systems were assumed to run at full power output for 2,000 hours per year, with replacement after 6 years. This rate of output is equivalent to 8 hours of operation per weekday and a total working life of 12,000 hours. It is the kind of operating schedule that might be expected from a unit supplying motive power or electricity in a manufacturing or year-round processing industry, and would also apply in the case of a heavily-used commercial road vehicle.

For the sensitivity analysis, a minimum operating period of 500 hours was taken. This would occur in highly seasonal activities, such as crop processing, and in some irrigation applications. The upper limit of 8,000 hours would rarely be reached in practice, as it represents virtually full-time operation, day and night, throughout the year.

Fuel Consumption

In the baseline case, fuel consumption in the diesel system was taken at 0.4 liters/kWh, which corresponds to an engine efficiency of 25 percent. While efficiencies of up to 35 percent are possible with steady running and a well-maintained diesel engine, such high levels are rarely achieved in Third World applications. The effect of engine efficiencies of up to 33 percent is considered in the sensitivity analysis.

When operating on producer gas, an 80-percent replacement of diesel was assumed, thus cutting diesel consumption to 0.8 liters/kWh. This amount is close to the maximum diesel replacement practical for dual-fuel engines. The sensitivity analysis considers a lower bound of 50 percent and a hypothetical upper limit of 100 percent.

A moderately high wood consumption of 1.4 kg/kWh (air-dry wood) by the gasifier was assumed for the baseline case, which corresponds to an efficiency of 58 percent for the gasifier unit alone. The range of gasifier efficiencies considered in the sensitivity analysis was 43 to 78 percent.

Engine Derating

Although operation with gasifiers almost always leads to a certain degree of engine derating, this was not taken into account in the baseline case because in many applications, engines are run at less than their maximum output, so the effect of engine derating is unimportant. The influence of an engine derating of up to 30 percent, in cases where it is necessary to use a larger diesel engine to compensate for the loss of power, is discussed as part of the sensitivity analysis.

Maintenance, Lubrication, and Additional Labor

Annual maintenance costs were assumed to be 10 percent of the capital cost of the gasifier system, and 5 percent of the conventional diesel system. The upper figure of 20 percent in the sensitivity analysis represents a high level of dependence on imported spare parts and technical assistance; at 5 percent, the lower figure represents a greater indigenous repair and maintenance capability.

Lubrication costs were assumed to be 5 percent of the total fuel costs in the diesel system. Double this amount was assumed for the gasifier to allow for more frequent oil changes and replacement of filter materials in the gas-cleaning equipment.

A figure of $1,000 was allowed to cover the extra labor required for fuel loading and general running of a gasifier. This reflects the cost of hiring one full-time operator. In the case of the diesel system, labor costs were assumed to be included in the figure for annual maintenance. The sensitivity analysis explores the effect of doubling and halving the cost of lubrication and labor.

Fuel Costs

A diesel cost of $0.40/liter (equivalent to $11/GJ) was assumed for the baseline case. This price is typical in rural areas of many developing countries, although in locations where there are major transportation and distribution problems, diesel prices can be substantially higher. The sensitivity analysis examines a range of prices from \$0.30-\$0.60/liter.

A wood cost of \$20/air-dry tonne was assumed, based on estimates of wood production costs in efficiently managed plantations. This figure includes the cost of chipping, where necessary. The sensitivity analysis covers a range of prices from zero to \$40/air-dry tonne.

Interest Rate and Inflation

A real interest rate of 10 percent was used in the baseline case, and the effect of inflation was ignored. Fuel price inflation of up to 9 percent per annum and a range of interest rates from 5 to 30 percent were considered in the sensitivity analysis.

Using these assumptions, the annual costs of running a dual-fuel diesel engine with a wood gasifier were calculated for the three baseline cases. These costs were compared with the corresponding costs for a conventional diesel engine.

The results are given in Exhibit 18.7. They show that with low- and medium-cost gasifiers (Cases A and B), the power from a gasifier system is significantly cheaper than from a conventional diesel system. Power costs worked out at \$0.15/kWh and \$0.17/kWh for Cases A and B, respectively, which represents respective savings of 30 percent and 20 percent when compared with the estimated cost of diesel power at \$0.21/kWh. Expressed as a simple payback period for the gasifier equipment, a low-cost gasifier would pay for itself in roughly 7 months, whereas a medium-cost system would have a payback period of 1.6 years. However, these power costs are clearly much higher than typical electric utility rates.

The results of other cases clearly demonstrate that expensive imported gasifiers are not economically attractive. A sensitivity analysis used to explore the effects of variations in the system parameters on these findings showed that the main factor influencing economics is the capital cost of the gasifier (see Exhibit 18.8), not diesel prices (see Exhibit 18.9).

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Exhibit 18.7

Breakdown of Annual Costs for 50-kW Shaft-Power Systems: Baseline Cases[1]

Cost component	Diesel system	Gasifier system: Case A	Gasifier system: Case B	Gasifier system: Case C
	Annual costs (1984 dollars)			
Annual capital charges[2]				
• Engine	3,440	3,440	3,440	3,440
• Gasifier	--	860	2,290	9,160
Maintenance	750	1,880	2,500	5,500
Additional labor	--	1,000	1,000	1,000
Lubricants	800	1,600	1,600	1,600
Diesel fuel	16,000	3,200	3,200	3,200
Wood	--	2,800	2,800	2,800
Total annual cost	20,990	14,780	16,830	26,700
Overall power cost (dollars/kWh)	0.21	0.15	0.17	0.27
Savings compared with diesel system	--	30%	20%	(+29%)

[1]Costs are estimated on the basis of the assumptions listed in Exhibit 18.6.

[2]Annual capital charges (ACC) are the initial equipment cost (C) annualized over a 6-year period at an interest rate of 10 percent. They are calculated using the relationship:

$$ACC = C \times \frac{i}{1 - (1 + i)^{-t}}$$

where i = annual interest rate and t = lifetime of system.

Case A = low-cost gasifier ($75/kW).
Case B = medium-cost gasifier ($200/kW).
Case C = high-cost gasifier ($800/kW).

Exhibit 18.8

Results of Sensitivity Analysis for Shaft-Power Systems

		Overall power cost (1984 dollars/kWh)			
			Gasifier system		
Variable	Value of variable	Diesel system	Case A	Case B	Case C
1. Diesel cost (dollars/l)	0.3	0.17	0.14	0.16	(0.26)
	0.4*	0.21	0.15	0.17	(0.27)
	0.6	0.29	0.17	0.19	(0.29)
2. Wood cost (dollars/tonne)	0	0.21	0.12	0.14	(0.24)
	2*	0.21	0.15	0.17	(0.27)
	40	0.17	0.18	0.20	(0.30)
3. Charcoal cost (dollars/tonne)	50	0.21	0.16	0.18	(0.27)
	100	0.21	0.19	0.21	(0.31)
	150	0.21	0.23	(0.25)	(0.34)
4. Diesel consumption (l/kWh)	0.3	0.17	0.14	0.16	(0.26)
	0.4*	0.21	0.15	0.17	(0.27)
5. Wood consumption (kg/kWh)	1.0	0.21	0.14	0.16	(0.26)
	1.4*	0.21	0.15	0.17	(0.27)
	1.8	0.21	0.16	0.16	(0.28)
6. Extent of diesel replacement	100%	0.21	0.12	0.14	(0.24)
	80%*	0.21	0.15	0.17	(0.27)
	50%	0.21	0.19	0.21	(0.31)
7. Extent of engine derating	0%*	0.21	0.15	0.17	(0.27)
	15%	0.21	0.15	0.18	(0.27)
	30%	0.21	0.17	0.19	(0.29)
8. Engine cost (dollars/kW)	150	0.19	0.12	0.14	(0.24)
	300*	0.21	0.15	0.17	(0.27)
	600	0.25	0.20	0.22	(0.32)
9. Maintenance, labor, and lubricants	Low	0.21	0.12	0.14	(0.23)
	Medium*	0.21	0.15	0.17	(0.27)
	High	0.21	0.18	0.20	(0.33)
10. Annual operating period (hours)	500	0.31	0.28	(0.34)	(0.06)
	2,000*	0.21	0.15	0.16	(0.27)
	8,000	0.18	0.12	0.13	(0.17)
11. Lifetime of gasifier system (years)	3	0.21	0.18	(0.21)	(0.36)
	6*	0.21	0.15	0.17	(0.27)
	9	0.21	0.14	0.16	(0.24)
12. Interest rate	5%	0.21	0.14	0.16	(0.25)
	10%*	0.21	0.15	0.16	(0.27)
	20%	0.22	0.16	0.19	(0.31)
	30%	0.23	0.18	0.21	(0.35)
13. Annual oil price inflation	0%*	0.21	0.15	0.17	(0.27)
	3%	0.22	0.15	0.17	(0.27)
	6%	0.24	0.16	0.18	(0.28)
	9%	0.25	0.16	0.18	(0.28)

Notes: see next page.

*Baseline case.

Case A = low-cost gasifier ($75/kW).
Case B = medium-cost gasifier ($200/kW).
Case C = high-cost gasifier ($800/kW).

Numbers in parentheses indicate that power from the gasifier system is <u>more</u> expensive than from the corresponding diesel system.

Notes to Exhibit 18.8

1. The cost of lubricants is defined as a proportion of diesel costs, and varies with changes in the diesel price.

2. Prices include the cost of chipping.

4. Diesel consumption figures refer to the diesel system. Diesel consumption of the gasifier systems is assumed to be a constant proportion (20 percent) of these figures.

5. Wood consumption of 1.0, 1.4, and 1.8 kg/kWh correspond to gasifier efficiencies of 78, 55, and 43 percent, respectively.

6. Diesel and wood consumption at different levels of diesel replacement were assumed to be as follows:

Percentage replacement	Diesel consumption (liters/kWh)	Wood consumption (kg/kWh)
100	--	1.75
80	0.08	1.40
50	0.20	0.88

7. 15% and 30% derating implies that larger engines will be required to provide the same peak power output (59 kW and 71 kW, respectively). Capital cost of the engine and maintenance costs, therefore, are increased accordingly.

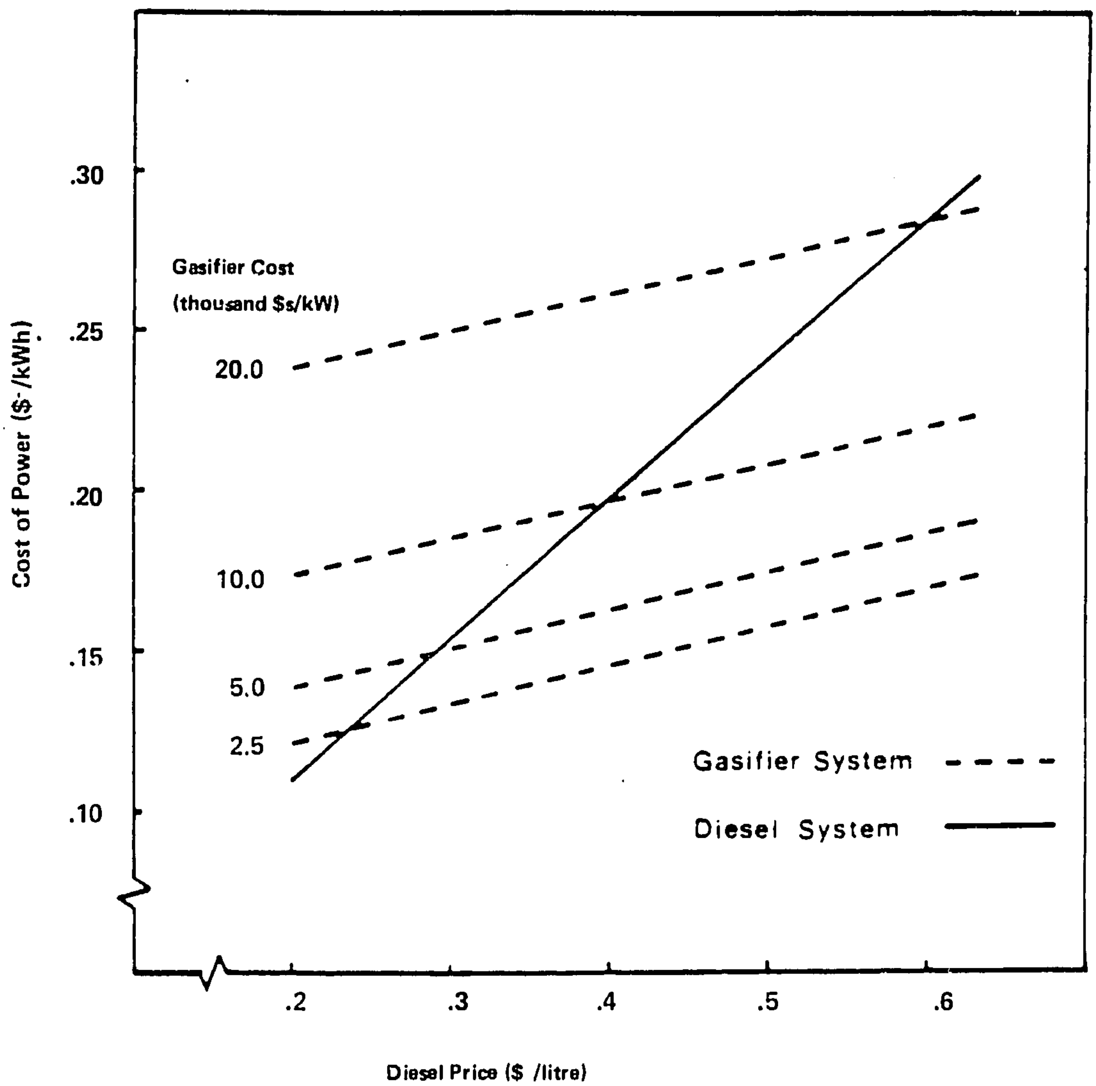
9. Maintenance, labor, and lubricant costs were assumed to be half and double those listed in Exhibit 18.6 for the baseline cases for the low and high cost cases, respectively.

10. Maintenance, labor, and lubricant costs were all assumed to be directly proportional to the length of the annual operating period and were altered accordingly.

13. Figures refer to annual oil price (diesel price) inflation over and above the general rate of inflation.

Exhibit 18.9

Comparison of Diesel and Gasifier Systems - Effect of Diesel Price and Gasifier Cost



SAFETY AND HAZARDS

Unless stringent safety precautions are taken, gasifier operation can be dangerous. The safe operation of most machinery requires care and proper precautions, but special dangers arise in the case of gasifiers because of the high carbon monoxide content of the gas they produce and the possible risks from fire and explosions.

Carbon monoxide is a colorless, odorless gas with about the same density as air. When breathed, it is preferentially taken up by the hemoglobin in the blood. The affinity of hemoglobin for carbon monoxide is about 250 times greater than for oxygen. A person breathing an atmosphere containing carbon monoxide thus begins to become starved of oxygen. At a concentration of 0.5 percent by volume in the air, unconsciousness results in 2 to 4 hours, depending on the level of activity (and hence rate of breathing) of the victim. If higher concentrations are inhaled, death may ensue immediately. The poisoning effect has been described as comparable in speed with an acute cerebral hemorrhage or serious coronary thrombosis.

Inhaling minor amounts causes dizziness and lack of concentration. A person suffering from mild carbon monoxide poisoning will tend to become careless and less aware of the need for safety precautions. In the case of a small leak into the driver's cab of a gasifier-fueled vehicle, the driver may begin to show symptoms similar to those of alcohol intoxication and become a serious danger to himself and other road users.

In much of the contemporary literature on gasifiers, far too little attention is given to this aspect of the technology. The hazards of normal engine exhaust gas, which contains 6 to 7 percent carbon monoxide, are well known; leaving a vehicle running in a closed garage is a common cause of both accidental death and suicide. In producer gas, the carbon monoxide component is normally at least 20 percent, and may reach 30 percent under certain conditions. It is thus very much more hazardous than normal engine exhaust gas.

When a gasifier is operating normally, it is under a negative pressure because of the suction created by the engine or fan system used to draw air through the gasifier. The risks of a leak, therefore, are small. If a supercharger is used, however, a positive pressure is created, and precautions against any welding defects or loose connections must be correspondingly increased in all the portions of the equipment under pressure.

The most hazardous time with shaft-power systems is usually when the engine ceases operation. Gas continues to be produced in the gasifier, and a positive pressure builds up inside it. Gas leaks may occur through defects in manufacture or simply because of imperfect sealing of the loading-hopper lid. Precautions also must be taken when cleaning and repairing a gasifier, since the amount of residual gas in the unit may be sufficiently large for it to be dangerous. The exhaust gases from an idling gasifier-powered engine may also contain considerably more carbon monoxide than those from a normal engine.

A gasifier should never be sited in a building without a high degree of natural ventilation. A large portion of the wartime accidents resulted from working inside garages with vehicle gasifiers in operation. The need for security and protection against weather must not be allowed to dictate a degree of enclosure in which accumulations of gas could occur. Stacking of fuel and other materials around the gasifier must be arranged to ensure that the space is fully ventilated. The venting of the engine must be such that gas cannot accumulate or reach significant levels of concentration in nearby buildings.

Seventeen people were killed in Sweden between December 1939 and March 1941 as a result of failure to observe the necessary precautions in gasifier operation. Generator gas illness became Sweden's most common occupational disease in the early war years. Even at levels which do not cause symptoms of illness, carbon monoxide may be a cause of fetal damage.

Precautions must also be taken against explosions and fires caused by gasifiers. Explosions can occur for a number of reasons. If refueling is delayed too long in a batch-fed system, the temperature of the pyrolysis gases in the region above the feedstock can rise to ignition temperature. When the cover is opened for refueling, the entry of air resulting from the slight vacuum in the system may cause an explosive mixture to form. The result is a minor explosion or rapid flare-up of the gases. In World War II, there were thousands of vehicle fires as a result of such incidents. Between 1939 and 1944, the number of fires reported to the Swedish Gas Generator Bureau was 2,865.

An eloquent commentary on the risk is given in another wartime publication in which drivers are advised to carry a fire extinguisher and a pail of water to prevent forest fires, since "from a country lane or a field it is often not far to the woods, and a burning vehicle may set fire to the trees."

Another time of risk is after the gasifier has been shut down. The residual combustion of the fuel causes an accumulation of gas to occur, which may cause an explosion when the gasifier is next ignited. It is therefore essential that the equipment is thoroughly ventilated before any attempt at re-ignition is made.

The tars produced in a wood-fueled gasifier are also a potentially serious environmental hazard. They can kill fish life if discharged into watercourses, or render water unfit for drinking. In large quantitices, they can put a normal sewage works out of action by killing off the bacteria in the sludge digestion plant. They may also be carcinogenic.

With care and proper safety precautions, gasifier technology an be made to work to a perfectly adequate level of safety. However, a full recognition of its hazards is required. It is not a technology for the technically unsophisticated or those likely to neglect safety precautions. Producer gas should never be considered as a village cooking fuel.

Units and Conversion Factors

Units

1 Gigajoule (GJ) = 10^9 joules
1 Megajoule (MJ) = 10^6 joules
1 GJ = 0.95 x 10^6 Btu
1 GJ = 0.24 x 10^6 kilocalories
1 GJ = 280 kilowatt-hours (kWh)
1 kilowatt (kW) = 1.34 horsepower
1 GJ/hour = 25.4 boiler horsepower
1 GJ/hour = 410 kg steam/hour
1 hectare = 2.47 acres
1 cubic meter (m^3) = 35.3 cubic feet
1 tonne = 1,000 kg = 2,205 lbs

Energy content of fuels*

Fuel oil = 43 GJ/tonne
Natural gas = 38 MJ/m^3
Gasoline = 32 MJ/liter
Diesel = 36 MJ/liter
Charcoal = 30 GJ/tonne
Oven-dry wood = 20 GJ/tonne
Air-dry wood = 15 GJ/tonne (20% moisture)

*All values are approximate.

APPENDIX 18.A: TECHNICAL CONSIDERATIONS FOR USE OF PRODUCER GAS

In this appendix, technical modifications and specific considerations for using producer gas in shaft-power and direct-heat systems are discussed.

SHAFT-POWER SYSTEMS

In principle, any internal combustion engine can be converted to run, either wholly or in part, on producer gas as fuel. In practice, there may be considerable problems in the conversion of a particular make of engine, and in some cases, it may be completely impractical. Some of the very fast-running modern automobile engines, for example, are not suitable for running on producer gas.

Spark-Ignition Engines

Most spark-ignition engines use gasoline as fuel. These engines are the type used in the majority of automobiles. Some diesel engines also operate with spark ignition. In both cases, it is theoretically possible to convert the engine to run entirely on producer gas.

The precise alternations will depend on the engine make, its intended application, and the degree of control required on its running. In essence, the conversion is quite simple: the gas pipe from the gasifier is connected to the air inlet manifold of the engine, and a throttle control mechanism is fitted to regulate the flow of gas and air.

In some engines, alterations also must be made to the inlet ports of the engine cylinders, and the spark plugs may need to be changed. In addition, the ignition timing generally has to be advanced to as much as 35 to 40 degrees before top dead center in the case of high-speed engines. The correct changes in any particular case will have to be determined by skilled and knowledgeable experimental work, but carrying them out and fitting the gasifier is within the scope of a reasonably well-equipped mechanical engineering or motor repair shop.

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The simplest conversion is when the engine is altered to run entirely on producer gas without any provision for an auxiliary gasoline supply. In this case, the gasoline pump becomes redundant and the carburetor can be removed or bypassed. In vehicle applications, however, these parts are often retained so that it is still possible to use gasoline for starting the engine and for giving additional power when accelerating or climbing hills.

When a spark-ignition engine is converted to operation on producer gas, there is a substantial decline in its rated power output. **Usually, this derating amounts to 40-50 percent.** This is not a decline in the efficiency of the engine, as is sometimes described, but merely a reduction in the maximum power that it can deliver. Derating occurs for a number of reasons. The principal cause is the low energy density of the producer-gas-air mixture, compared with a gasoline/air mixture, which alone can lead to a 30-percent loss of power. The pressure drop that results from the need to create a suction through the gasifier and the gas-cleaning equipment is an additional factor. Power is also lost if the gas temperature is higher than that of the ambient air.

Various measures can be taken to reduce these losses. In some engines, it is possible to increase the compression ratio, but this tends to shorten the engine life and may make starting the engine more difficult. Another approach is to use a fan or supercharger in the gas feedpipe, which increases the pressure of the gas reaching the engine and, to some extent, compensates for the power losses. However, it does increase the cost and complexity of the equipment. The practice of supercharging the whole gasifier plant by increasing the pressure inside the gasifier vessel adds greatly to the risk of leaks and is not generally recommended.

The fact that the rated output of an engine is lower when running on producer gas is not necessarily a serious problem. Few engines are run at their maximum power, particularly in stationary applications. In fact, the installed capacity of the engine in most cases is well above that required for its function. This oversizing means that the power output will generally be adequate even when run on producer gas.

Ideally, an engine running on producer gas should have a relatively slow speed. Engine speeds of around 1,500 rpm are widely regarded as being about the optimum. At higher engine speeds, performance usually drops off. One of the main reasons for this lower performance is the slower rate of flame-propagation inside the engine cylinder of a gas/air mixture, compared with a gasoline-air mixture. Experience in the Philippines and elsewhere, however, indicates that the decline in performance is not too serious a problem up to engine speeds of about 3,000-4,000 rpm. Very high-speed engines are generally thought to be unsuitable for conversion to producer gas.

Compression-Ignition Engines

Most diesel engines work on the compression ignition principle. Fuel is injected into the cylinder by an injection pump, and the fuel/air mixture is ignited by the increase in temperature caused by the upward movement of the piston. In theory, any compression-ignition diesel engine can be converted to run on producer gas, but because producer gas does not have the necessary self-ignition properties, diesel cannot be dispensed with entirely. A certain minimum injection is required to ensure that ignition occurs during each engine cycle. Around 10 percent of the normal fuel injection is usually needed, although in some cases slightly less will suffice. This type of operation, where gas and diesel are used together, is referred to as **dual-fuel operation.**

Again, the exact changes necessary will depend on the make of engine, its application, and the control systems required. In practice, not all diesel engines are suitable for conversion. Some of the problems center around the fuel injection systems. Those with direct injection are generally the most suitable; those in which the fuel is injected into an antechamber to the cylinder are more difficult to convert. The actual alterations required are similar to those for a gasoline engine; a gas inlet must be provided to the air intake manifold of the engine, and air and gas throttle controls must be fitted. The work requires roughly the same workshop facilities and a similar level of technical skills as required for converting gasoline engines.

Diesel engines tend to run at somewhat slower speeds than gasoline engines, and are generally regarded as being better suited for conversion to producer gas. The loss of power when converted to gas is also lower than with gasoline engines, due in part to their higher compression ratio. A derating of 20 percent is typical when running with the minimum fuel injection.

It is also possible to convert a compression-ignition engine to run entirely on producer gas. Such conversion requires fitting it with spark plugs and their ignition system, removing the fuel injection equipment, and making any necessary alterations to the method of lubrication. It is a major, and rather costly operation, but the resulting engine has considerable merits. It has the robustness and high compression ratio typical of the diesel engine, while at the same time it is freed of any dependence on diesel fuel for ignition. In some instances, these advantages may be judged sufficient to compensate for the extra cost and complexity of the conversion.

Gasifier Operation and Control

Starting a gasifier can be a distinctly troublesome exercise, especially in cold or wet weather. The fuel is kindled at an ignition port, and a draft must be created to pull air into the gasifier. With a dual-fuel diesel system, this is done by starting the engine on diesel and using its suction to draw air through the gasifier.

With spark-ignition engines converted to using gas only, this method of starting is not possible, and the engine cannot run until the gas-production level is adequate. To achieve this level, a draft through the gasifier must be created by a hand-operated or battery-operated fan.

Gasoline engine systems in which the gasoline pump and carburetor have been retained can be started in the conventional fashion using gasoline and subsequently switched over to running on gas once the engine is going. The switch-over can be difficult and requires a certain amount of skill and mechanical aptitude.

Some modern gasifier designs claim a normal starting time of 3-5 minutes, but it may be much longer. A stop of about 30 minutes is usually feasible without having to relight the gasifier or encountering problems in bringing it back to full load relatively quickly. Stops of up to 6 hours in which the fire is banked down, but not extinguished, may also be possible.

Most practical applications of gasifiers require an ability to respond reasonably quickly to changes in the load on the engine. The inherent operating characteristics of a gasifier are somewhat of an obstacle to this desirable characteristic. A change in gas output requires an expansion or contraction of the combustion zone in the gasifier, which is relatively slow in comparison with the speed with which the power output of a conventional engine can be altered. Some gasifier types, such as the crossdraft, are specifically designed to cope with this problem and provide a rapid response to fluctuations in the load upon them.

Control techniques, therefore, are an aspect of designing gasifier systems to which considerable attention has been paid. With a dual-fuel system, the simplest method of varying the power output is by increasing or decreasing the quantity of diesel fuel injected, while keeping the gasifier output constant. The gasifier thus supplies the base load, and fluctuations are taken up by varying the use of diesel.

An alternative method of controlling the operation of a dual-fuel system is to set the diesel fuel injection to the minimum level and use the gas to take up the load fluctuations. Here, the economy in fuel is maximized, but it happens at the expense of the reaction time of the system to changes in load. It also means that the gasifier is frequently operating outside its optimum conditions, thus increasing the problems with tar production. Spark-ignition engines that have been converted to run solely on producer gas suffer from the same problems.

Stationary gasifier units are somewhat easier to design and build than those for vehicle applications in that they are subject to fewer restrictions on their weight and layout. On the other hand, stationary engines are normally expected to function without an operator in constant attention, which requires a much higher degree of automatic control than with mobile units and greatly increases the cost and complexity of the system. In many developing-country applications, providing a full-time attendant will be more cost-effective than buying a completely automated gasifier.

Electricity generation also requires special care. Here it is generally highly desirable that the generator speed remains constant to prevent fluctuations in the frequency of the current. With modern control systems, a diesel generating set requires perhaps a couple of seconds to respond to a change of load of 25 percent. Such fluctuations are extremely common in the small electricity grid systems installed in many developing countries. The response-time of most downdraft gasifiers may be 10-15 seconds or longer, given a load change of this magnitude. These differences in response characteristics make it difficult to run a gasifier-powered generating set in parallel with a diesel set, or even with another gasifier-powered unit. In effect, this means that gasifiers cannot yet be integrated into an electricity grid system with any degree of assurance. Their use in electricity generation in developing countries, therefore, is largely restricted at present to isolated units driving single generating sets.

An ingenious method of circumventing this problem is possible, however, in places where there is a large electricity grid and an electricity authority that is willing to cooperate. Rather than using a gasifier-powered engine to drive a generator, it can be coupled instead to an induction motor that is itself connected into the grid. The induction motor can be used as a generator, feeding back into the grid and thus earning a credit from the electricity authority. The inertia of the grid is sufficient to act as a flywheel and maintain the speed of the motor despite any fluctuations in the gasifier output.

In summary, running a gasifier is a relatively complex operation, particularly if full advantage is to be taken of the opportunity to save liquid fuel. It is not something that can be easily handled by technically unqualified people. Although many combinations of controls are possible that simplify the task of obtaining optimum running, full automation is both difficult and expensive. Under normal operating conditions, and particularly where the level of operating skill is low, the saving in dual-fuel operation will be far below the theoretical maximum of 80-90 percent; a figure of 50 percent is probably a much more reasonable assumption.

Gas Cleaning and Cooling

An internal-combustion engine requires gas that is free of tar, dust particles, and excessive water vapor, and is as close to the ambient temperature as possible.

Tar is extremely troublesome if it gets into the engine. It can cause sticking of the valves, coking in the cylinders, and in extreme cases may require dismantling of the engine for cleaning, or complete engine replacement. The primary aim of a gasifier designer is to prevent the problem at its source and break down the tars inside the gasifier. Any tar that does escape must be captured in the cleaning system so that only minimal amounts reach the engine. The Swedish wartime experience indicated that acceptable engine performance can be achieved with a tar content in the gas of up to 0.6 gm/m^3.

Cooling the gas is required for thermodynamic reasons. Raising the inlet temperature of the gas at the engine by 20°C causes a reduction in power output of around 3 percent. Lowering the gas pressure below atmospheric also reduced the power; a drop of 100 mm water pressure lowers the engine output by 1 percent.

Given engine requirements such as these, the type and degree of sophistication in the cleaning and cooling equipment will depend on the temperature and quality of the gas leaving the gasifier. This, in turn, is a function of the gasifier design, the way it is run, and the quality of the fuel used. As a consequence, cleaning and cooling systems vary considerably. The simplest systems, dealing with clean uniform-quality gas, need incorporate no more than dust extraction and cooling devices. Where the gas is heavily contaminated, more elaborate filtering and scrubbing devices are required as well.

Each element in the cleaning system causes a pressure drop in the gas in addition to the decline that occurs in drawing the gas through the gasifier itself. A tradeoff, therefore, must be made by the system designer. Producing a clean gas places demands on the design and operation of the gasifier and restricts the fuel that can be used. Cleaning a dirty gas, on the other hand, is costly in equipment and increases the pressure drop. A total pressure drop across the system of 1,000 mm of water is generally felt to be about the maximum acceptable.

DIRECT-HEAT SYSTEMS

Direct-heat gasifier systems are those in which producer gas is burned directly in a furnace or boiler, instead of being used in engines. Because the gas quality is less critical than in shaft-power applications, direct-heat systems are not as demanding technically and are more versatile in the fuels they can use.

Only a handful of systems are commercially available at present, most of them made by companies in the United States, Canada, and Brazil. Operating experience is limited to a few dozen units worldwide, most of which have been running for no more than a year or two.

Although a number of technical problems have emerged in the development of direct-heat gasifiers, most of them have proved to be avoidable through careful design.

Design Considerations

Because gas quality is less important, the main emphasis in the design of direct-heat gasifier systems is on other factors. Depending on the application, these factors can include maximizing thermal efficiency, minimizing the size of units so that they can fit into existing boiler rooms, automating the operation as much as possible, widening the range of acceptable fuels, and improving the degree of control over the process.

Most of the direct-heat gasifiers currently available are of the updraft or fluidized-bed types. Precise designs vary considerably, and most of the systems on the market contain proprietary features that are protected by patents. The main differences between systems tend to be in the techniques used for adding the fuel and removing the ash, and in the method of supplying air to the gasifier.

Most of the systems developed in North America are completely automated and operate continuously, rather than by batch feeding. This means that the feedstock is continually added to the reactor, and air is supplied in an appropriate quantity using a variable-speed fan. A variety of novel approaches has been developed for achieving controlled gasification in this fashion. The Biotherm gasifier, for example, produced by C.H.H. Technology, Inc., employs an entrained-bed technique in which the majority of the gasification occurs in suspension as the fuel falls by gravity through the gasification chamber. In the Forest Fuels system, biomass is added to a moving grate that is constructed in the form of a continuous belt. As the grate moves, the fuel is gradually gasified. When it reaches the end of the belt, the resulting ash is deposited in a disposal chamber.

The thermal efficiency of direct-heat systems tends to be higher than that of most shaft-power gasifiers because the gas does not have to be cooled or cleaned before it is used. Efficiencies of 75-85 percent are typical, using air-dried wood as a feedstock, at roughly 20 percent moisture content on a wet basis.

Most of the direct-heat gasifiers currently on the market have an output in the range of 0.25-25 GJ/hr, but there are no inherent reasons why larger or smaller models could not be produced. With very large systems, the main technical problems are likely to be in controlling the flow of fuel and air inside the gasifier, rather than with the basic thermochemistry. A wood feed of between 400-450 kg/hr is required for a unit with an output of 5 GJ/hr. This is roughly equivalent to the wood consumption of a 250-kW shaft-power system.

Fuel Specifications

The general flexibility of direct-heat gasifiers in the fuels they will accept is greater than that of shaft-power systems. Individual systems, however, tend to have precise specifications for their fuels, which must be rigorously observed for reliable operation.

The moisture content of feedstocks is one of the most important characteristics. Some systems can accept fuels containing up to 50 percent moisture, and are designed so that the water is driven off once the fuel is inside the gasifier. There are disadvantages, however, in the use of wet fuels. The efficiency of the gasifier is impaired, tar production is greater, and the heating value of the final gas is reduced.

In most designs, a reasonably dry feed material is essential (less than about 30 percent moisture). When the gas is being used to produce a high-temperature flame, the moisture content must be no more than 10 percent. Unless a guaranteed supply of ready-dried feed is available, a drying stage usually has to be incorporated as part of the fuel preparation. In many applications, drying can be conveniently achieved by using waste heat from the boiler or kiln to which the gasifier is coupled. Even if it is not essential, drying has the advantage of improving the thermal efficienicy of the gasification.

The size and flow properties of the fuel are also important. Some systems require a clean and very uniform fuel, such as pulp-grade wood chips. When this is the case, size-reduction and screening may be necessary in preparing the fuel. Other designs can take a variety of fuels, ranging from sawdust to nut shells and agricultural wastes. Fuels that contain a large amount of ash or grit can cause problems with clinker formation.

Operation and Control

As with shaft-power systems, starting up a direct-heat gasifier can be time-consuming and rather tricky. The fuel inside the gasifier must be lit, and a suitable draft must be created to kindle and spread the fire. Once the fire is going, the air supply and fuel feed rate must be adjusted so that they reach the appropriate steady state.

In some systems, starting is done manually by using an ignition port and controlling the draft and fuel feed by hand. In more advanced systems, the starting-up is automated, using timing devices or a microprocessor. A small oil burner is sometimes used to light the fuel, and temperature probes can be fitted to provide the feedback information necessary to control the draft and rate of fuel addition. As a result of careful experimentation, a number of manufacturers have managed to develop control systems that can provide fully automatic start-up of the gasifier.

Once the gasifier has reached its working load, the control problem becomes one of matching its output with the heat demand of the unit it is supplying. If the demand changes, the fuel feed rate and the air supply must be adjusted accordingly and in a constant proportion so that the volume of the gas output changes without seriously altering its composition.

Small fluctuations in heat demand can be accommodated fairly easily, provided that the primary air supply and the fuel feed rates can be accurately controlled. Feedback control systems can be designed so that the response to load changes becomes automatic. In boiler applications, for example, this can be done conveniently by monitoring the steam pressure in the boiler.

Major fluctuations in heat demand are more difficult to cope with, and different gasifier designs have different degrees of flexibility. Some are designed to work only in an "on or off" mode, and are best suited where the load is steady. In others, the output can be varied by a factor of five or so, although the efficiency may suffer somewhat at low operating levels.

If very wide variations in load must be accommodated, or rapid response is necessary, it is difficult for direct-heat gasifiers to compete with conventional oil- or gas-fired burners. On the other hand, their response characteristics are substantially better than most solid fuel boilers and furnaces.

Gas Use

The gas produced by most direct-heat gasifiers is both hot and dirty. As it emerges, it will typically be at 250°C-350°C, a temperature at which any tars present will be in the vapor stage. If the gas is allowed to cool, thermal energy will be lost and condensation of tars will occur.

The simplest application for direct-heat systems is where gasifiers are positioned directly adjacent to the appliance where the gas is used, which may be a converted oil-fired boiler, a kiln, or a dryer. In such cases, the gas can be passed directly to the burner where, when mixed with secondary air, it spontaneously ignites, producing a flame that is approximately equivalent to that obtained with oil or natural gas. A gasifier fitted in this way is sometimes described as "close-coupled."

Because of the low energy content of the gas, typically 3.8-5.6 MJ/m^3 (which is approximately 10-15 percent that of natural gas) special burners are generally needed. Some manufacturers have also found that preheating the secondary air helps to maintain a stable flame. If the heating value of the gas drops below about 2.0 MJ/m^3 from using a very wet fuel, or because too much primary air is being fed into the gasifier, maintaining the stability of the flame can become a major problem.

The quality of gas required varies greatly between end uses and has a considerable bearing on the design of the gasifier and the type of fuel it can use. In certain applications in the ceramics and glass-making industries, an extremely clean high-temperature flame is required. Normally, this can be provided only by using natural gas or a light fuel oil. Matching this performance with a direct-heat gasifier requires extremely careful control over the fuel quality and the operation of the gasifier. The Hatsuta "Cargas" system claims a flame temperature of up to 1,950°C as a result of using specially-prepared charcoal with a low moisture content. Other manufacturers such as Thermoquip and Omnifuels report temperatures of over 1,600°C using dry wood fuel and measures such as preheating of the secondary combustion air.

If the gasifier cannot be located close to the burner, special precautions must be taken to prevent the tars from condensing in the gas feed pipe. Insulation of the pipe can be effective over short distances. If the gas has to be piped more than 30-40 meters, however, problems start to mount. Scrubbing out the tars as the gas leaves the gasifier or artificially heating the connecting pipe are two possible solutions, but both are expensive and may not always be effective.

SESSION 19: ON-SITE INDUSTRIAL POWER GENERATION

On-site power generation at industrial plants is an old and common practice worldwide. Besides the traditional standby generation capacity used during interruptions of electric utility service, industries use on-site power generation to displace purchased electric utility power. Using self-generated power to displace purchased power can occur on a continuous basis, displacing all purchased power, or on a periodic basis, displacing purchased power during peak demand periods of the electric utility.

There are basically two categories of on-site industrial power generation: cogeneration and small power generation. In the broadest terms, cogeneration denotes any form of the simultaneous production of electrical or mechanical power and thermal energy (usually in the form of hot gases or liquids) from the same system. In contrast, small power generation denotes the production of electrical or mechanical power only.

In general terms, the potential benefits of on-site industrial power generation are widely recognized and include:

- Industrial benefits
  - reduced energy costs (e.g., using waste fuels for on-site power generation can be less costly than purchasing from the utility electricity generated from oil)
  - enhanced reliability of power supply (e.g., by generating their own power requirements, remote and isolated industrial facilities can either reduce or eliminate the need for electric power purchases from an electric utility, thereby eliminating the need for the utility to construct and maintain expensive electricity transmission equipment)
  - improved quality of power supply (e.g., by self-generating power, industrial facilities that require high-quality electric power can either control or eliminate unacceptable voltage transients and frequency shifts that may occur in utility-generated power)

- National benefits

  - primary fuel savings (e.g., reduction in imports of expensive premium fuels for utility power generation)
  - reduced (or deferred) capital expenditures for construction of electric utility power plants (e.g., reduced debt financing in international capital markets)
  - enhanced quality of electric utility service (e.g., on-site industrial power generation facilities can represent dispersed sources of electric power in close proximity to major load centers in prolonged periods of electric utility emergencies).

Of all these potential benefits from on-site industrial power generation, the opportunity to save energy (typically premium fuels) is the most significant. As shown in Exhibit 19.1, the amount of premium fuel such as oil to cogenerate steam and electricity is less than the amount of premium fuel required by the industrial firm to produce steam and the utility to generate electricity separately. For small power generation, the savings in premium fuel are realized only when the small power generation facility either is more efficient than the electric utility or uses a cheaper nonpremium fuel such as wood wastes and perhaps coal. As shown in Exhibit 19.2, the savings in premium utility fuels are dramatic, despite the lower efficiency of the small power system.

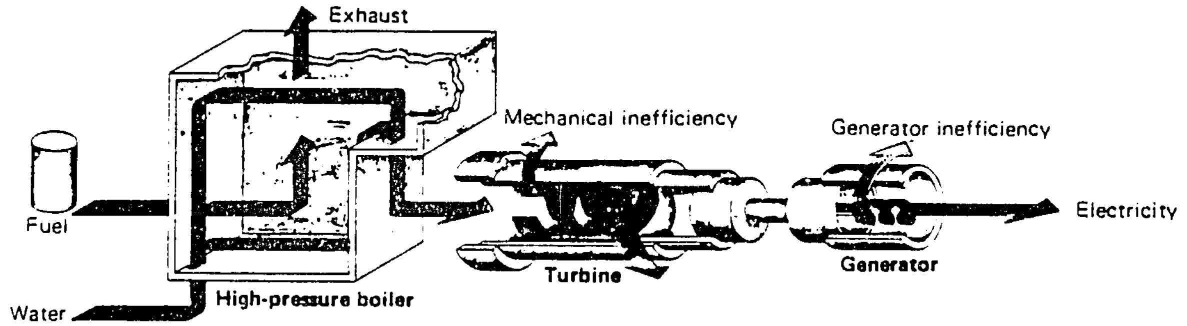
In the following sections, we describe the conventional and commonly-used technologies used in industrial cogeneration and small power systems. In each instance, the performance of each technology and system configuration, the estimated capital cost, and the nonfuel fuel operating and maintenance costs will be discussed.

COGENERATION

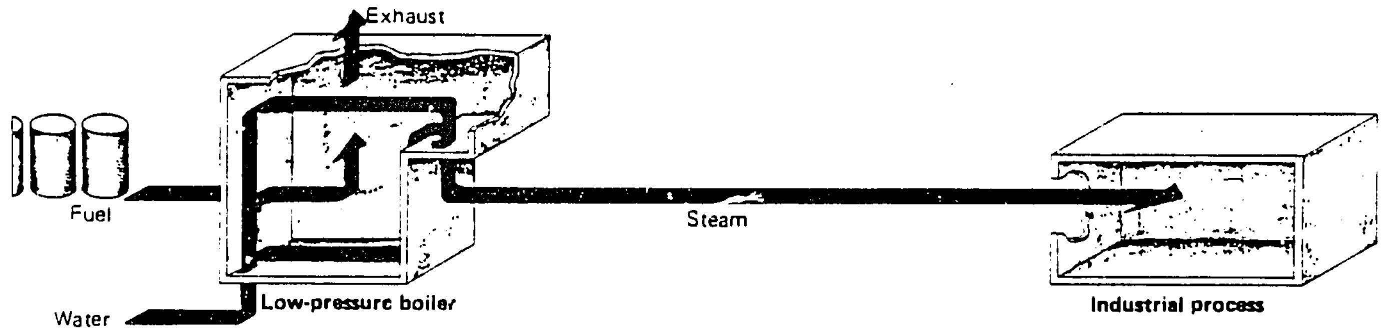
Traditionally, cogeneration systems have been differentiated according to the energy-using sectors in which they are used. For example, total-energy systems are designed to provide electricity, heating, cooling, and sometimes even waste water-treatment services to entire communities. Waste-heat utilization systems and dual-purpose power

Exhibit 19.1
Energy Savings from Industrial Cogeneration

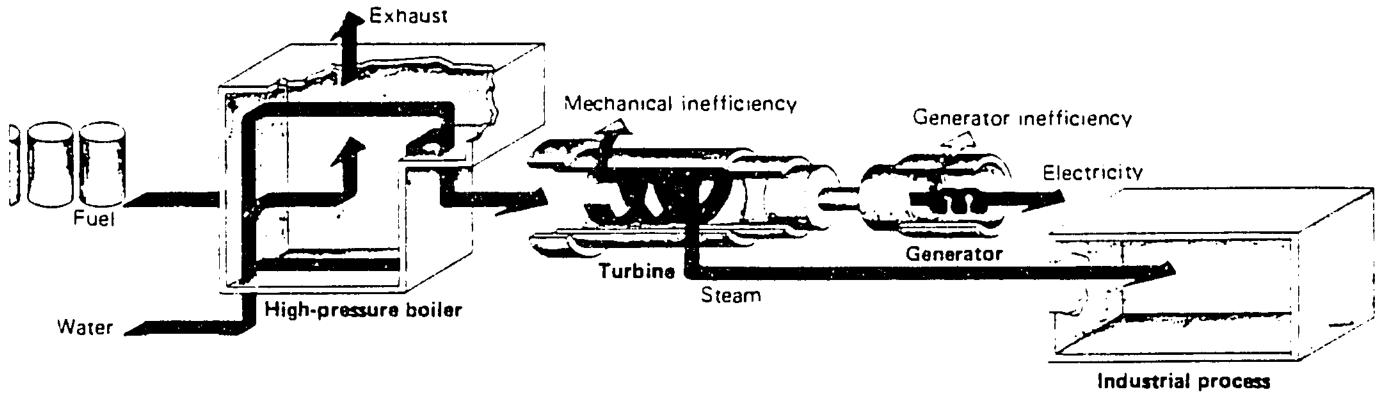
[A] Conventional electrical-generating system requires the equivalent of 1 barrel of oil to produce 600 kWh electricity.



[B] Conventional process-steam system requires the equivalent of 2¼ barrels of oil to produce 3,850 kg of process steam.



[C] Cogeneration system requires the equivalent of 2¼ barrels of oil to generate the same amount of energy as systems A and B.

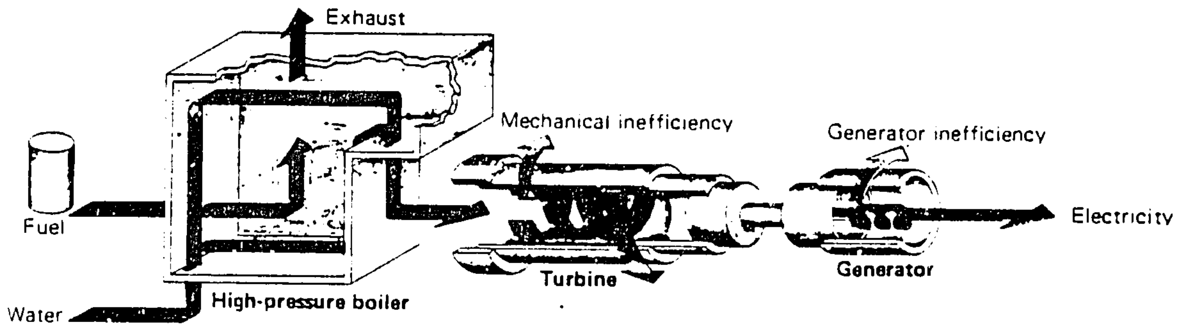


SOURCE: Hagler, Bailly & Company

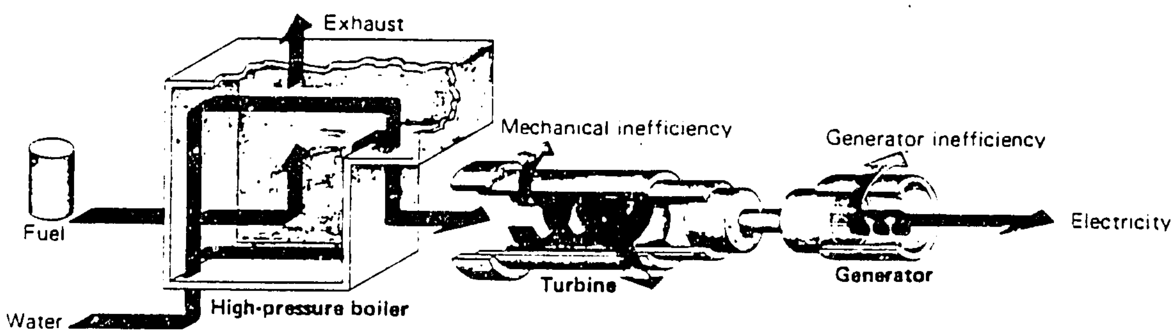
Exhibit 19.2

Oil Savings Resulting from the Use of Biomass in Small Power Systems

(A) Conventional electric generation system requires 1 barrel of oil to produce 600 kWh electr city



(B) Small power system requires no oil to produce 600 kWh electricity, but instead uses wood waste amounting to an equivalent of 2 barrels of oil.



Potential Savings = A-B

Potential Savings $\cong$ 1 barrel of oil for each 600 kWh electricity generated

SOURCE: Hagler, Bailly & Company

plants, on the other hand, have traditionally been used by the industrial and utility sectors.

Technically, there are two fundamental types of cogeneration systems, differentiated on the basis of whether electrical or thermal energy is produced first: topping cycles and bottoming cycles (see Exhibit 19.3). In a topping-cycle system, electricity or mechanical drive is produced first, and the thermal energy exhausted is captured for further use. In a bottoming-cycle system, still-usable thermal enegy is extracted from a waste stream (after it has been used in a process) to produce power, usually by driving a turbine to generate electricity. Both types of systems vary in size and hardware, depending on the specific electrical and thermal needs of the particular industrial application.

Topping-Cycle Systems

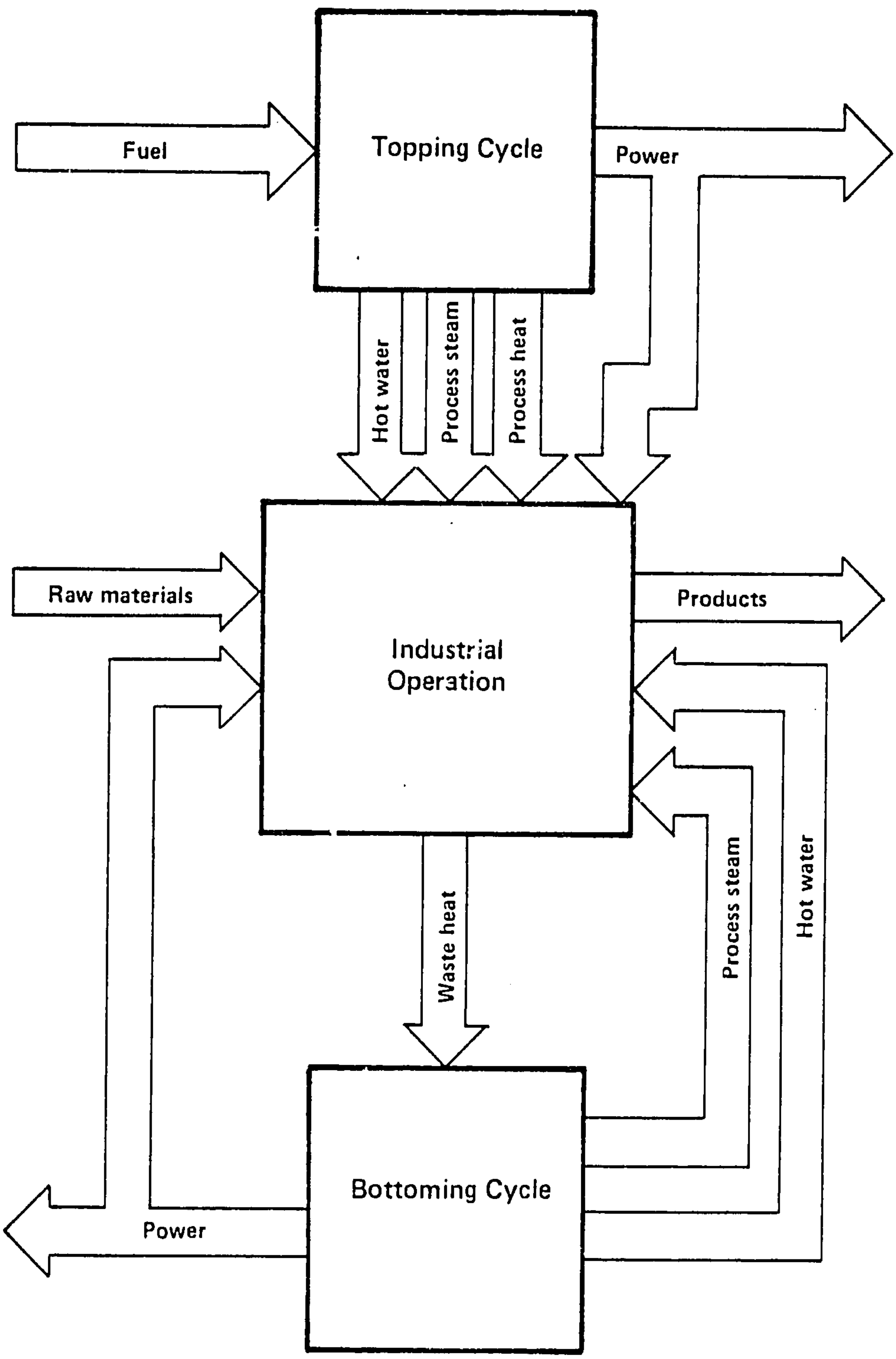
In a **topping-cycle system,** thermal energy exhausted in the production of electrical or mechanical energy is used in industrial processes. Of all the types of industrial cogeneration systems available today, only three have been demonstrated through widespread use to be commercially ready and applicable to the specific requirements of industry: boiler/steam turbine; combustion turbine/heat recovery boiler (and/or heat exchanger); and reciprocating engine/heat recovery boiler (and/or heat exchanger). As shown in Exhibit 19.4, each of these types of cogeneration systems has varying degrees of fuel flexibility and different power and thermal energy generating capabilities. The fuel flexibility of a heat engine, or its ability to operate efficiently using alternative fuels, has become increasingly important in recent years, as the availability of clean-burning fuels such as oil and natural gas grows less certain and the prices of these premium fuels continue to rise.

Boiler/Steam Turbine Cogeneration Systems

The boiler in a steam-turbine system, which generates steam through the combustion of fuel, can be "fired" by oil, natural gas, coal and coal-derived liquids and gases, wood, or synthetic liquids and gases. As shown in Exhibit 19.5, mechanical power is produced

Exhibit 19.3

There are Two Basic Types of Industrial Cogeneration Systems



SOURCE: Hagler, Bailly & Company

Exhibit 19.4

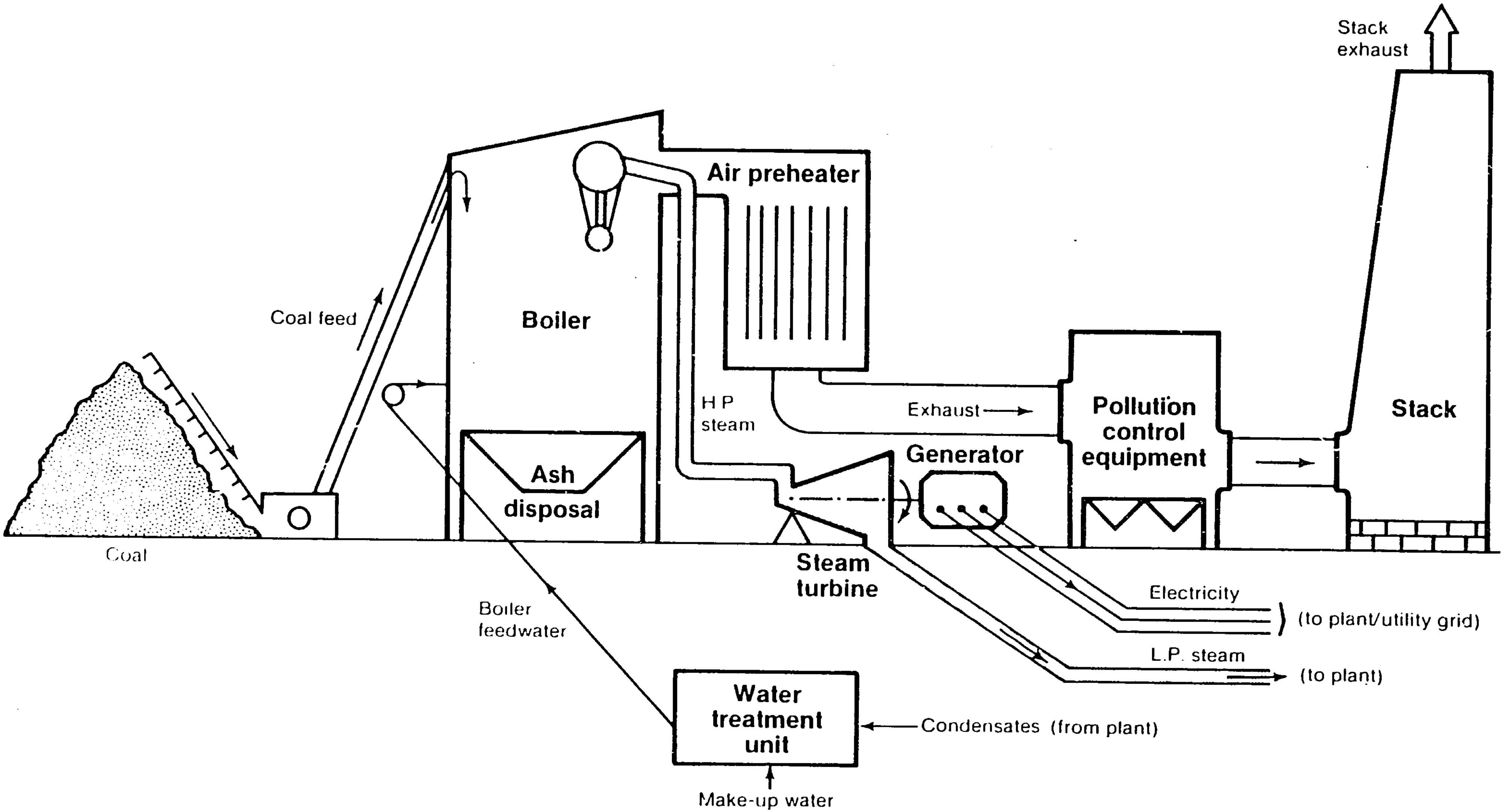
There are three basic types of technologies most suitable for industrial topping cycle cogeneration systems:

		Energy forms produced	
Basic technology	**Type of fuels used**	**Power**	**Thermal energy**
Boiler/steam turbine	Solid, liquid, and gaseous fuels	Mechanical, electrical	Steam, hot water
Combustion turbine/heat recovery boiler (or heat exchanger)	Solid, liquid, and gaseous fuels	Mechanical, electrical	Steam, heat, hot water
Internal combustion engine/heat re-recovery boiler (or heat exchanger)	Liquid and gaseous fuels	Electrical, mechanical	Steam, hot water, heat

Exhibit 19.5

Boiler/Steam Turbine Cogeneration System

H.P. steam = High-pressure steam
L.P. steam = Low-pressure steam



SOURCE: Hagler, Bailly & Company

as the high-pressure steam drives a turbine. The mechanical power can be used directly in driving devices such as pumps, compressors, and conveyors. Through the use of an electrical generator, this mechanical power can be converted to electricity. The low-pressure steam exhaust from the turbine can be used for industrial-process application.

The power boilers in a boiler/steam turbine cogeneration system (as differentiated from process boilers) have the capability of producing steam of sufficient pressure and temperature to drive a steam turbine. With some exceptions, the typical lower limit is approximately 25 bar saturated steam. In most instances, superheated steam (ranging from 40 bar to 100 bar) is produced by power boilers to drive steam turbines.

Power boiler efficiencies depend primarily on size, fuel used, and the moisture content of the fuel. Under normal conditions, the efficiencies of power boilers (in decreasing order) are:

- Coal-fired atmospheric fluid bed boilers: 84-88 percent
- Pulverized coal-fired boilers: 84-88 percent
- Stoker-type coal-fired boilers: 82-86 percent
- Oil-fired boilers: 82-86 percent
- Natural gas-fired boilers: 80-84 percent
- Waste-fired boilers (i.e., black liquor, wood waste, bagasse): 40-70 percent.*

Backpressure steam turbines are available in unit sizes, from a few kW to over 50 MW. Steam can be obtained from the turbine at one or more extraction points to serve a variety of useful functions such as process heating, boiler feedwater heating, and deaeration. However, the only configurations for which the total power generated is considered to be cogenerated are noncondensing backpressure, extraction/noncondensing, and extraction/condensing steam turbines where the noncondensed steam is used for process applications. Because the relative amount and quality of steam delivered to process can vary dramatically for the various types of steam turbines, the power-to-steam ratios can range from about 0.05 GJ/GJ to over 0.40 GJ/GJ.

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*Depends on moisture content, which ranges from 40-60 percent by weight.

The power conversion efficiency of steam turbines in cogeneration configurations varies in general with load conditions, the thermodynamic conditions (pressure and temperature) of the steam at the entry and exit points of the turbine, the size and speed of the turbine, the number and type of turbine stages, and the manufacturer. In the case of noncondensing steam turbines, small (less than 100 kW) single- or double-stage turbines usually have a low efficiency, typically 20 to 50 percent; medium-sized turbines (500 to 5,000 kW) have efficiencies in the 50 to 75 percent range; and very large multi-stage units (greater than 5,000 kW) may have efficiencies exceeding 80 percent. Electric generator efficiencies typically range from 95 to 98 percent. The variation with load is shown in Exhibit 19.6 for non-condensing steam turbines.

The extraction/condensing configuration is favored in those cases where steam and electric loads vary significantly and frequently. The flexibility of this configuration resides in the fact that more steam can be condensed to generate additional power at times when process steam demands are low, or the boiler output can be reduced to give constant or reduced power at different process steam demands. However, in gaining this flexibility with extraction/condensing steam turbines, efficiency is reduced. Depending primarily on size and operating conditions, the efficiency can range from less than 20 percent to about 75 percent.

The major system costs are composed of those costs of the major equipment required for the construction of a boiler/steam turbine cogeneration system and include:

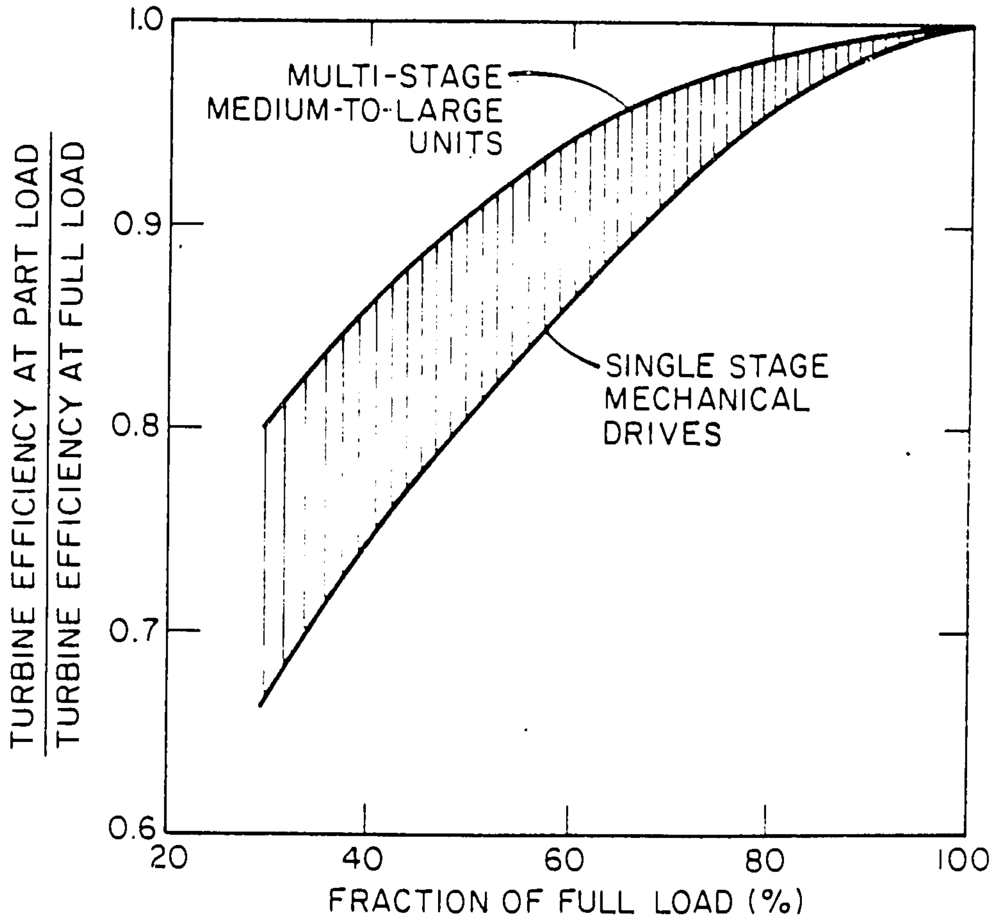
- Fuel handling and storage equipment
- Boilers and ancillary equipment
- Steam turbine (and electric generators)
- Balance of plant (e.g., waste handling, electric substation, control room).

Regardless of the fuel used, the boiler(s) and ancillary equipment represent the most expensive subsystem in the total plant, ranging from 50 percent to 80 percent of the total cost (depending on the system design and fuel used).

Overall, the total installed cost (1982 dollars) ranges from $1,500/kW for a large (approximately 20 MW and greater) oil-fired boiler/steam turbine system to more than $4,000/kW for a small (less than 3 MW) coal- or waste-fired boiler/steam turbine system.

Exhibit 19.6

Non-Condensing Steam Turbines: Variation of Efficiency with Load



SOURCE: Hagler, Bailly & Company

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Depending on size, fuel used, and integration requirements into the industrial plant's processes, installation time can range from less than 1 year to more than 3 years.

Nonfuel operating and maintenance costs are largely dependent on site-specific factors. The cost of spare parts and expendables (e.g., fuel oil filters) depends primarily on the fuel used and varies over the life of the boiler/steam turbine cogeneration system. Roughly, these costs annually average about 1.5 percent of the capital cost of the total system. However, the largest contribution to the nonfuel operating and maintenance costs is labor. The size of the labor force required to operate and maintain the boiler/steam turbine cogeneration system will also vary with the type and size of equipment, but is dependent to a greater extent on the particular industrial plant. For instance, for an industrial plant which does not already generate power, a small boiler/steam turbine cogeneration system (less than 5,000 kW) may require three or more additional skilled laborers per shift, which may be prohibitively expensive when compared with the expected benefits of cogeneration. In contrast, the same personnel investment (three skilled laborers per shift) will be required for a larger (up to 30 MW) boiler/steam turbine cogeneration system, which may be a more acceptable cost when compared with the expected benefits of cogeneration. If the boiler/steam turbine cogeneration system will use coal (or waste) and the existing process boilers use oil or natural gas, the additional nonfuel operating and maintenance costs will be even higher.

Reliability for steam-turbine technology has been high for several decades. Manufacturers usually recommend minor annual inspections and major inspections every 3 years. Replacement parts are readily available, and maintenance schedules can be typically coordinated with operating schedules of the industrial plant.

Gas Turbine Cogeneration Systems

Instead of generating steam to drive a turbine as a means of producing power, the gas turbine burns natural gas or oil and uses the combustion gases to produce mechanical shaft power (or electricity, if connected to an electrical generator). The exhaust gases from the gas turbine can be used to produce steam (or hot water) in a heat recovery boiler and direct heat (i.e., heated air or hot exhaust gases) for industrial process applications. Gas turbines are commercially available in unit sizes ranging from 6 kW to 100

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MW. They can operate on natural gas, refined fuel oil (distillate and residual oil) and crude oil. Dual-fuel units are also commercially available, but dual-fuel units and units capable of burning residual oil and crude oil are available only in sizes exceeding 10 MW.

The gas turbines used in industrial cogeneration systems typically have efficiencies ranging from about 15 percent to just over 30 percent and exhaust temperatures of between 350°C and 500°C. In the predominant method of gas turbine cogeneration in existence today, the exhaust gases are passed through a heat recovery boiler to generate steam for industrial process applications (as shown in Exhibit 19.7). Although not used as frequently, the exhaust gases can either be delivered directly to process for heating applications or passed through an air-to-air heat exchanger to generate hot air for process heating.

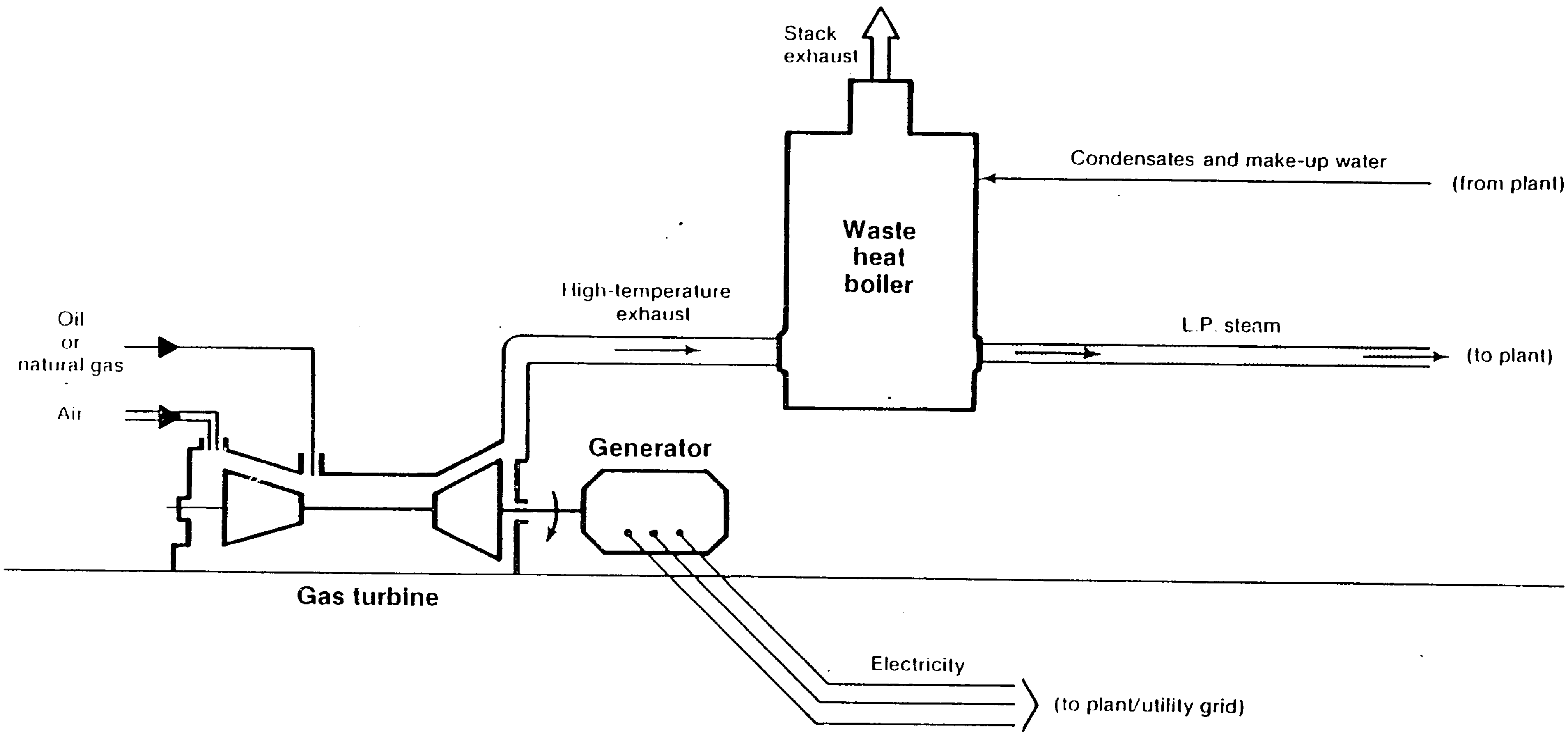
There are four major factors related to the performance of gas turbine cogeneration systems:

- Because the amount of power generated by the gas turbines is strongly affected by the ambient air temperature, the highest prevailing ambient temperature is used in system sizing.
- When natural gas is used as a fuel, a compressor is usually required to increase the pressure of the natural gas entering the combustion chamber.
- The gas turbine efficiency at part load is dramatically lower than that at full load (see Exhibit 19.8).
- Using fuel to directly heat the gas turbine exhaust (or the heat recovery boiler) will significantly change the overall system efficiency and the relative amounts of power and useful thermal energy produced. For instance, the power-to-steam ratio of gas turbine cogeneration systems is typically 0.45-0.90 GJ/GJ for unfired boilers; 0.29-0.60 GJ/GJ for supplementally-fired boilers; and 0.09-0.15 GJ/GJ for fully-fired boilers.

Although the capital costs of a gas turbine cogeneration system depend on many factors (including heat recovery technique, use of additional fuel for increasing quality of recovered waste heat, type of gas turbine design, and fuel used), the primary factor is size. For large gas turbine cogeneration systems (i.e., 10 MW and greater), the total capital

Exhibit 19.7
Gas Turbine Cogeneration System

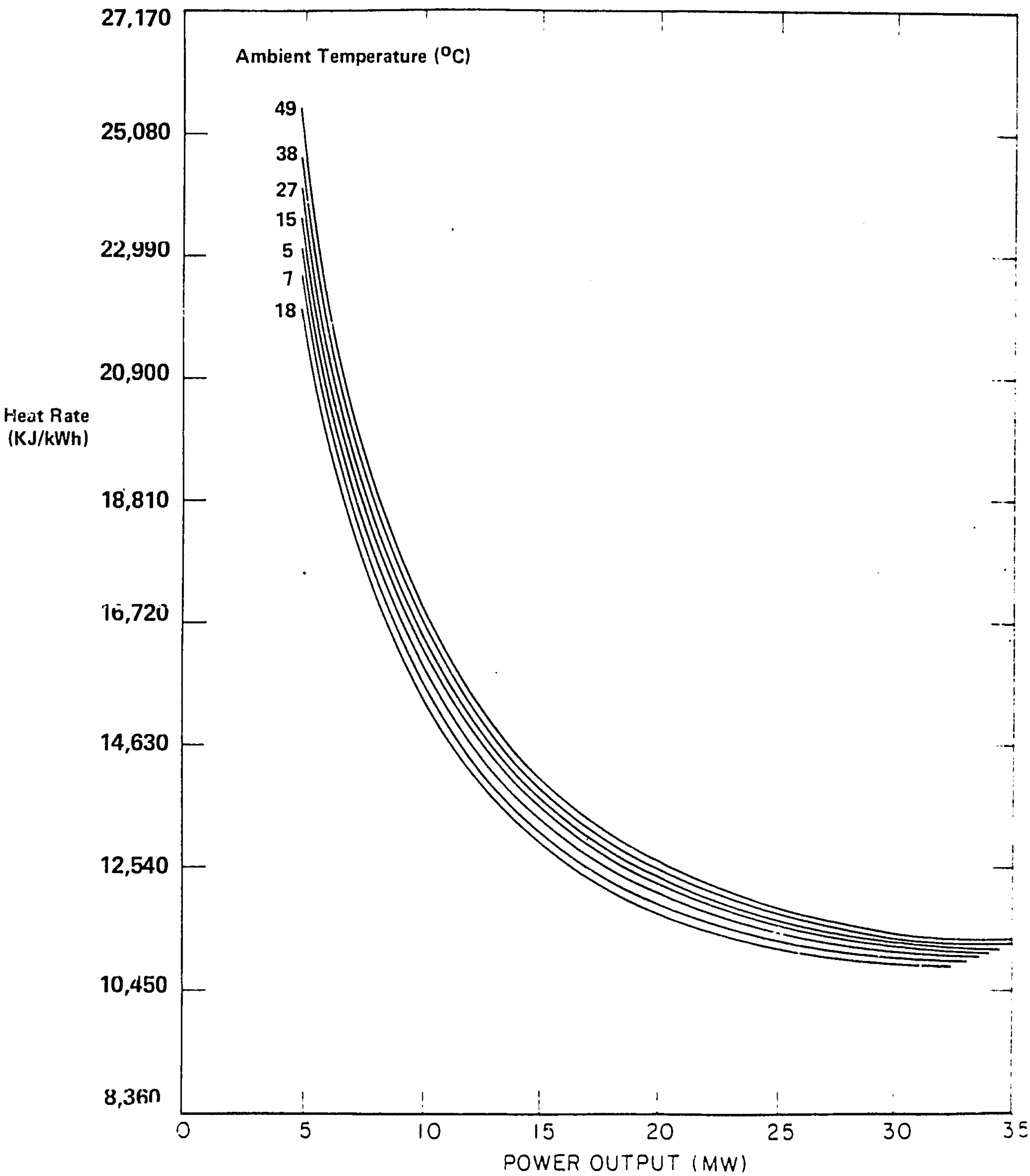
L.P. steam = Low-pressure steam



728 SOURCE: Hagler, Bailly & Company

Exhibit 19.8

Heat Rate Power Output and Ambient Temperature No Loss Conditions



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costs range from \$400/kW for a 100-MW system to about \$750/kW for a 10-MW system. At the smallest size, the cost approaches \$1,500/kW. Depending primarily on size and integration requirements into the industrial plant's processes, installation time can range from a few months to less than 2 years.

Gas turbines require more maintenance than do steam turbines. The combustion system must receive minor inspections, and mechanical parts must be inspected at intervals ranging from 5,000 to 10,000 hours, depending on the fuel used and the frequency of starting. Major overhauls are required at 20,000 to 75,000 hours. However, the gas turbine or its major modules can be replaced on-site without major disassembly.

Nonfuel operating and maintenance costs vary widely for gas turbine cogeneration systems. The most reliable operation (and therefore lowest maintenance costs) is obtained when natural gas is used as the fuel. In this instance, forced outages (i.e., equipment breakdowns) occur less than 1 percent of the operating hours, and scheduled outages (i.e., planned maintenance) occur 2 to 3 percent of the total operating hours. Units operating on oil require more frequent scheduled and unscheduled maintenance; for example, gas turbine cogeneration systems using No. 2 oil (i.e., distillate oil) require twice as much maintenance as a system using natural gas. Although a gas turbine cogeneration system is not as complex as a boiler/steam turbine system, additional skilled labor typically is required for both operation and maintenance beyond that already dedicated to operating and maintaining process boilers. These costs can be excessive when compared with the potential benefits from small gas turbine cogeneration systems.

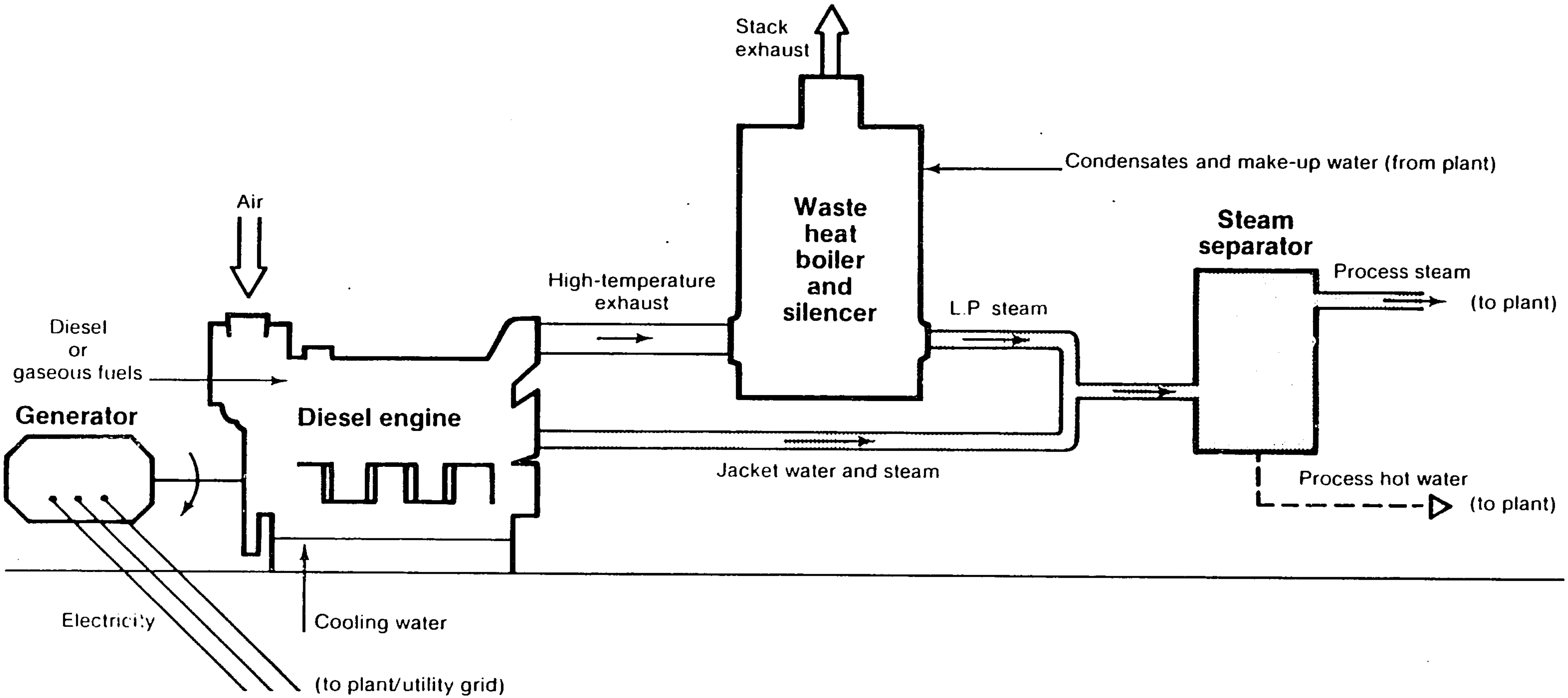
Reciprocating Engine Cogeneration Systems

A reciprocating engine burns oil or natural gas to generate mechanical shaft power for electricity if connected to an electrical generator. In a manner similar to the gas turbine, the combustion gases exhausted from the engine can be used to produce steam (or hot water) in a heat recovery boiler and direct heat (i.e., heated air or hot exhaust gases) for industrial process applications (see Exhibit 19.9 for a typical configuration). Unlike a gas turbine, steam (or hot water) can be produced by thermal energy recovered from the engine cooling system. For direct process heat applications, the engine exhaust (ranging up to 400°C) can either be used directly or through air-to-air heat exchangers.

Exhibit 19.9

Diesel Engine Cogeneration System

L.P. steam = Low-pressure steam



SOURCE: Hagler, Bailly & Company

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Reciprocating engines for cogeneration systems can be broadly classified in terms of engine speed in three categories: high-speed engines at 900-1,500 rpm, with unit sizes ranging from 100 kW to 3,500 kW; medium-speed engines at 500-600 rpm, with unit sizes ranging from 3,000 kW to 9,000 kW; and slow-speed engines at 90-150 rpm, with unit sizes ranging from 8,000 kW to 28,000 kW.

The type of fuel used in reciprocating engine cogeneration systems depends on the engine speed and, to some extent, on the engine design. As engine speeds are increased in diesel engines, higher grades of fuel oil generally must be used. Exhibit 19.10 illustrates typical limiting fuel-oil properties that apply to each of the engine categories. High-speed diesel engines almost always use No. 2 distillate fuel oil (high-grade residual fuel oil is generally either unavailable or equal in cost to distillate). Medium-speed diesel engines can use either residual oil or distillate oil. Slow-speed diesel engines almost always use residual fuel oil. High-speed and medium-speed reciprocating engines can use natural gas either as the only fuel or as one fuel in a dual-fuel engine.

The reciprocating engines used in industrial cogeneration systems typically have efficiencies ranging from 20 percent to almost 40 percent (see Exhibit 19.11). The efficiency of reciprocating engines depends primarily on fuel used and engine speed. High-speed reciprocating engines using natural gas generally have efficiencies between 20 percent and 30 percent. In contrast, the efficiency of slow-speed diesel engines using residual fuel oil approaches 45 percent.

In the predominant form of reciprocating engine cogeneration used in industry, only the engine exhaust gases are recovered for industrial steam and/or direct heat applications. The temperature of the exhaust gases released by reciprocating engines is generally lower than that of gas turbines, typically operating between 250°C and 475°C. For this reason, the pressure of the steam generated in heat recovery boilers is generally lower than 30 bar. In slow-speed reciprocating engines where exhaust gas temperatures are lower than 325°C, the steam pressures are usually less than 15 bar. In a manner equivalent to that described for gas turbine cogeneration systems, using fuel to directly heat the engine exhaust (or the heat recovery boiler) will allow high-temperature direct heat (or higher-pressure steam) and greater mass flow to be produced.

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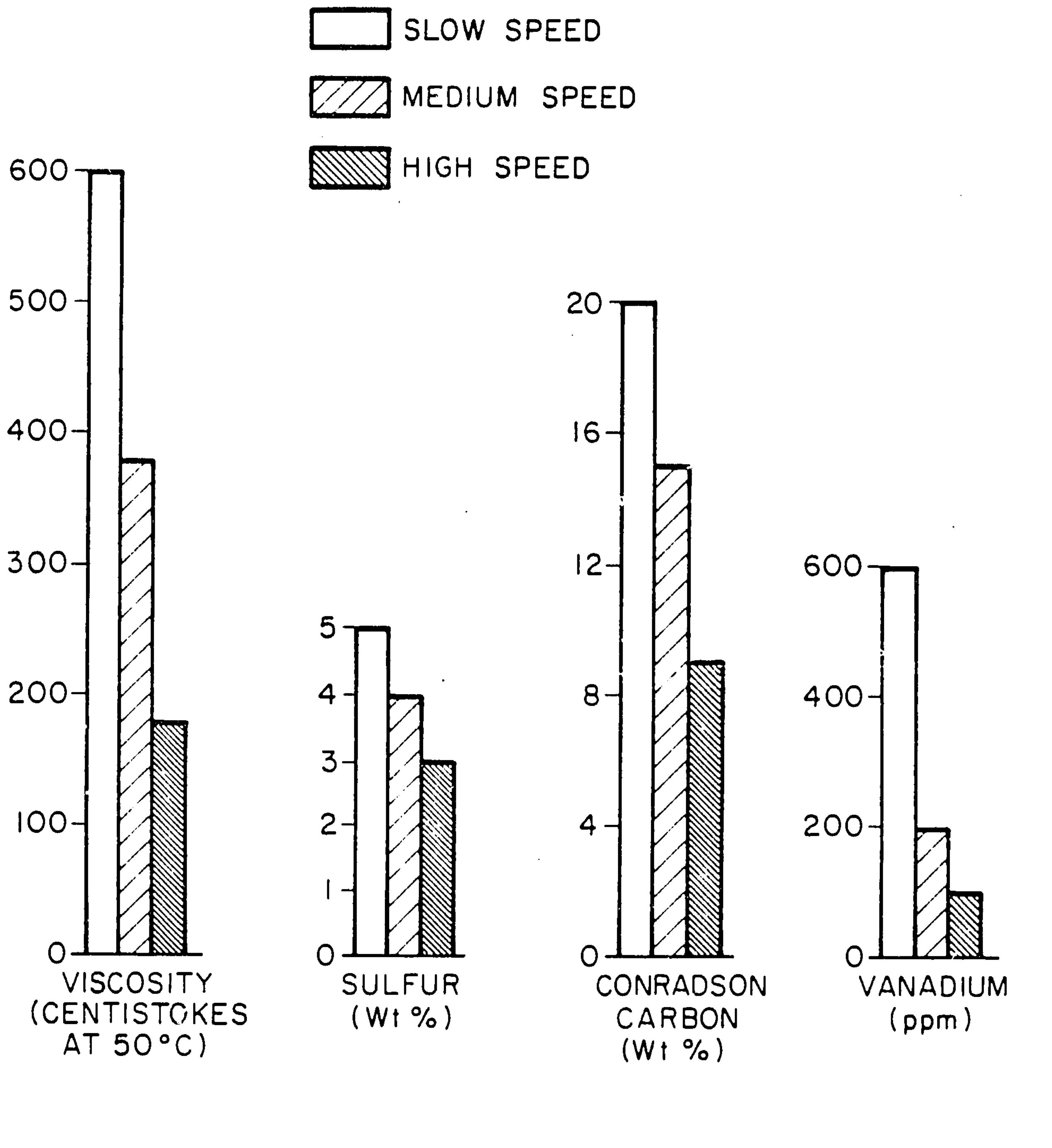
Exhibit 19.10
Typical Limiting Fuel Oil Characteristics for Reciprocating Engines



SOURCE: Hagler, Bailly & Company

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Exhibit 19.11

Typical Full Load[1] Energy Balance for Representative Reciprocating Engines as Fraction of Input

	Slow speed	Medium speed	High speed
Input (LHV)[2]	100	100	100
Power	41.3	38.0	32.8
Exhaust gases	32.2	33.7	30.5
Cooling system[3]	24.5	25.0	31.9
Radiation, other losses	2.0	3.3	4.8

[1]Energy balance changes with load.
[2]Lower heating value.
[3]Includes lube oil, cylinder, and charge air cooler.

In addition to releasing their heat exhaust gases, reciprocating engines reject a substantial amount of low-temperature heat in their cooling systems: oil cooling and water jacket cooling. Oil cooling is the lowest grade of recoverable heat, with maximum temperature levels approaching 80°C. Water jacket cooling systems on some engine designs can be operated at 20 bar pressure levels to produce low-grade steam at 120°C in an ebullient cooling mode.

Because of the widely varying configurations (i.e., use of cooling system heat and supplemental boiler fuel), reciprocating engine cogeneration systems can produce a broad range of power-to-heat ratios. With unfired heat recovery boilers, the power-to-heat ratio varies between 0.85 GJ/GJ and 1.70 GJ/GJ, depending on the recovery of heat available in the cooling system. When steam only is generated, the power-to-heat ratio increases to between 1.50 GJ/GJ and 5.00 GJ/GJ. With either supplementally- or fully-fired heat recovery boilers, the power-to-heat ratio can be as low as 0.44 GJ/GJ.

Although the efficiency of the reciprocating engine cogeneration system varies with the engine design (e.g., slow-speed), the fuel used (e.g., natural gas) and system configuration (e.g., recovery of heat from cooling system), the engine efficiency will change under part load and changing ambient temperature (see Exhibit 19.12). However, these effects are much less significant than those incurred for gas turbines.

For the same reasons as those cited for gas turbine cogeneration systems, the capital costs of reciprocating engine cogeneration systems will depend primarily on size. For small reciprocating engine cogeneration systems (i.e., 1,000 kW and smaller), the total capital costs approach $2,000/kW, the upper limit representing systems using both heat recovery boilers and cooling-system heat recovery. For large systems (i.e., over 15 MW), the costs are close to $400/kW. Depending primarily on size and requirements for system integration into the industrial plant's processes, installation time can range from a few months to almost 2 years.

Of the three types of cogeneration systems addressed, reciprocating engine systems require the most maintenance. Although the reliability and service life of reciprocating engines are high, they typically require minor inspections and maintenance at 7,000-

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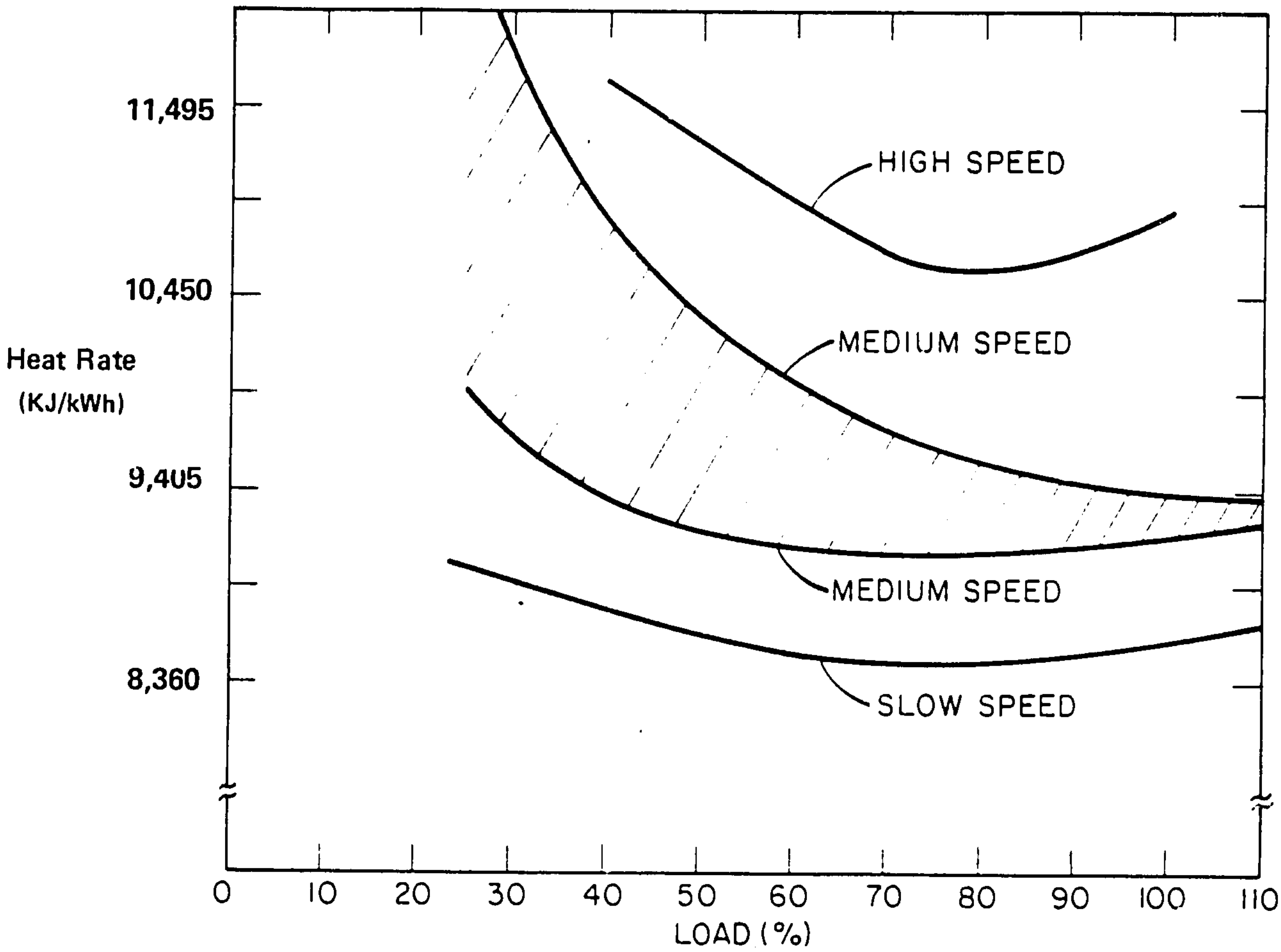
Exhibit 19.12
Typical Variation of Reciprocating Engine
Heat Rate with Load



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to 10,000-hour intervals and major overhauls every 20,000-30,000 hours. As a rule, engines using natural gas require less service than those using fuel oil. However, the reciprocating engine and its ancillary equipment can be replaced on-site without major system disassembly. For the same reasons as those cited for gas turbines, forced outages and scheduled maintenance for reciprocating engine cogeneration systems using natural gas are less frequent than those for systems using fuel oil. However, the total hours for forced and scheduled outages of a reciprocating engine represent 2-3 times the amount of time for a gas turbine using the same fuel. For this reason, standby reciprocating engines are sometimes required.

Because a reciprocating engine is the simplest of the three cogeneration systems to operate, the requirement for additional operating labor may be less than that for gas turbine and boiler/steam turbine cogeneration systems. However, at a minimum, skilled labor will be required for maintenance. For small system sizes, this additional cost may be excessive when compared with the potential benefits.

Bottoming-Cycle Systems

In a **bottoming-cycle system**, thermal energy exhausted in the industrial process is recovered for the production of electrical or mechanical energy (see Exhibit 19.13 for a typical configuration). In a bottoming-cycle system, fuel is first consumed by high-temperature processes and energy is extracted from the rejected heat to drive a turbine that produces mechanical power (or electricity, if an electrical generator is used). In this manner, power can be generated without requiring additional fuel. In this type of system, a liquid working fluid is heated and vaporized by rejected process heat; the hot vapor passing through a turbine produces electric or mechanical power. The turbine exhaust is typically condensed, but may be used in industrial process applications.

There are basically two categories of bottoming-cycle cogeneration systems used in industrial applications: steam bottoming systems and organic-fluid bottoming system. In a steam bottoming system, heat from the exhaust gases is used to produce steam in a recovery boiler. The steam is then expanded in a turbine to generate power. In an organic-fluid bottoming system, organic fluids with low heats of vaporization are used in place of steam.

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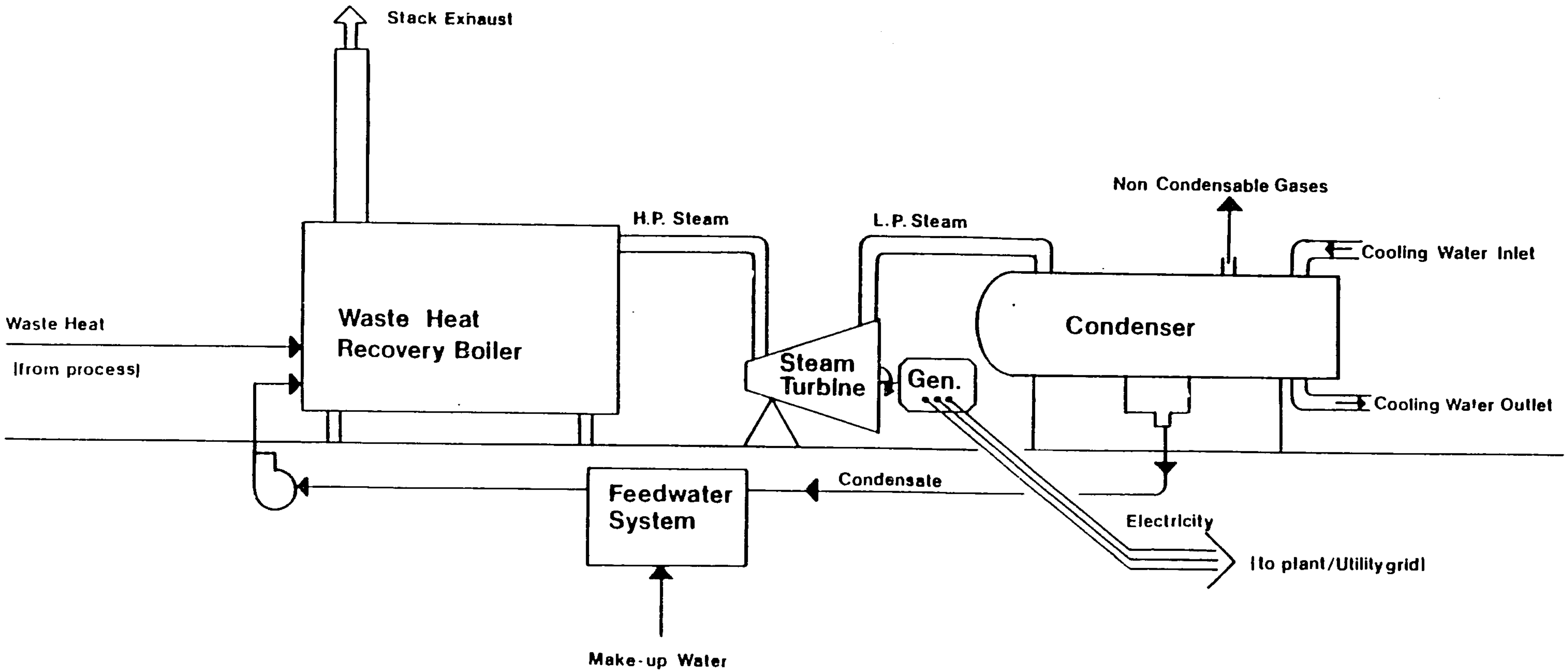
Exhibit 19.13
Waste Heat Recovery Boiler/Condensing Steam Turbine



SOURCE: Hagler, Bailly & Company

Steam Bottoming Systems

The boiler in a steam bottoming system, which generates steam through the recovery of heat rejected by an industrial process, is a power boiler in that it has the capability of producing steam of sufficient pressure and temperature to drive a steam turbine. As cited previously for boiler/steam turbine topping-cycle systems, the steam produced can range from about 25 bar saturated steam to 100 bar superheated steam. Boiler efficiencies depend on a number of factors, including the temperature and mass flow of the rejected heat and the configuration of the boiler in relationship to the rejected heat, but typically range between 85 and 95 percent. The temperature range of the rejected heat most commonly used in steam bottoming systems is between 150°C and 600°C.

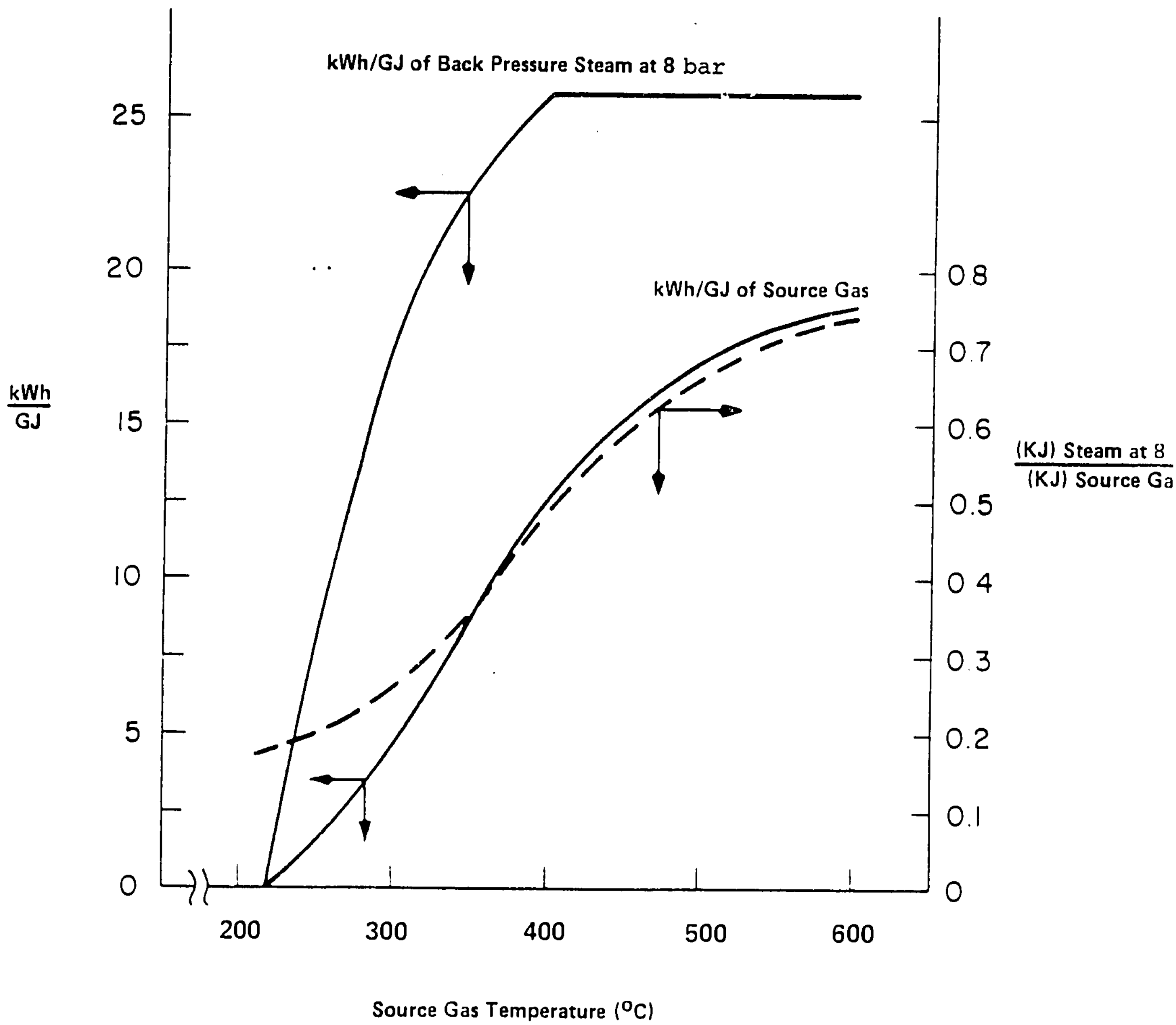
Several steam turbine configurations can be used in a steam bottoming system. The turbine can be a straight backpressure or extraction/condensing turbine delivering steam for process use in addition to generating power. Also, the turbine can be a condensing turbine generating power without producing process steam. With the backpressure and extraction/condensing steam turbines described previously, system efficiencies range from less than 20 percent to more than 70 percent (see Exhibit 19.14). With condensing steam turbines, the system efficiencies range from less than 5 percent to approximately 20 percent (see Exhibit 19.15).

As in the case of gas turbine and reciprocating engine topping-cycle cogeneration systems, the heat recovery boilers in the steam bottoming systems can be fuel-fired to increase the amount and pressure of steam produced. In the extreme where the heat recovery boiler is fully fuel-fired, the exhaust heat recovered from the industrial process could possibly make a minimal contribution to steam production.

Because the boilers used to recover the rejected heat exhausted by the industrial process are designed specifically to meet site requirements, the total capital costs of steam bottoming systems vary widely. However, typical costs appear to range between $1,200/kW for large (sizes exceeding 10 MW) systems and $2,000/kW for small (sizes up to 500 kW) consisting principally of standard "off-the-shelf" equipment. The amount of time required for installation depends primarily on the fabrication and installation of the heat recovery boiler, ranging from 1 to 3 years.

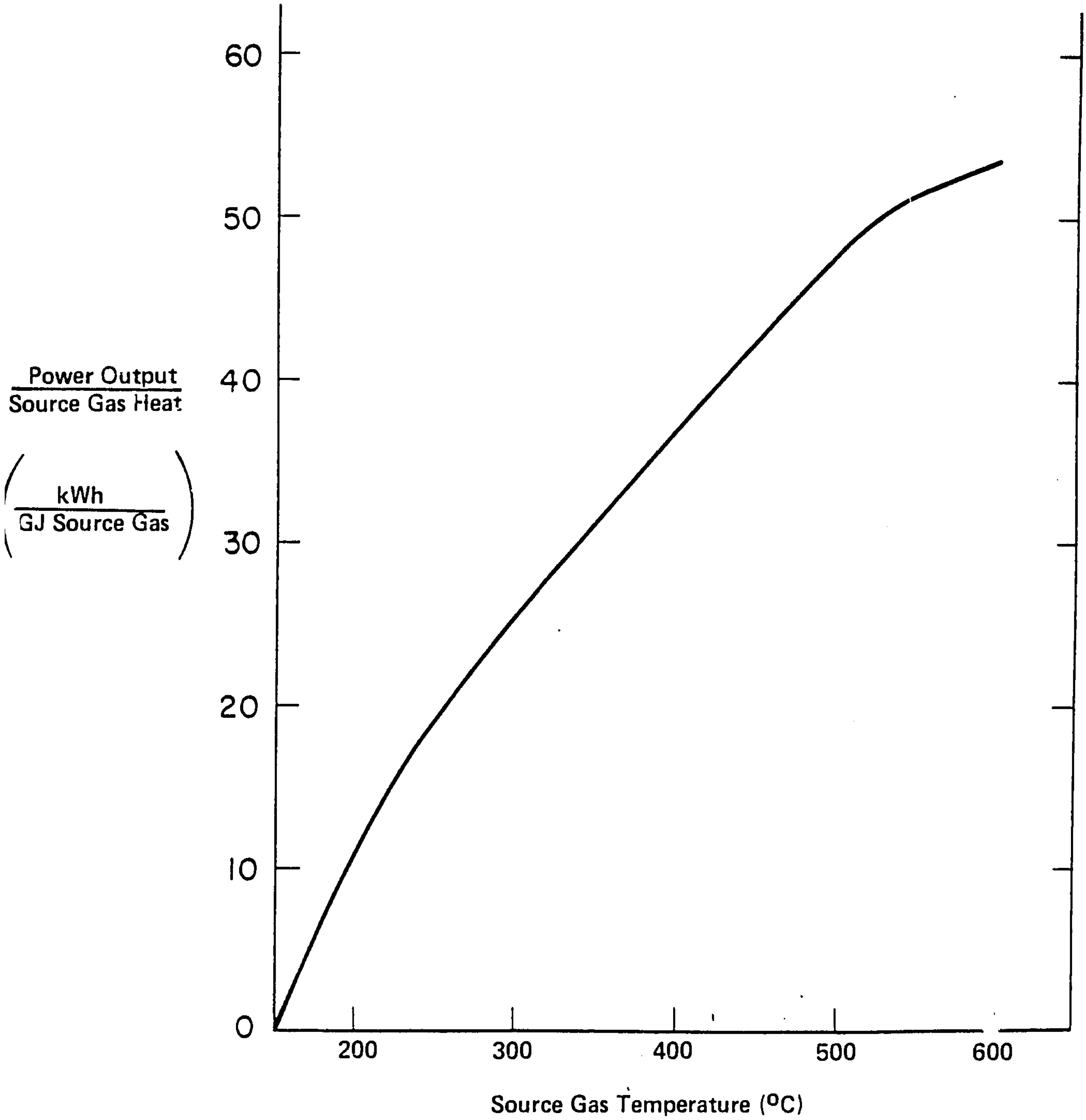
Exhibit 19.14

Power and Steam Generation by Noncondensing Steam Turbine Bottoming of Waste Heat



SOURCE: Hagler, Bailly & Company

Exhibit 19.15
Power Generation by Condensing Steam Rankine Bottoming of Waste Heat



Because steam turbines require little maintenance (see previous sections), the heat recovery boiler will be the dominant factor in determining the operation and maintenance costs. The temperature and cleanliness of the industrial process exhaust heat will dictate the maintenance schedule and ultimately the service life of the heat recovery boiler. However, other site-specific factors such as additional labor requirements may determine the overall operating and maintenance costs.

Organic-Fluid Bottoming Systems

The organic-fluid bottoming system operates on the same principles as the condensing steam bottoming system and, depending on the organic fluid used, may produce more or less power than steam systems. A variety of such fluids are currently in use or being tested: toluene, butane, pentane, Fluorinal, Dowtherm-A^R, monochlorobenzene, and a variety of fluorocarbons, particularly Freons R11, R22, R113, R114, and C318.

The maximum amount of power that can be generated with these fluids is shown as a function of process exhaust gas flow and temperature in Exhibits 19.16 and 19.17. The discontinuities in some of the curves in these exhibits are caused by the fact that, at low source gas (i.e., process exhaust) temperatures, the limiting temperature difference for organic fluids occurs at the inlet of the heat recovery boiler and not at the point of liquid saturation.

The two major advantages of most organic fluids over steam is that these fluids can recover energy at process exhaust temperatures below those for steam, and organic-fluid systems have higher efficiencies than steam bottoming systems at low process exhaust temperatures. For instance, systems using Freon 11 can operate at process exhaust temperatures as low as 100°C, which is almost 100°C lower than the lower limit for condensing steam bottoming systems. At a source gas temperature of 200°C, an organic-fluid bottoming systems using toluene has an efficiency of 10-15 percent, which is about three times that of a condensing steam bottoming system.

The major disadvantages of organic-fluid bottoming systems relate to the organic fluids. All organic fluids have corrosive properties and are volatile and flammable above certain temperatures.

Exhibit 19.16

Power Generation Using Organic Fluids in Condensing Systems

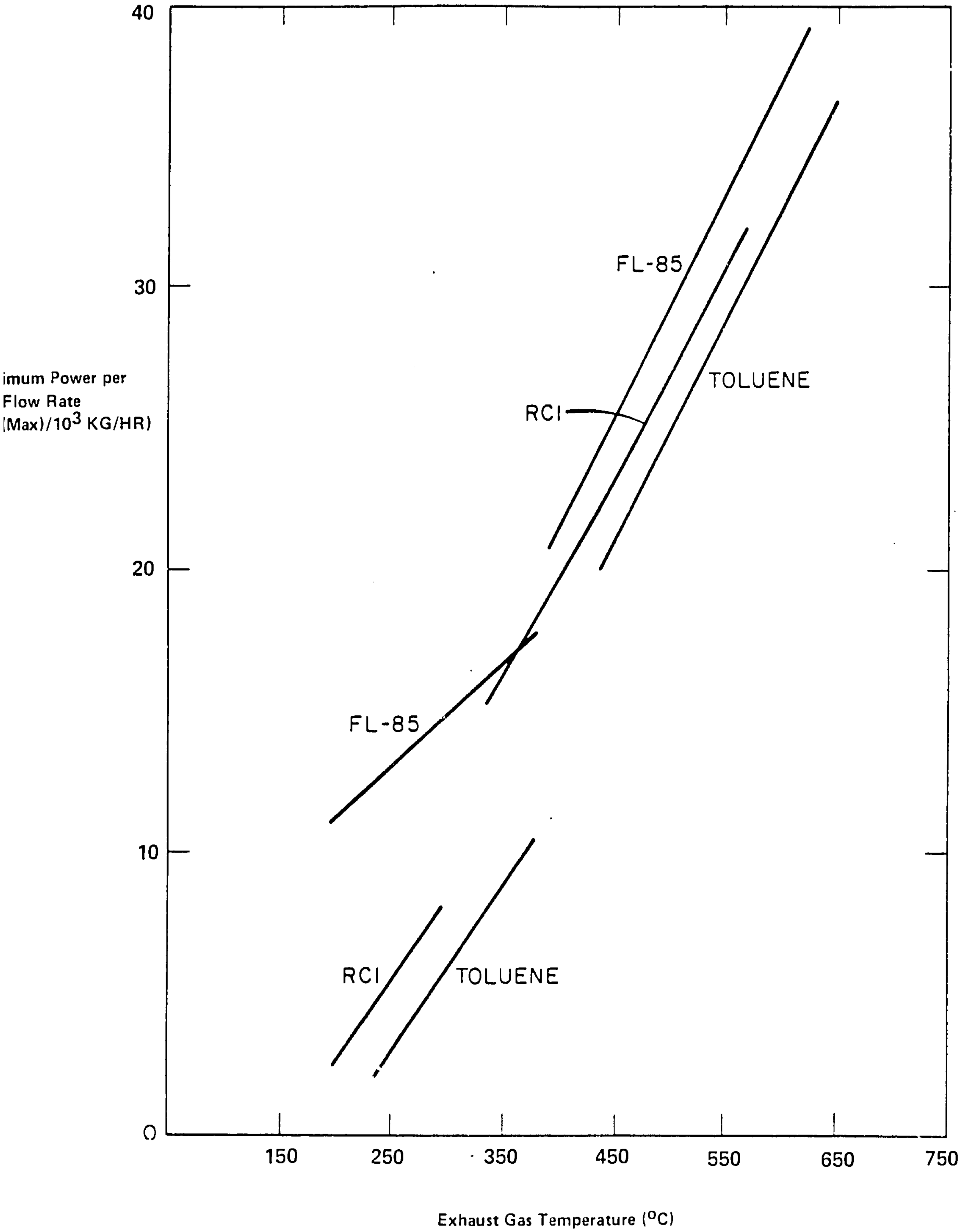


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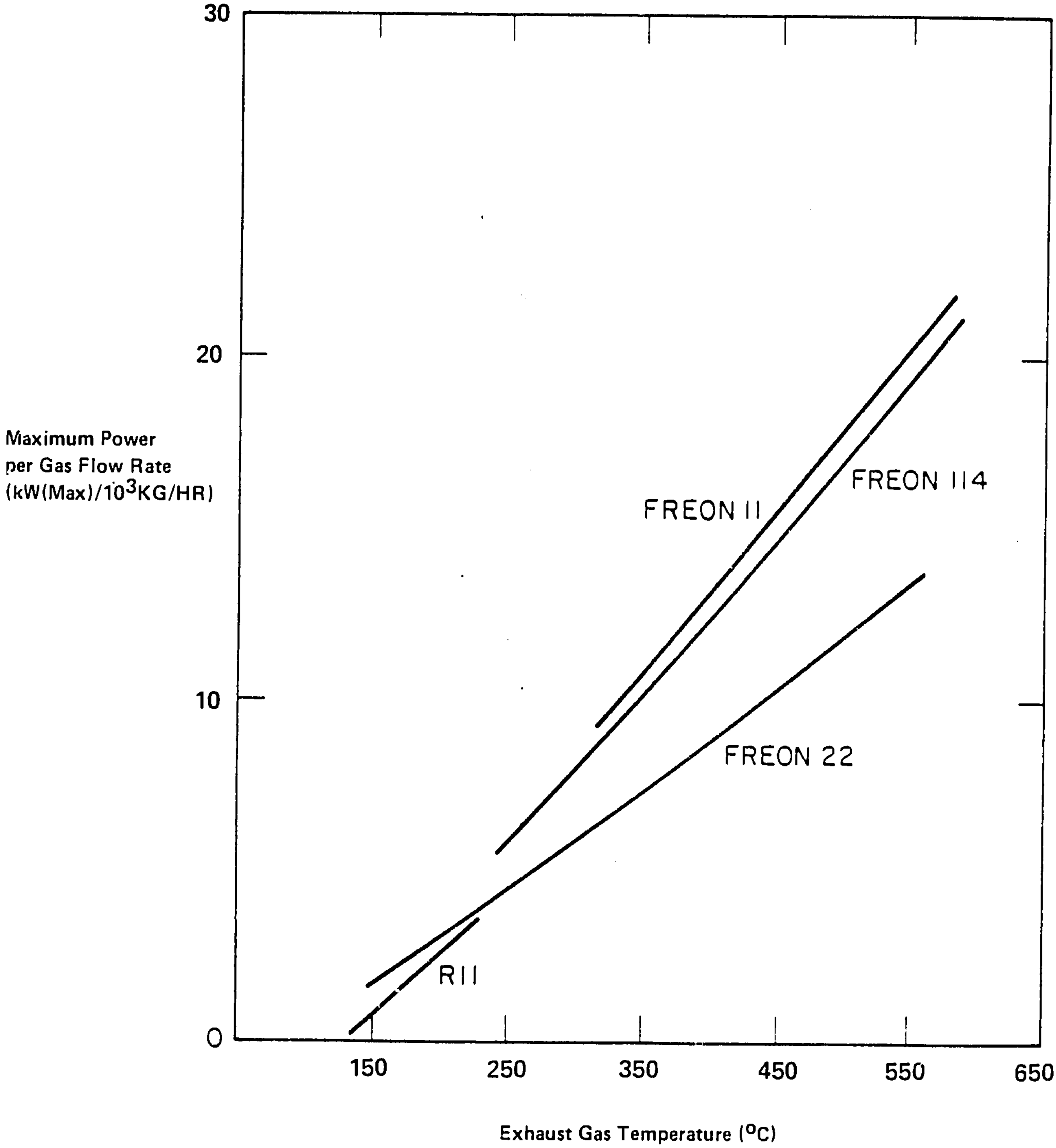
Exhibit 19.17
Power Generation Using Organic Fluids in Condensing Systems



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Bottoming systems using organic fluids have capital costs approaching and sometimes exceeding those of steam bottoming systems, typically ranging from \$1,700/kW to \$2,500/kW. Organic-fluid bottoming systems are commercially available but are generally custom-designed for most applications recovering exhaust process heat. The amount of time required for installation is generally equivalent to that incurred for steam bottoming systems.

Because these systems use organic fluids, the operating and maintenance costs are typically greater than those incurred for steam bottoming systems. The cost of procuring and handling organic fluids is obviously greater than that of water. In addition, using these fluids may require labor that is especially skilled in the operation and maintenance of these systems. These costs may be excessive when compared with the potential benefits.

SMALL POWER GENERATION

Small power generation has traditionally been associated with emergency and standby electricity generation used primarily during periods of interruptions in electric utility service. The most prevalent form of on-site standby electrical generation is reciprocating engines using fuel oil (i.e., diesel engine/generator sets).

However, small power generation for industrial applications can represent something other than on-site standby electrical generators. In the broadest terms, small power generation denotes any on-site continuous, cycling, and standby production of power. The remainder of this session will focus on small power generation for continuous and cycling operation consisting of widely-used and proven technologies and systems.

Technically, there are two fundamental types of small power systems, differentiated on the basis of whether fuel is burned or not. Fuel-fired small power systems addressed in this session are boiler/condensing steam turbine, gas turbine, and reciprocating engine systems.

Boiler/Condensing Steam Turbine Systems

Unlike cogeneration, steam is not exhausted or extracted for process applications. In small power applications, high-pressure steam produced in a direct-fired power boiler flows through a steam turbine and is condensed in a liquid-to-air (or liquid-to-liquid) heat exchanger. Condensing steam turbines are designed to maximize the extraction of energy contained in the steam for generating power. As a consequence, the steam emerging from the turbine is at or below atmospheric pressure. Once the steam is condensed, the condensate is pumped back to the power boiler. In small power applications, condensing steam turbines generally have power generation efficiencies of between 15 and 40 percent.

Depending on the fuel used, total system efficiencies can range from less than 10 percent to about 35 percent. The lower end of the range is representative of small systems (i.e., less than 500 kW) using waste fuels with high moisture content (i.e., approaching 60 percent by weight).

As in the case of boiler/steam turbine cogeneration systems, the boiler(s) and its ancillary equipment represent the most expensive equipment in a boiler/steam turbine power plant, ranging from 50 percent to 80 percent of total cost (depending on system design and fuel cost). Overall, the total installed cost (1982 dollars) ranges from $1,000/kW (approximately 20 MW and greater) for an oil-fired boiler/steam turbine system to almost $3,000/kW for a small (less than 2 MW) coal- or waste-fired boiler/steam turbine system. Installation can range from less than a year to almost 3 years, depending on size and fuel used.

The cost of spare parts and expendables will be the largest component of nonfuel operating and maintenance cost. Up to three additional skilled laborers per plant shift may be required to operate and maintain this system.

Condensing steam turbine technology has been demonstrated worldwide. Manufacturers usually recommend minor annual inspections and major inspections every 3 years. Replacement parts are readily available, and maintenance schedules can be typically coordinated with operating schedules of the plant.

Gas Turbine Power Systems

Unlike a gas turbine cogeneration system, where energy is recovered from the exhaust gases to produce steam, the energy can be recovered in a recuperator to preheat the combustion air before it is mixed with fuel and burned. This can improve the efficiency of a gas turbine up to 40 percent for small gas turbines (less than 2 MW). Typically, gas turbines for small power applications have efficiencies ranging from about 15 percent to approximately 30 percent (without recuperators) and 20 percent to almost 40 percent (with recuperators). A regenerator (or recuperator) is nothing more than an extended-surface, counterflow, one-pass heat exchanger that transfers exhaust heat to the compressed air before it enters the combustor (see Exhibit 19.18). Its purpose is to reduce the amount of fuel needed to heat the air to combustion temperature. Since it frees more fuel for combustion, a regenerator can cut fuel consumption dramatically.

There are two basic types of industrial gas turbines: aircraft-derivative and heavy-duty. Aircraft-derivative types are lightweight units modeled after familiar jet engines, while heavy-duty machines combine the rugged mechanical construction of utility-size gas turbines with the light weight and compactness of aeroderivative combustion turbines.

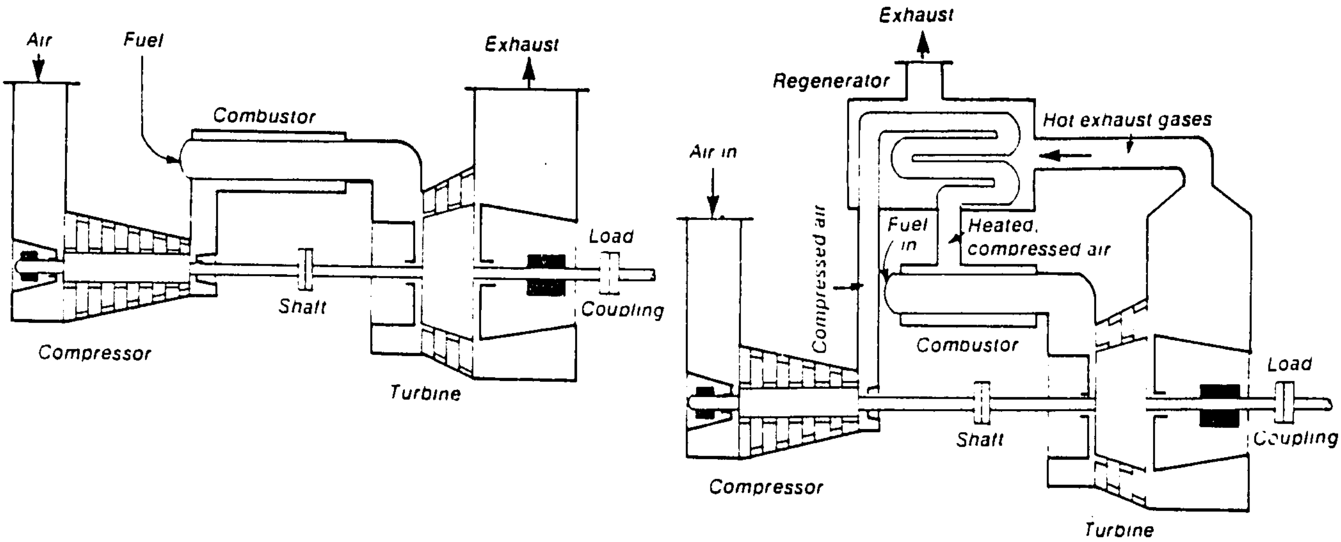
Gas turbines are available as one- or two-shaft models. In a single-shaft configuration, typically used to drive a generator, the turbine is built on one continuous shaft; therefore, all stages operate at the same speed. On two-shaft machines, on the other hand, the low-pressure turbine rotor is completely separated mechanically from the high-pressure turbine and compressor rotor. This allows the low-pressure turbine to operate over a wide range of speeds and makes two-shaft combustion turbines ideally suited to variable-speed (mechanical-drive) industrial applications.

Although capital costs will depend on fuel used, size, and type of duty (i.e., standby and continuous duty cycle), capital costs range from $200/kW for large systems (exceeding 10 MW) to more than $800/kW for very small systems (less than 100 kW). Because of the simplicity of this system relative to a gas turbine cogeneration system, installation time is generally less, and normally should be 1 year or less.

Although combustion turbines require more maintenance than do steam turbines, the lack of a heat recovery system results in less maintenance than for combustion turbine

Exhibit 19.18

Combustion Turbine Power System (without and with recuperator)



SOURCE: Hagler, Bailly & Company

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cogeneration systems. The maximum maintenance is generally required for a combustion turbine using a low-grade oil and operating on a continuous duty cycle. However, because of frequent start-ups, a combustion turbine operating on intermittent duty will require almost twice as many inspections as a combustion turbine operating on continuous duty for the same number of operating hours.

To minimize the requirements for skilled labor for day-to-day operation, control devices are available that allow automatic start-up, operation, and shutdown with limited monitoring. Units driving generators can have systems that automatically regulate speed and voltage. They synchronize the unit to the line before closing the switch and bringing load up to a predetermined level. In many instances, current employees can be trained to perform operating and monitoring duties. However, in the case of large combustion turbines (exceeding 10 MW), additional skilled labor will likely be required.

Reciprocating Engine Power Systems

In contrast with engines in which fuel and air mix before compression are those engines in which only air is compressed and fuel enters near the end of compression (see Exhibit 19.19). In the diesel engine, a prime example of this class, heat of compression is used to ignite the fuel.

In a typical diesel, air is compressed to about 30 bar, which brings it up to about 500°C. When finely atomized oil is sprayed into this "red-hot" air, it ignites and burns. Thus, in the diesel, the high compression ratio necessary for reliable ignition means inherently high efficiency.

Regardless of the category of the reciprocating engine (i.e., high-speed, medium-speed, and slow-speed), the overall efficiency of the engine is improved with the use of a supercharger. In simplest terms, the chief purpose of supercharging is to cram more air into the cylinder so more fuel can be burned and engine output increased. It is accomplished by supplying intake air at a density above atmospheric pressure and retaining this increased density in the cylinders at the start of the compression stroke.

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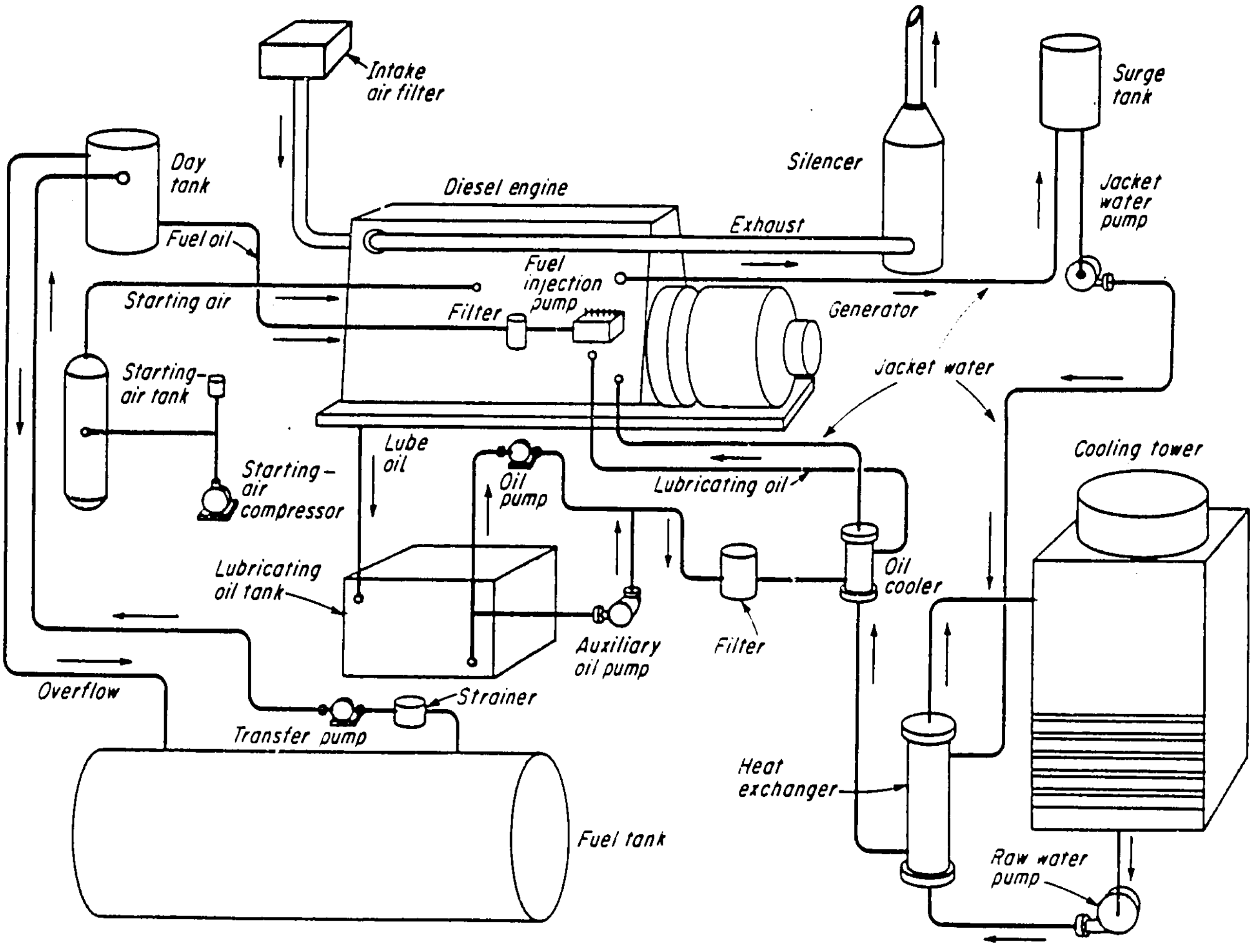
19.19

Oil-Fired Reciprocating Engine Power System (diesel engine)



SOURCE: Hagler, Bailly & Company

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Diesel engines used in industrial power systems typically have efficiencies ranging from 20 percent to almost 40 percent without recuperation of waste heat. With a supercharger, the engine power generation efficiency can be increased by up to 15 percent.

Although costs will depend primarily on size and engine-speed category, the total installed costs for reciprocating engines will range from $200/kW for large slow-speed engines to more than $800/kW for small high-speed engines. Due to the lack of process integration requirements necessary for a reciprocating engine cogeneration system, reciprocating engine power system installation period can range from a month to a year.

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SESSION 20: ELECTRICITY USE, PART 1 — ENERGY PERFORMANCE OF VARIOUS TYPES OF EQUIPMENT

INTRODUCTION

Electricity plays a very important role in the operation of any industrial facility, powering lights, motors, instrumentation, and process equipment. The major attraction of electricity as an energy source is its ease of use when compared with other energy sources such as fuel oil or solid fuels.

Historically, efforts to improve plant efficiency have been aimed at the more obvious sources of energy waste (e.g., combustion systems, space conditioning, process areas), while the conservation of electricity has generally been overlooked or given a low priority in favor of areas where savings could be achieved more readily. This approach to conservation is shortsighted when even the most superficial analysis of industrial or commercial energy use patterns show that electricity is a major contributor to any facility's total energy bill. Exhibit 20.1 shows the distribution of energy by type and cost for a typical manufacturing facility. Examination of the two pie charts shows that relatively small savings in electrical energy can reap significant financial savings. Accordingly, the emphasis of this session will be to discuss the operating principles of some of the more common equipment that consumes electricity and how it can be made more efficient. It is worth noting at this time that the one cardinal rule for conserving electricity -- as with any other energy source -- is:

WHEN YOU DON'T NEED IT — TURN IT OFF.

The main industrial users of energy are ac motors and lighting, and these are discussed together with other common users.

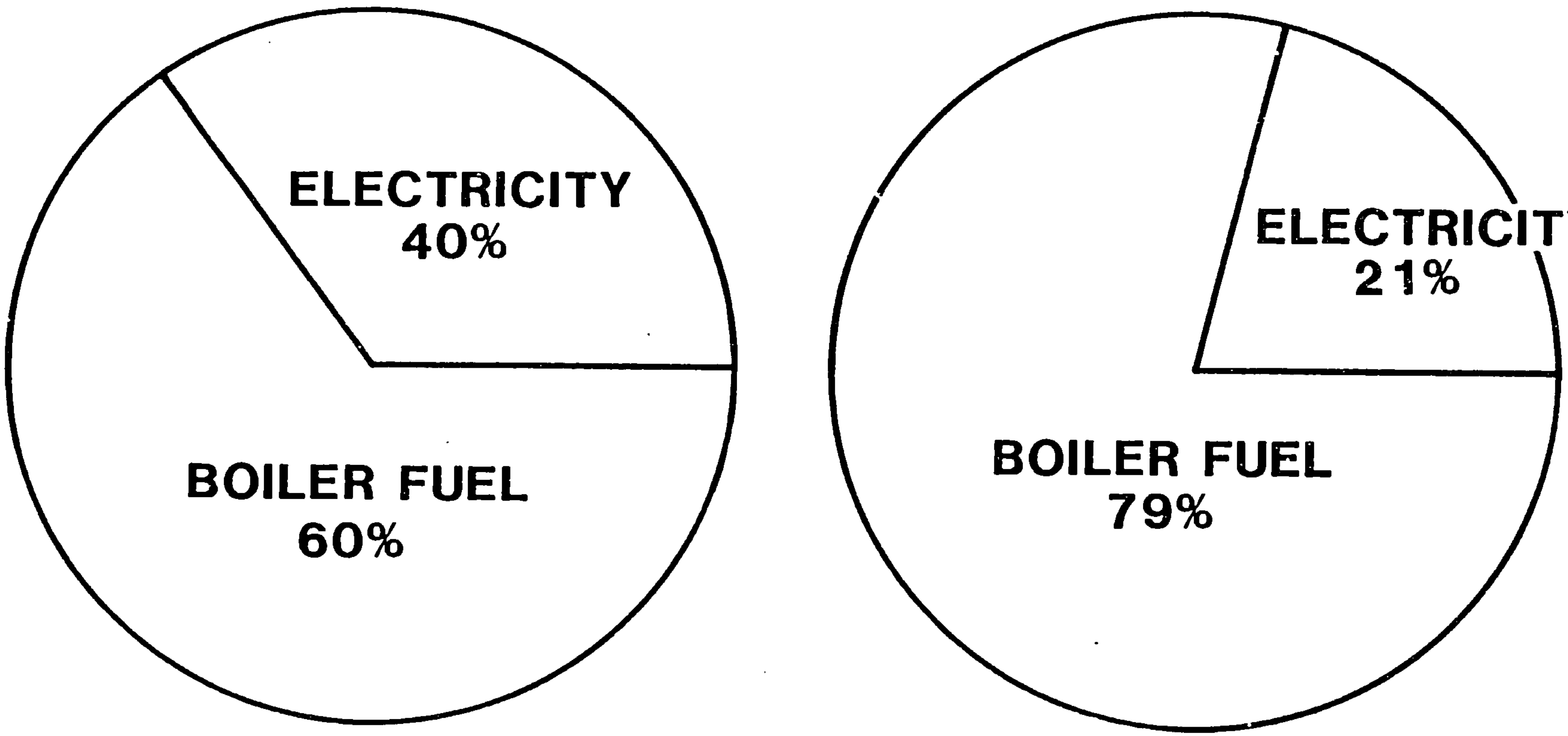
MOTORS

In any modern manufacturing facility, electric motors are the single largest consumer of electrical energy and deserve particular attention in their selection, operation, and

Exhibit 20.1

ENERGY DISTRIBUTION

BY COST　　　　　　BY TYPE



TYPICAL MANUFACTURING FACILITY ENERGY DISTRIBUTION
BY COST AND TYPE OF ENERGY CONSUMED

maintenance. Observation of proper practice will go a long way toward ensuring an energy-efficient operation.

Fundamentals of motor selection and maintenance are presented, with the aim of improving reliability and operating efficiency. In addition, concepts of some of the currently available motor control systems are introduced. It is not possible in a single session to cover fundamentals of operation of all the various types of motors and controllers available; that is more properly the subject of a separate seminar. The following are discussed:

- Operation
- Maintenance
- Energy conservation opportunities.

Motor Operation

Care should be taken to operate the motors in accordance with restrictions on the nameplate. Information provided defines safe operating limits of the motors, both from an environmental point of view and from that of motor operation. The primary purpose in placing a nameplate on a motor is to convey sufficient information to the user to ensure that the motor will be operated in accordance with design criteria. In general, criteria used by reputable motor manufacturers are based on standard industrial practice and established safety standards.

Satisfactory performance of most motors can be achieved when motors are operated within the normal line of variations of plus or minus 10 percent of nameplate voltage and 5 percent of nameplate frequency. Exhibit 20.2 shows which operating characteristics are affected adversely by variations from nameplate ratings. The following list of "don'ts" should be strictly observed for all types of motors. Failure to operate a motor as designed will seriously shorten motor life and can create safety problems.

- Don't operate motors at other than plus or minus 10 percent of nameplate voltage. Higher voltages adversely affect motor temperature, speed, and vibration, and can affect voltage-sensitive motor control relays. Lower

EFFECT ON MOTOR OPERATION OF VARIATION FROM NAMEPLATE SPECIFICATIONS

	PERFORMANCE PARAMETERS ADVERSELY AFFECTED BY NAMEPLATE DEVIATIONS									
						STARTING DEVICES				
NAMEPLATE PARAMETERS	TORQUE	SPEED	TEMPERATURE	NOISE	VIBRATION	THERMAL O/L PROTECTORS	CURRENT SENSITIVE	CENTRIFUGAL CUT-OUTS	CAPACITOR LIFE	MOTOR LIFE
(1) VOLTAGE	X	X	X	X	X	X	X		X	X
(2) FREQUENCY	X	X	X	X	X	X	X	X	X	X
(3) TORQUE (HP, RPM)	X	X	X	X	X	X	X			X
(4) TEMPERATURE RISE	X	X	X			X	X			X
(5) CAPACITOR	X	X	X	X	X	X			X	X
(6) DUTY			X			X	X	X	X	X

voltages can cause motor overload when starting and result in nuisance trips of thermal overload protective equipment.

- Don't operate motors on nominal frequencies other than those specified on the nameplate.
- Don't load motors in excess of nameplate ratings.
- Don't exceed nameplate temperature rise.
- Don't subject the motor to duty cycles for which it was not intended. "Continues" ("Cont") or "intermittent" ("Int") as stamped on the motor nameplate indicates the operating cycle for which the motor was intended and is generally based on the insulation class of the motor and the watts that the motor must dissipate when energized. Operating a motor at a different duty than specified will generally result in higher operating temperatures, shortening of motor life, and nuisance operation of thermal overload protection devices.

Motor Maintenance

The function of an electric motor is to provide motive power to a variety of equipment that performs useful work. Equipment driven by electric motors includes air compressors, pumps, refrigeration equipment, and fans. There are many other types of equipment dependent on electric motors for motive power. Because so much equipment is dependent on the proper operation of electric motors, it is essential that they be operated and maintained in a manner to ensure reliable and efficient operation.

Exhibit 20.3 shows the losses of a typical motor. Without proper maintenance, these losses can be much higher. Improper lubrication can cause increased friction in both motors and associated drive transmission equipment. Since electrical resistance in conductors increases with temperature, resistive losses within the motor will increase if ventilation ports or cooling systems are obstructed or dirty. Dust and lint should be removed regularly from motor openings to allow motors to run as cool as possible. Since increasing temperature also shortens insulation life, keeping motors cool will not only save energy but increase motor life.

Exhibit 20.3

TYPICAL MOTOR LOSSES

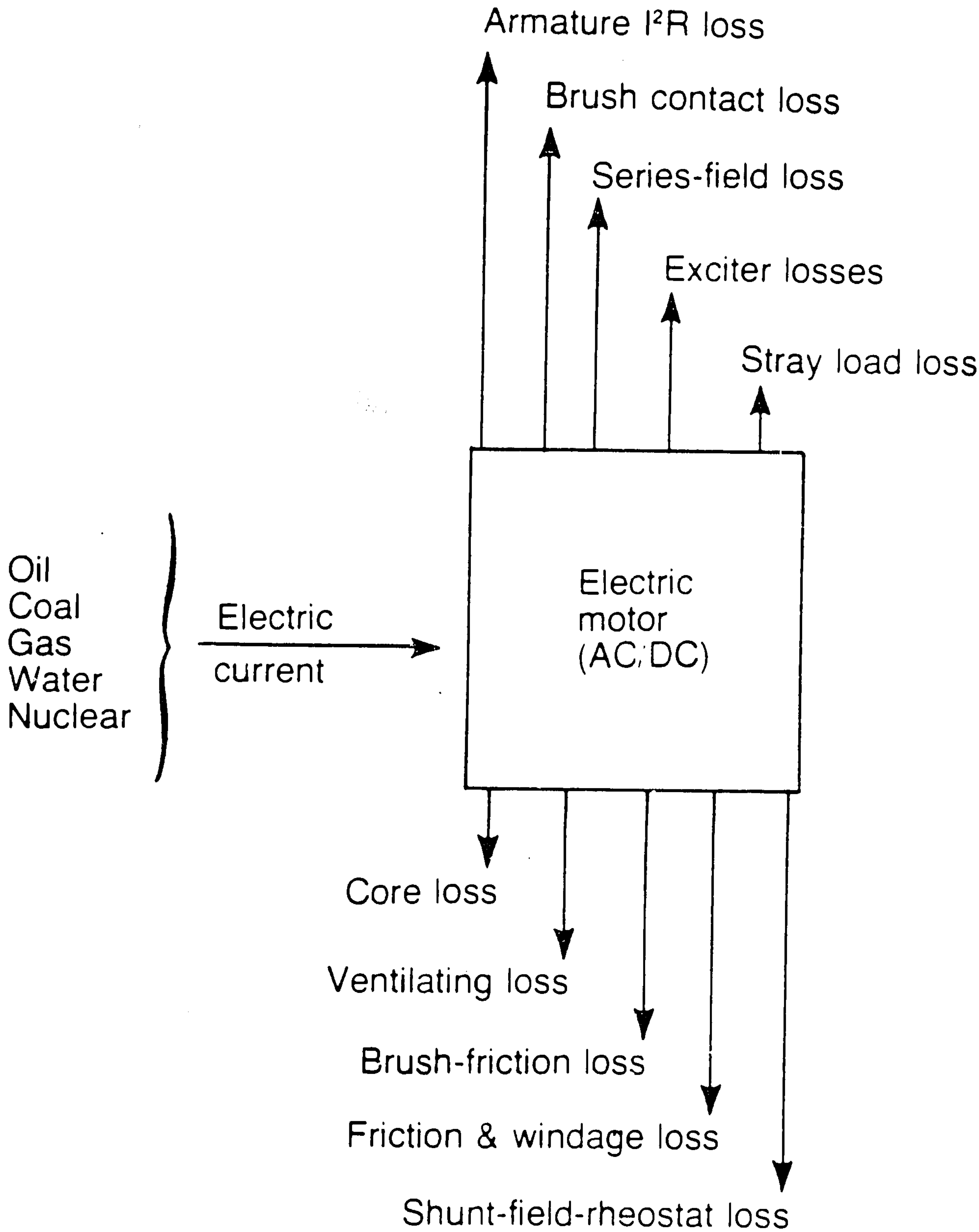


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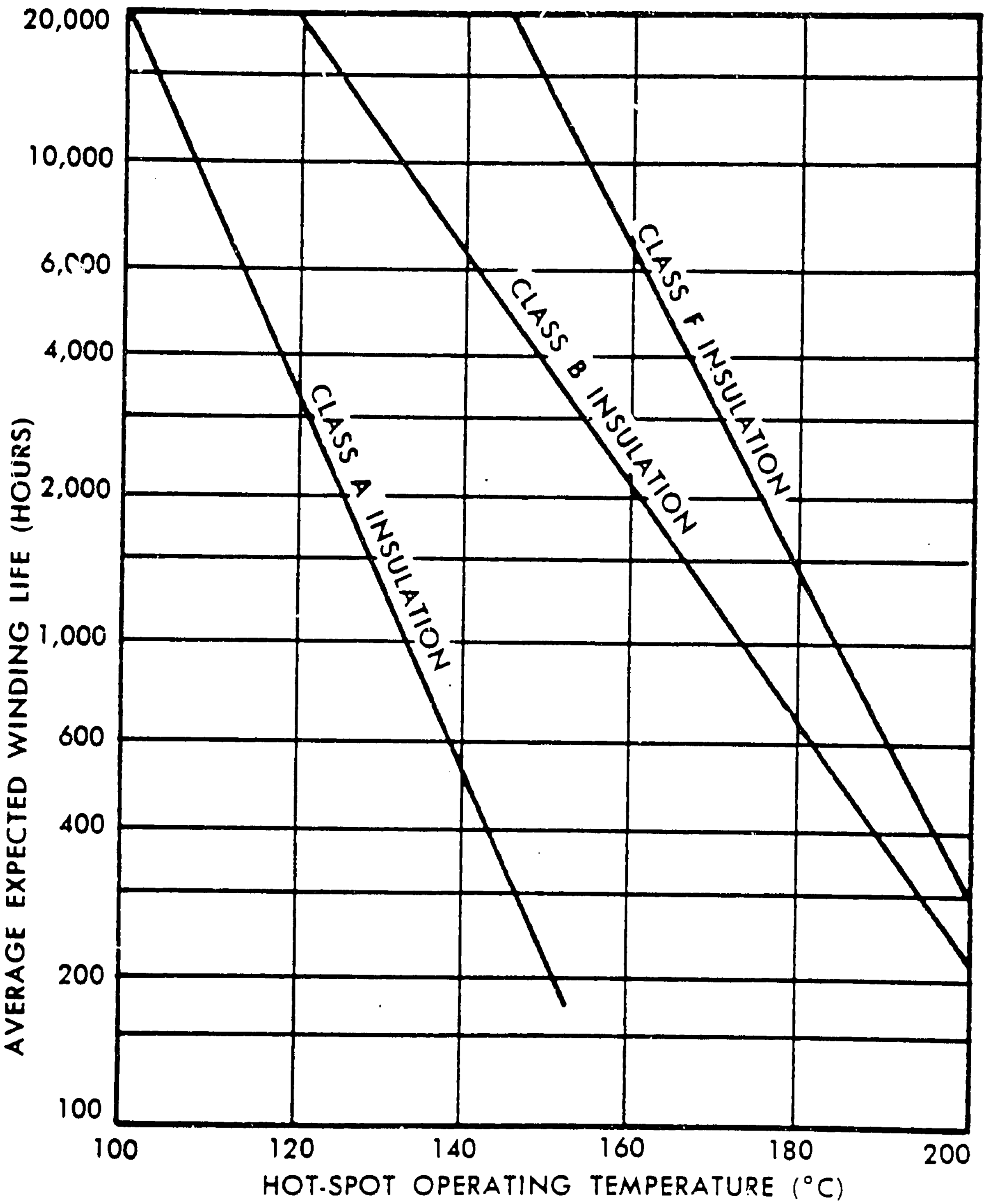
Exhibit 20.4 shows the effect of abnormally high motor temperatures on insulation life. Note that relatively small increases in hot spot temperature can cause a severe shortening of effective insulation, and hence motor, life. A good rule of thumb is that for every 10°C increase in motor operating temperature over the recommended hot spot temperature limit, winding life is cut in half. The converse is also true: for every 10°C decrease in motor operating temperature under the rated limit, the winding life is doubled.

The list below shows some of the items that should be checked regularly to ensure proper motor operation in your plant. These items are:

- Inspect motors regularly (at least annually) to detect wear in bearings, housings, and for dirt and dust in motor ventilators.
- Check load condition to ensure that the motor is not over- or underloaded. A change in motor load from the last test indicates a change in the driven load, and the cause should be identified and corrective action taken as needed. Load tests can be conducted at the time of normal motor inspection or on a continuous basis if permanent instrumentation is installed.
- Replace worn brushes. Worn brushes can cause damage to rotating motor parts, as well as dropping the motor's operating efficiency owing to increased electrical resistance.
- Keep commutators clean. Much as with worn brushes, dirty commutators will have a detrimental effect on motor efficiency.
- Take extra care in lubrication. Motors should be lubricated in accordance with the manufacturer's recommendations, but care should be exercised not to over-lubricate. Excess oil or grease from the motor bearings can enter the motor and saturate the motor insulation, causing premature failure and possible a fire.
- Watch alignment. Check periodically for proper alignment of the motor and the driven element. Improper alignment can cause shafts and bearings to wear quickly, resulting in damage to both the motor and the driven element.
- Be sure that the supply wiring is properly sized and installed. At regular intervals (usually annually), inspect the connections to the motor and starter to be sure that they are clean and tight.

Exhibit 20.4



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A reference guide can be used to identify the most likely causes of motor trouble (see Exhibit 20.5).

Energy Conservation Opportunities

In this section, motors are considered as independent units, ignoring the effect of the driven equipment. The best way to save electrical energy is to shut off the consuming equipment. For motors, this means evaluating a plant or building's operating schedule and ensuring that idle or unnecessary equipment is secured. The need to secure partially loaded equipment is shown in Exhibit 20.6, which shows motor operating efficiency and power factor as a function of motor load. Operation at reduced load does not proportionally reduce the energy consumption of the motor. The effect of the reduced efficiency and power factor is that at 20 percent of load, the motor is still drawing about 50 percent of the power required to operate the motor at full load.

Data from load readings discussed in the earlier section of this session can be analyzed to determine if the motor for a particular application is properly sized. It has been normal practice in the past to size motors for the worst case condition to ensure the operation of a system under any circumstances. This practice was acceptable when both the cost of purchasing energy and building new power plants were relatively inexpensive. In today's environment, however, it is both wasteful and costly to continue this practice. Wherever possible, oversized motors should be replaced with smaller motors of adequate size to improve the operating efficiency of both the individual piece of driven equipment as well as the system as a whole.

When selecting a replacement for either an oversized motor or one that has failed in service, consideration should be given to installing a high efficiency motor as a replacement. There are several styles of improved motors on the market today. The most common are the conventional electric motors that have been re-engineered with improved conductors in the field and rotor windings reducing I^2R and windage losses. Typical efficiency improvements are about 3-5 percent, depending on the load factor of the motor, for motors rated between 5 and 100 hp. Energy-efficient motors cost between 15 and 20 percent more than standard motors; hence, paybacks can be less than 3 years. The second type of retrofit that is becoming more common is the Wanless

REFERENCE GUIDE TO PROBABLE CAUSES OF MOTOR TROUBLES

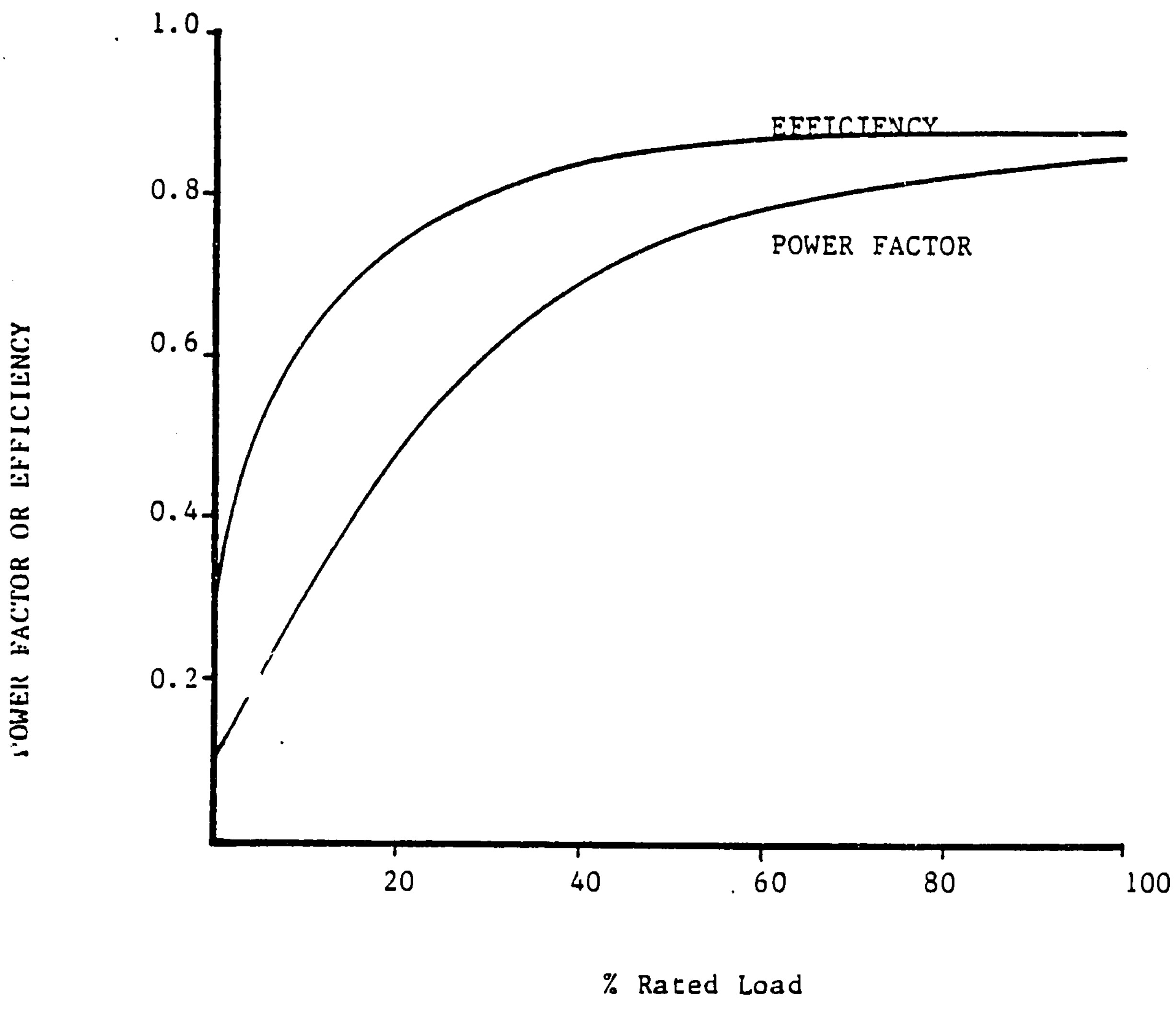
Motor Type	A. C. SINGLE PHASE				A.C. POLYPHASE (2 or 3 phase)	BRUSH TYPE (Universal, Series, Shunt or Compound)
	SPLIT PHASE	CAPACITOR START	PERMANENT-SPLIT CAPACITOR	SHADED POLE		
TROUBLE	***PROBABLE CAUSES**					
Will not start	1, 2, 3, 5	1, 2, 3, 4, 5	1, 2, 4, 7, 17	1, 2, 7, 16, 17	1, 2, 9	1, 2, 12, 13
Will not always start, even with no load, but will run in either direction when started manually.	3, 5	3, 4, 5	4, 9		9	
Starts, but heats rapidly.	6, 8	6, 8	4, 8	8	8	8
Starts, but runs too hot.	8	8	4, 8	8	8	8
Will not start, but will run in either direction when started manually—over heats.	3, 5, 8	3, 4, 5, 8	4, 8, 9		8, 9	
Sluggish—sparks severely at the brushes.						10,11,12,13,14
Abnormally high speed—sparks severely at the brushes.						15
Reduction in power—motor gets too hot.	8, 16, 17	8, 16, 17	8, 16, 17	8, 16, 17	8, 16, 17	13, 16, 17
Motor blows fuse, or will not stop when switch is turned to off position.	8, 18	8, 18	8, 18	8, 18	8, 18	18, 19
Jerky operation—severe vibration.						10,11,12,13,19

***PROBABLE CAUSES**

1. Open in connection to line.
2. Open circuit in motor winding.
3. Contacts of centrifugal switch not closed.
4. Defective capacitor.
5. Starting winding open.
6. Centrifugal starting switch not opening.
7. Motor over-loaded.
8. Winding short circuited or grounded.
9. One or more windings open.
10. High mica between commutator bars.
11. Dirty commutator or commutator is out of round.
12. Worn brushes and/or annealed brush springs.
13. Open circuit or short circuit in the armature winding.
14. Oil-soaked brushes.
15. Open circuit in the shunt winding.
16. Sticky or tight bearings.
17. Interference between stationary and rotating members.
18. Grounded near switch end of winding.
19. Shorted or grounded armature winding.

Exhibit 20.6

Motor Efficiency Vs Load Level



motor. This method involves remanufacturing the existing motor to improve its operating efficiency. The approach that is taken in a particular situation depends on the size of the motor, energy costs, annual hours of operation, and the cost of purchase or remanufacture. A 25-hp motor manufactured as a Wanless motor costs about $30,000 in the United States. Energy savings give simple paybacks between 3 and 5 years.

Another option to improve motor operating efficiency is to install a variable-speed drive on a motor. Variable-speed drives or load controllers enable a motor to follow the load of the driven equipment while maintaining close to peak operating efficiencies. The benefits of speed control will be discussed in a later part of the session; here we will present the basic methods in current use and some of their inherent limitations.

Speed control of direct-current (DC) motors can be achieved using either large resistor banks to control field voltage or through the application of specific solid-state drives to provide continuously variable speeds from zero to the design limits of the motor. DC motors can provide extremely high starting torques, but often require more maintenance than alternating-current (AC) motors since they have brushes and commutators that are subject to mechanical wear.

Ther are many methods for achieving variable speed control of AC motors, ranging from simple dual windings to sophisticated solid-state controls that shape the frequency of the voltage supply to reduce motor speed. The most common is the dual wound induction motor, which provides for two operating speeds, depending on which winding is active. These type motors are commonly applied in air conditioning systems where two different fan speeds may be required at different times of the year. Continuously variable-speed control using AC motors can be obtained either by using variable-ratio power transmission systems or by varying the motor speed directly.

A number of variable-ratio power transmission systems exist, including traction drives, hydraulic drives, eddy current drives, and variable-diameter pulleys. Traction drives and variable-diameter sheaves are generally used at low power applications. Hydraulic drives and eddy current clutches can drive heavier loads but are less efficient than belts or gears, particularly at the lower end of their speed ranges.

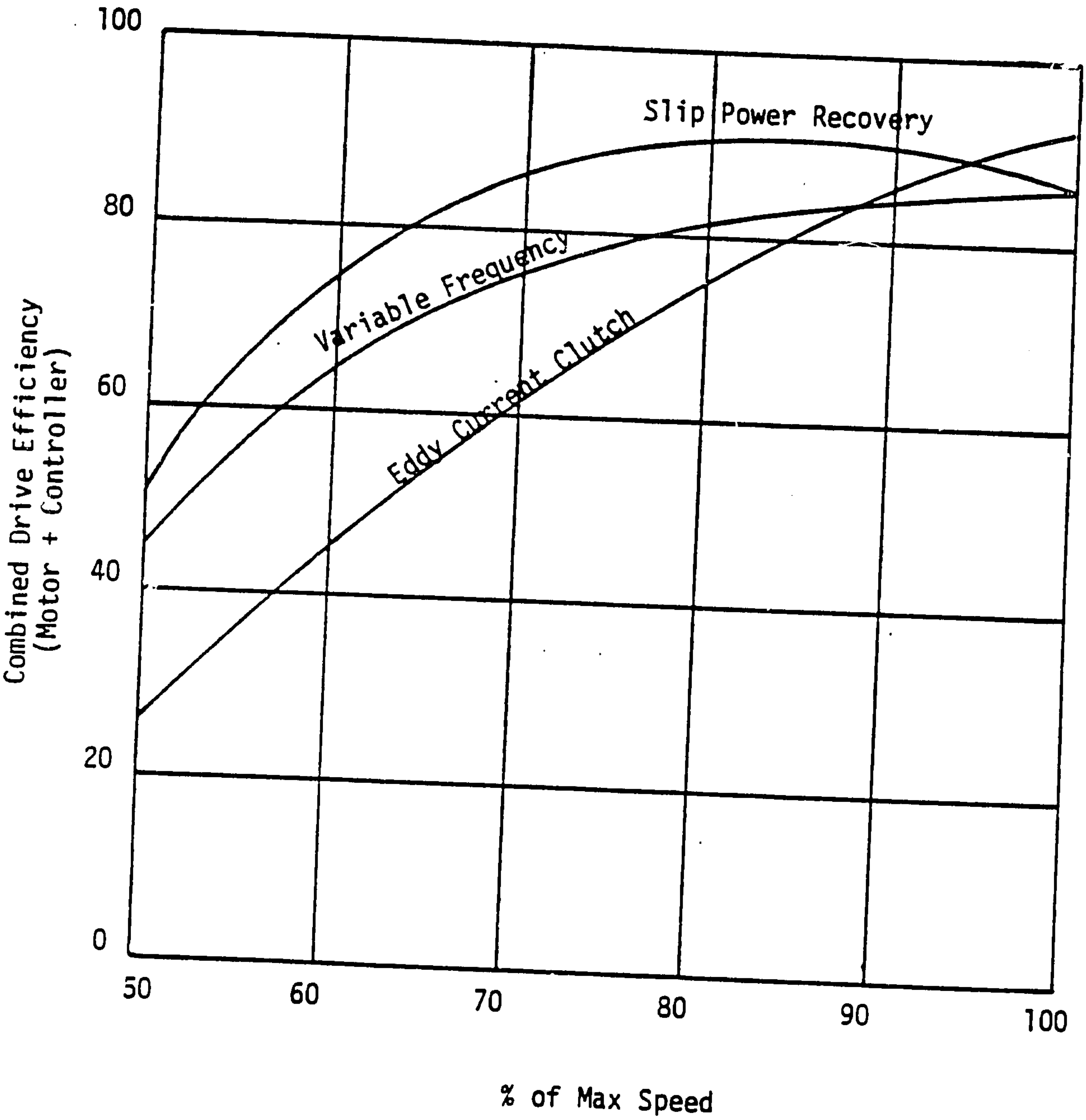
The most efficient method of speed variation is to control motor speed directly. For AC motors, this is possible by using one of two methods: variable-frequency AC motor drives or slip-power recovery systems. Variable-frequency drives are used with standard squirrel cage induction motors and are available in sizes up to several hundred horsepower. These units work by converting the AC line power to DC and then back to AC at a frequency required to operate the motor at the desired speed. The speed of rotation of an induction motor is dependent on the number of poles and the frequency of the supply voltage, so that for a fixed number of poles in a motor, the speed of rotation is dependent only on the frequency of the supply voltage.

Slip-power recovery systems are used with wound rotor motors and work by controlling the impedance of the rotor winding. Early model speed controllers for wound rotor motors operated by inserting a resistance in the rotor winding circuit and dissipating the excess energy as heat. Modern systems rectify the rotor current to line frequency and feed it back into the supply line, reducing the overall consumption of the motor. This system is the most efficient form of motor control available today. Note that this form of control can be used only on wound rotor motors. Where it is desired to use slip-power recovery on an installation with an induction motor, it will often be necessary to replace the motor. The added costs of the motor replacement often make this conversion unattractive. Exhibit 20.7 shows a comparison of drive efficiencies for the three common types of speed control currently in use for AC motors.

LIGHTING SYSTEMS

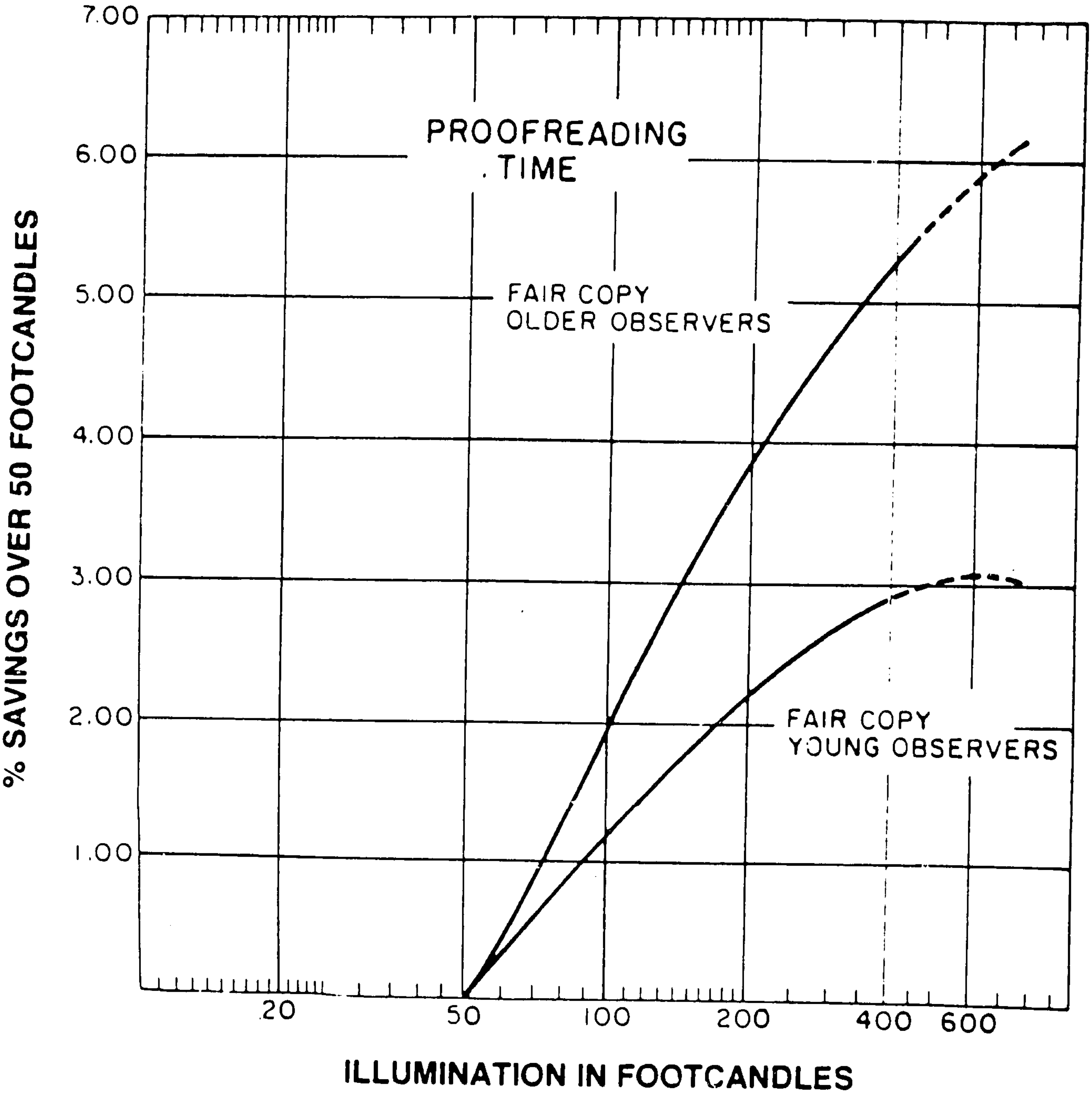
Proper selection of lighting systems is critical from both the aspect of operating plant efficiency and maintaining acceptable levels of productivity. Many studies have been conducted in recent years showing the relationship between variations in lighting level and worker productivity. As there is a direct relationship, care must be exercised in developing and implementing a lighting conservation program to ensure that any cost benefits achieved from reductions in lighting load are not offset by a greater loss in revenue from lowered worker productivity. The results of one study of worker productivity as a function of varying light levels are presented in Exhibit 20.8. Observation of productivity trends show a direct relationship between increased light levels and improved worker productivity. The task of the energy conservationist is to evaluate the

Exhibit 20.7



100
80
60
40
20
0
Combined Drive Efficiency
(Motor + Controller)
Slip Power Recovery
Variable Frequency
Eddy Current Clutch
50
60
70
80
90
100
% of Max Speed

Exhibit 20.8



Time for proofreading declines as illumination levels increase, indicating the lighting-productivity relationship

Source: IERI, program report #4

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tradeoff between productivity and energy consumption to achieve the best overall combination.

Different types of light sources available and their relative efficiencies are presented. The predominant lighting source used throughout the world for lighting in commercial and industrial facilities is the conventional fluorescent fixture. Recent advances in technology have led to reduced power requirements for essentially the same or slightly reduced lighting levels. Other systems coming into use for industrial applications are the several types of high-intensity discharge lighting now available on the market. In the following paragraphs, these systems will be briefly described and the advantages of each presented.

Lighting Sources

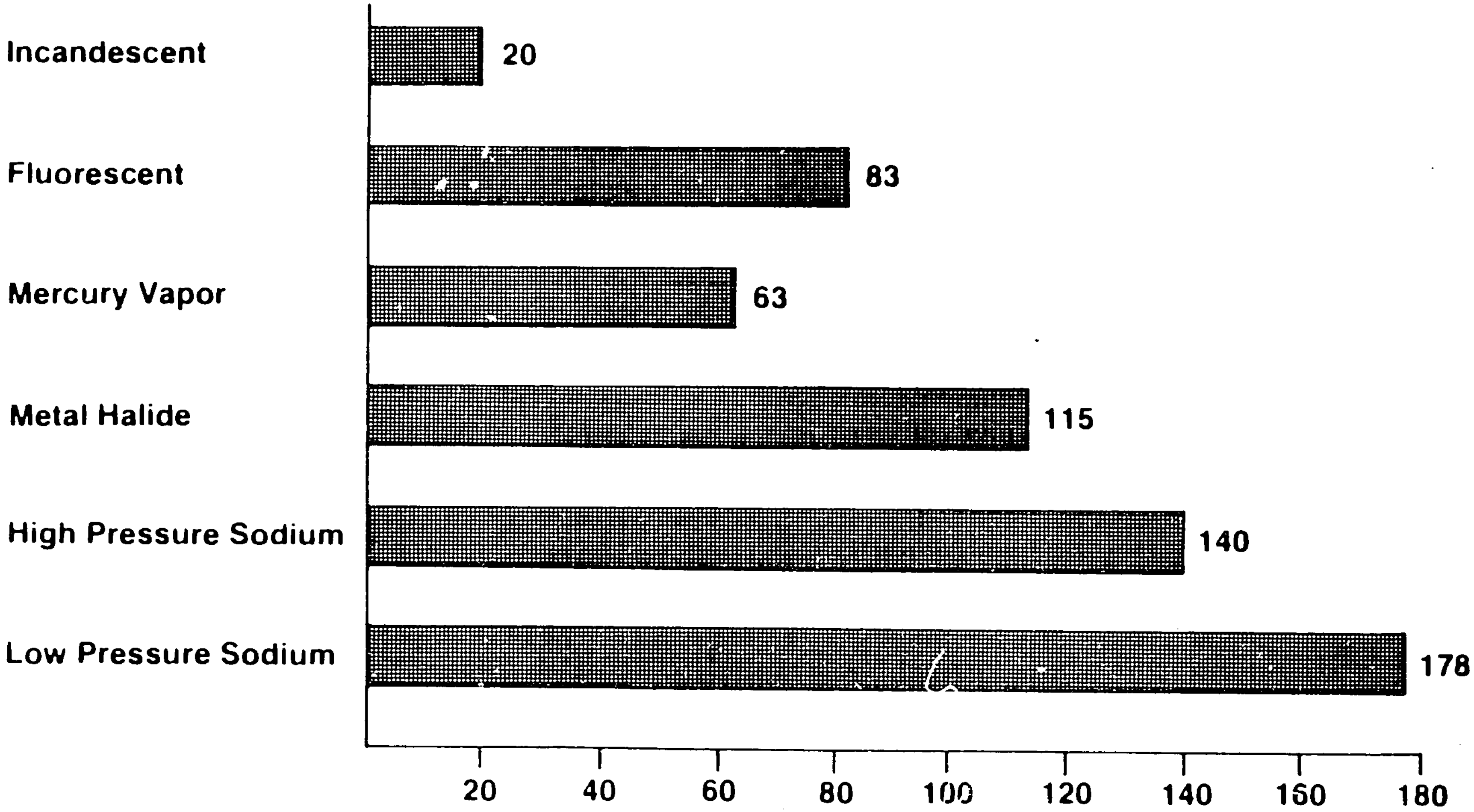
The multitude of light sources can be broken down into three basic categories: incandescent, fluorescent, and high-intensity discharge (HID). Each of these has its own characteristics that make it more or less suitable for a particular application.

The most important characteristic of a light source from an energy viewpoint is the efficiency with which it converts electrical energy into usable light. The measure commonly used is lumens per watt (LPW) or light output per watt input. Exhibit 20.9 shows the general range of LPW for each type of light source.

The chart separates the HID family into mercury vapor, metal halide, and high- and low-pressure sodium. The values presented ignore the effect of ballast loads that are required to operate fluorescent and HID lamps.

In addition to considering the absolute efficiency of a light source, consideration must also be given to system efficiency. Efficiency of a lighting system is the efficiency with which light is delivered to the seeing task, and determines the cost of the light and energy used to deliver it. Therefore, system efficiency -- the lamp/fixture/ ballast combination -- should be the basis of selection of a light source, not just lamp efficiency.

Comparative Efficiencies (in Lumens Per Watt) of Different Lamp Types



Source The National Lighting Bureau

Incandescent Lamps

An incandescent lamp is the least efficient source of electric light available (17 to 24 LPW). In an incandescent fixture, light is generated by passing electricity through a tungsten filament in an inert atmosphere. The resistance of the wire causes the element to heat up and glow, producing visible light.

Although the incandescent lamp is an inefficient converter of electrical energy, there are many applications where it is used. Incandescent fixtures are particularly suitable where light control from a point source is required. An example is display lighting in a store or museum. The incandescent source is a point source that lends itself well to fine control, resulting in a high system efficiency if properly applied.

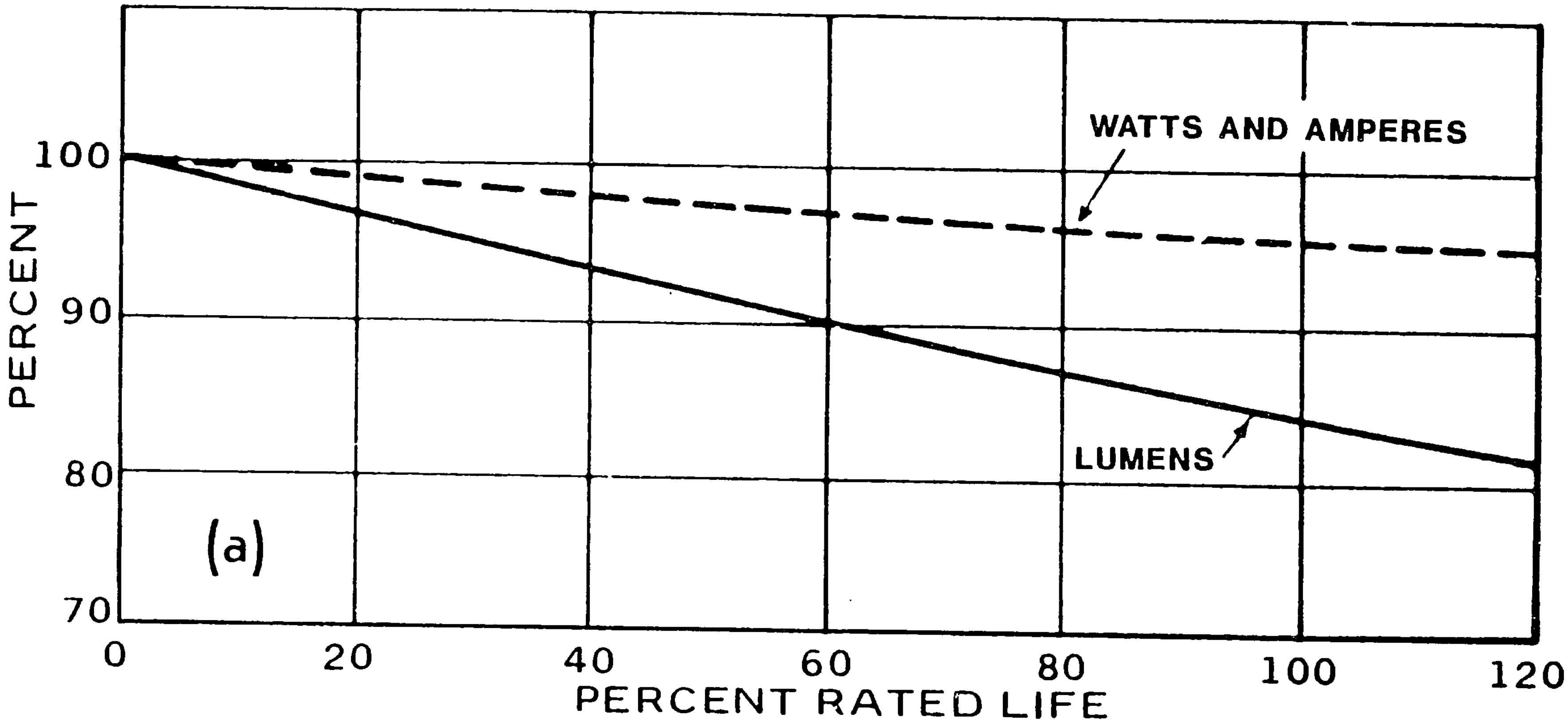
Lumen depreciation is caused by changes in the characteristics of the filament. As the filament burns, it slowly evaporates, becoming smaller in diameter and allowing less current to pass through it, thus reducing the power consumed. At the same time, the lumen output falls off owing to the lower filament operating temperature and blackening of the inside of the bulb. Exhibit 20.10 shows the characteristics of a typical incandescent lamp as a function of rated life.

Fluorescent Lamps

Fluorescent lamps are the predominant light source around the world. The fluorescent lamp is an electrical discharge source that makes use of ultraviolet energy generated at high efficiency by mercury vapor in an inert gas (argon, neon, krypton) at low pressure to activate a coating of fluorescent material (phosphor) on the inner surface of a glass tube. The coating acts as a transformer converting the ultraviolet light into visible light. A conventional 40-watt fluorescent bulb converts approximately 23 percent of the available energy into visible light, as opposed to 11 percent for an incandescent bulb; this translates into 74 to 100 LPW for fluorescent lamps, excluding the effects of ballast operation.

Fluorescent lamps, in common with all discharge lamps, must be operated with a ballast that provides the required starting voltage and limits the current draw. The more the

Exhibit 20.10



current in the arc increases, the more the resistance of the arc increases, so the arc in the fluorescent lamp would "run away with itself" and draw so much current that it would destroy the lamp if it were not controlled. Limiting current draw of the lamp is the most important function of the ballast. Each fluorescent lamp requires a ballast designed for its electrical characteristics, type of circuit, and the voltage and frequency of the power supply.

An important consideration in the specification and selection of ballasts is the ballast's power factor. Power factor is the ratio of real power to apparent power in an electric circuit. For the inductive load of a simple ballast, this causes a lagging power factor of 50 to 60 percent, making the electric supply system work harder to supply a given amount of real power. Modern ballasts are built with compensating capacitors in their circuits to correct this problem.

Fluorescent lamp output drops rapidly during the first 100 hours of lamp life (as much as 10 percent) and so published "initial lumen" figures are the value measured after this first 100 hours. After that time, the dropoff in light production is much slower for the balance of the lamp's useful life. The two principal reasons for the depreciation in light level are (1) a gradual deterioration of the phosphor coating, and (2) a blackening on the inner surface of the tube caused by the emission of metal from the cathode. Exhibit 20.11 shows the light characteristics of three typical fluorescent lamps -- (1) 40-watt rapid start (F40), (2) high output (HO), and (3) very high output (VHO).

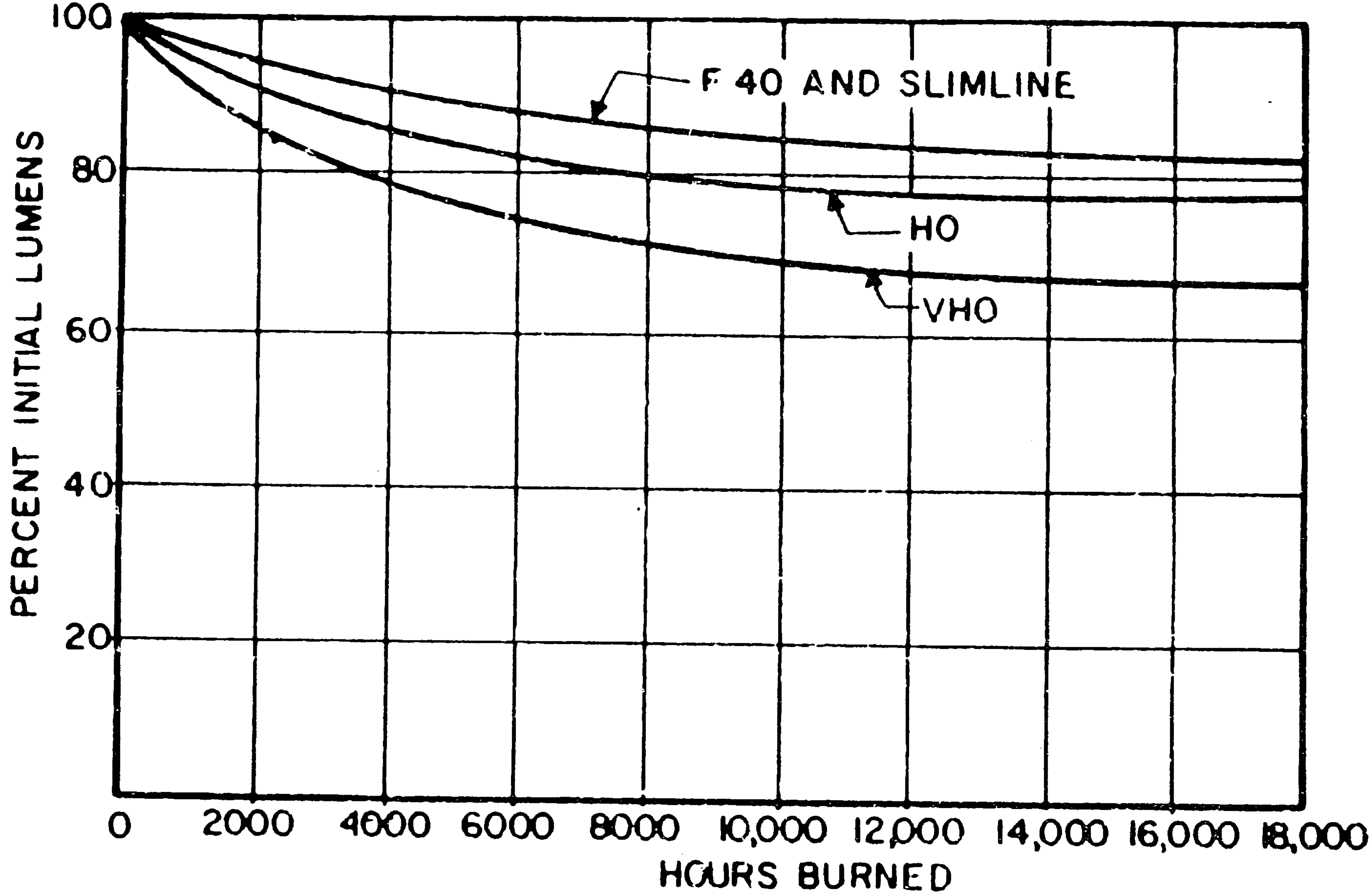
Fluorescent lamps have become the standard light source for many applications, particularly in commercial environments, because of their high relative efficiency, the diffuse nature of the light source, and the ability to tailor the light source characteristics to meet a variety of color rendition and daylight simulation criteria.

High-Intensity Discharge (HID) Lamps

There are several types of lamps in this category, including:

- Mercury vapor
- High-pressure sodium

Exhibit 20.11



- Low-pressure sodium
- Metal halide or multi-vapor.

The basic operating principle of all these lamps is the same. Light from these lamps is produced by the passage of an electric current through a gas or vapor under pressure, similar to the fluorescent lamp described earlier. Because of the many variations in gas mixtures and firing methods used, no attempt will be made here to describe in detail the operating systems of each type of lamp in the HID group. It is sufficient to note that the lamps have varying operating efficiencies and are generally more efficient than incandescent and fluorescent lamps. The one exception is the mercury vapor lamp, which falls between incandescent and fluorescent lamps in efficiency.

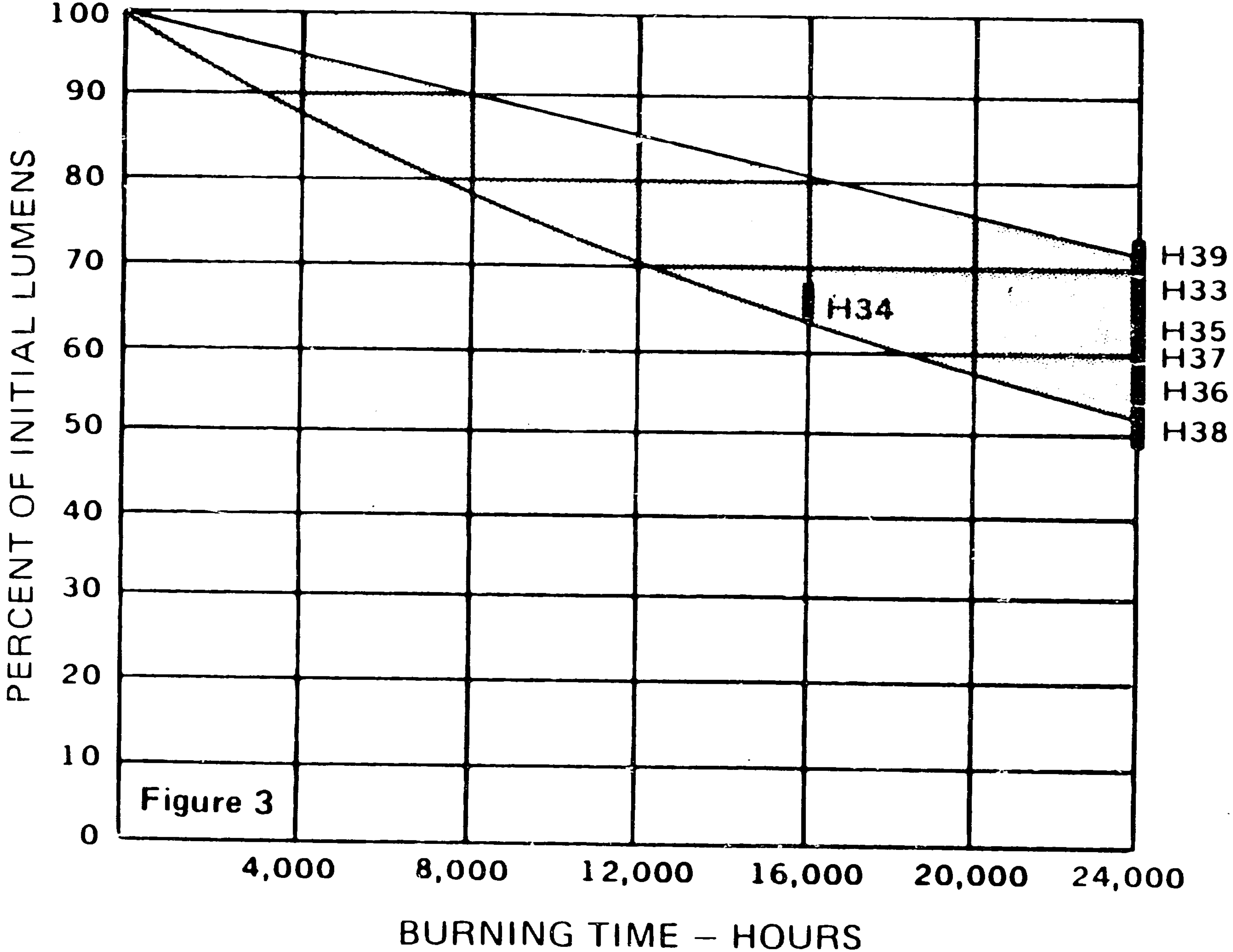
In common with other light sources, the light output of HID lamps decreases over time, principally as a result of the deposit of emission materials from the electrodes on the wall of the lamp. A lumen depreciation curve for a mercury vapor lamp is presented in Exhibit 20.12. While the curves for other types of HID lamps are not identical to this curve, the general shape of the curves is similar.

HID lamps are generally used in applications where large open areas must be lighted. The most common application is for street and yard lighting, although many of these lamps are becoming popular for the illumination of large manufacturing areas and warehouse and storage areas. The advantages of high efficiency in light generation make these lamps a natural selection wherever applicable.

One characteristic of low-pressure sodium lamps should be mentioned. While these lamps are the most efficient light source currently available, they are a monochromatic light source. This means that with the exception of yellow, there are no other perceivable colors under low-pressure sodium lamps. The potential disadvantages of this situation are obvious, and care must be exercised in their application.

Operation and Maintenance

The efficiency of many existing lighting systems can be significantly improved by the application of some simple steps to ensure that all of the light being paid for is put to use.


100
90
80
70
60
50
40
30
20
10
0
PERCENT OF INITIAL LUMENS
H39
H33
H34
H35
H37
H36
H38
Figure 3
4,000
8,000
12,000
16,000
20,000
24,000
BURNING TIME – HOURS

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The first step is to check the facility's operating schedule. It is likely that there are many periods during a work week when it is not necessary to maintain light levels in the building, as the space is either unoccupied or being cleaned or inspected by security. During these periods, lighting should be provided at reduced levels or can be secured completely. Obviously, when the lights are off, no power is being used and energy is being conserved.

The second step is a physical survey to determine the condition of the fixtures. Dirty fixtures, broken or aged diffusers, and old bulbs near the end of their life are all conditions that contribute to reduced lighting system efficiency. Part of this survey should also check the condition of the building walls and ceilings. Dirty walls or dark painted surfaces reduce the amount of reflected light.

After the steps above have been completed, a lighting level survey should be undertaken. The first phase of this survey is to determine what actual light levels are throughout the facility at representative work locations, in storage areas, corridors, offices, and other plant locations. Next, the measured lighting levels from areas where similar work is being performed should be compared to see what is the lowest reasonable level at which worker productivity is still acceptable. Results should then be compared with levels recommended by the Illuminating Engineering Society or a similar agency. Exhibit 20.13 shows the recommended illumination levels for a variety of classes of work activities. The levels are only recommendations and should be considered as the maximum to be supplied.

The lighting survey provides the basis for all future recommendations for changes to the existing lighting system. The first result is recommendations for delamping and reductions in light level. A second might be to recommend replacement of conventional fluorescent bulbs with high-efficiency tubes. The most costly result of the survey would be the recommendation for outright replacement of part or all of the existing system with an alternate light source.

One common technique employed to maintain lighting system efficiency is group relamping on a scheduled basis. Group relamping is the replacement of all the lamps in a defined area on a predefined schedule. Lamps are subject to a lamp characteristic known as "lumen depreciation." The amount of light produced by a lamp degrades over

Exhibit 20.13

RECOMMENDED ILLUMINATION LEVELS IN FOOTCANDLES

I Illuminance Categories and Illuminance Values for Generic Types of Activities in Interiors

Type of Activity	Illuminance Category	Ranges of Illuminances		Reference Work-Plane
		Lux	Footcandles	
Public spaces with dark surroundings	A	20-30-50	2-3-5	
Simple orientation for short temporary visits	B	50-75-100	5-7.5-10	General lighting throughout spaces
Working spaces where visual tasks are only occasionally performed	C	100-150-200	10-15-20	
Performance of visual tasks of high contrast or large size	D	200-300-500	20-30-50	
Performance of visual tasks of medium contrast or small size	E	500-750-1000	50-75-100	Illuminance on task
Performance of visual tasks of low contrast or very small size	F	1000-1500-2000	100-150-200	
Performance of visual tasks of low contrast and very small size over a prolonged period	G	2000-3000-5000	200-300-500	
Performance of very prolonged and exacting visual tasks	H	5000-7500-10000	500-750-1000	Illuminance on task, obtained by a combination of general and local (supplementary lighting)
Performance of very special visual tasks of extremely low contrast and small size	I	10000-15000-20000	1000-1500-2000	

Examples of applying the recommended values to specific tasks are given below for office and industrial assembly tasks. For a complete list of various tasks, consult the IES Lighting Handbook, 1981 Reference Volume, pages A3-A17. Consult page A-19 for weighting factors for room reflectances, task and worker characteristics.

Offices

- Accounting (see **Reading**)
- Conference areas (see **Conference rooms)**
- Drafting (see **Drafting)**
- General and private offices (see **Reading)**
- Libraries (see **Libraries**)
- Lobbies, lounges and reception areas C
- Mail sorting .... E
- Off-set printing and duplicating area .... D

Assembly

- Simple .... D
- Moderately difficult .... E
- Difficult .... F
- Very difficult .... G
- Exacting .... H

the life of the lamp at a predictable rate. Instituting group relamping programs enables the user to ensure a uniform light level over the lamp's useful life cycle, thereby reducing the total number of fixtures required as well as providing for planned replacement of lamps and maintenance of fixtures.

Lighting System Retrofit

Significant energy savings can be achieved through modifications to existing lighting systems either through reduction in the total number of active fixtures or by replacing present lamps with more efficient ones. Lamp replacement runs the range from simple bulb changing to complete replacement of the existing system. In most plants, the final program will likely incorporate a variety of elements, resulting in a program somewhere between the two extremes.

In the case of incandescent lamps, there are three basic options. The first is to relamp with an incandescent lamp of lower wattage or different design that better directs the generated light. The second alternative is to use one of the many direct screw-in replacement fluorescent bulbs to relamp the incandescent fixture. A replacement for a 60 incandescent saves 38 watts with no loss of light. The cost of a replacement lamp is $15 in the United States. Payback periods are usually around 1 year. The final alternative is outright replacement of the present lamp and fixture with a completely new light source, either fluorescent or HID. The option chosen in a particular situation will depend on the lighting requirements and the local implementation costs. Replacement of incandescents with HIDs usually have payback periods between 1 and 2 years in facilities that operate on a three-shift basis.

Recent advances in the design of fluorescent lamps and ballasts gives the end user a multiplicity of direct replacement high-efficiency lamps to choose from. Exhibit 20.14 shows a typical listing of conventional fluorescent lamps for a variety of applications and the high-efficiency replacements suggested by General Electric. The use of a particular replacement lamp should be reviewed against the constraints imposed by the manufacturer for its application. An example is that some high-efficiency lamps cannot be used in environments where the ambient temperature is below 15°C. High-efficiency lamps can usually be justified, as the incremental cost increase over a standard lamp

Exhibit 20.14

REDUCED WATTAGE/WATT-MISER LAMP AVAILABILITY

Operating Characteristics	STANDARD LAMP (You are now using)	Nominal Watts	Color	Nominal Watts	AVAILABLE IN: WATT-MISER	WATT-MISER "II"
Rapid Start—36"	F30T12/CW/RS	30	Cool White	25	F30T12/CW/RS/WM	
	F30T12/WW/RS	30	Warm White	25	F30T12/WW/RS/WM	
Preheat—60"	F90T17/CW	90	Cool White	82	F90T17/CW/WM	
Rapid Start—Preheat—48"	F40CW	40	Cool White	34	(Rapid Start Only) F40CW/RS/WM	(Rapid Start Only) F40LW RS/WMII
	F40CWX	40	DeLuxe Cool White	34	F40CWX/RS/WM	
	F40WWX	40	DeLuxe Warm White	34	F40WWX/RS/WM	
	....		Rite-White	34	F40RW3/RS/WM	
	F40D	40	Daylight	34	F40D/RS/WM	
	F40W	40	White	34	F40W/RS/WM	
	F40WW	40	Warm White	34	F40WW/RS/WM	
Slimline—48" 425 Ma	F48T12/CW	40	Cool White	30	F48T12/CW/WM	F48T12/LW/WMII
Slimline—96" 200 Ma	F96T8/CW	50	Cool White	40	F96T8/CW/WM	
Slimline—96" 425 Ma	F96T12/CW	75	Cool White	60	F96T12/CW/WM	F96T12/LW/WMII
	F96T12/CWX	75	DeLuxe Cool White	60	F96T12/CWX/WM	
	F96T12/WWX	75	DeLuxe Warm White	60	F96T12/WWX/WM	
	....		Rite-White	60	F96T12/RW3/WM	
	F96T12/D	75	Daylight	60	F96T12/D/WM	
	F96T12/W	75	White	60	F96T12/W/WM	
	F96T12/WW	75	Warm White	60	F96T12/WW/WM	
	F96T12/C50	75	Chroma 50	60	F96T12/C50/WM	
High Output—96" 800 Ma	F96T12/CW/HO	110	Cool White	95	F96T12/CW/HO/WM	F96T12/LW/HO/WMII
	F96T12/CWX/HO	110	DeLuxe Cool White	95	F96T12/CWX/HO/WM	
	F96T12/WW/HO	110	Warm White	95	F96T12/WW/HO/WM	
Power Groove—48" 1500 Ma	F48PG17/CW	110	Cool White	95	F48PG17/CW/WM	
Power Groove—96" 1500 Ma	F96PG17/CW	215	Cool White	185	F96PG17/CW/WM	F96PG17/LW/WMII
	F96PG17/WW	215	Warm White	185	F96PG17/WW/WM	
1500 Ma —96"	F96T12/CW/1500	215	Cool White	185	F96T12/CW/1500/WM	

is around $0.50-$0.75. If ballast replacement is included, outright replacement is often difficult to justify. Paybacks are usually in excess of 7 years.

For existing HID systems, the opportunities for retrofit are more limited, owing to the many different types of ballast and bulb mounting systems in use. Where these systems are inadequate, the solution will generally involve outright replacement. When this is done, ensure that the new system provides adequate lighting for minimum operating cost with maximum flexibility for control.

Exhibit 20.15 is provided as a means of rapidly estimating the potential annual savings achievable from reductions in lighting load. When performing the calculation for discharge type lamps, be sure to add in the load of any ballasts disconnected. This chart can also be used to compare lighting systems by entering at the connected kW for each system and comparing operating costs.

The ability to control is the key to the successful management of any system. Lighting systems are no different. Unfortunately, in many existing facilities, no provision was made at the time of construction for the control of the plant's lighting systems. In most cases, a single switch or breaker controls an entire floor or bay, making it difficult to regulate lighting levels as a function of area use. Under these circumstances, it is necessary to evaluate the economics of providing additional circuits for system control.

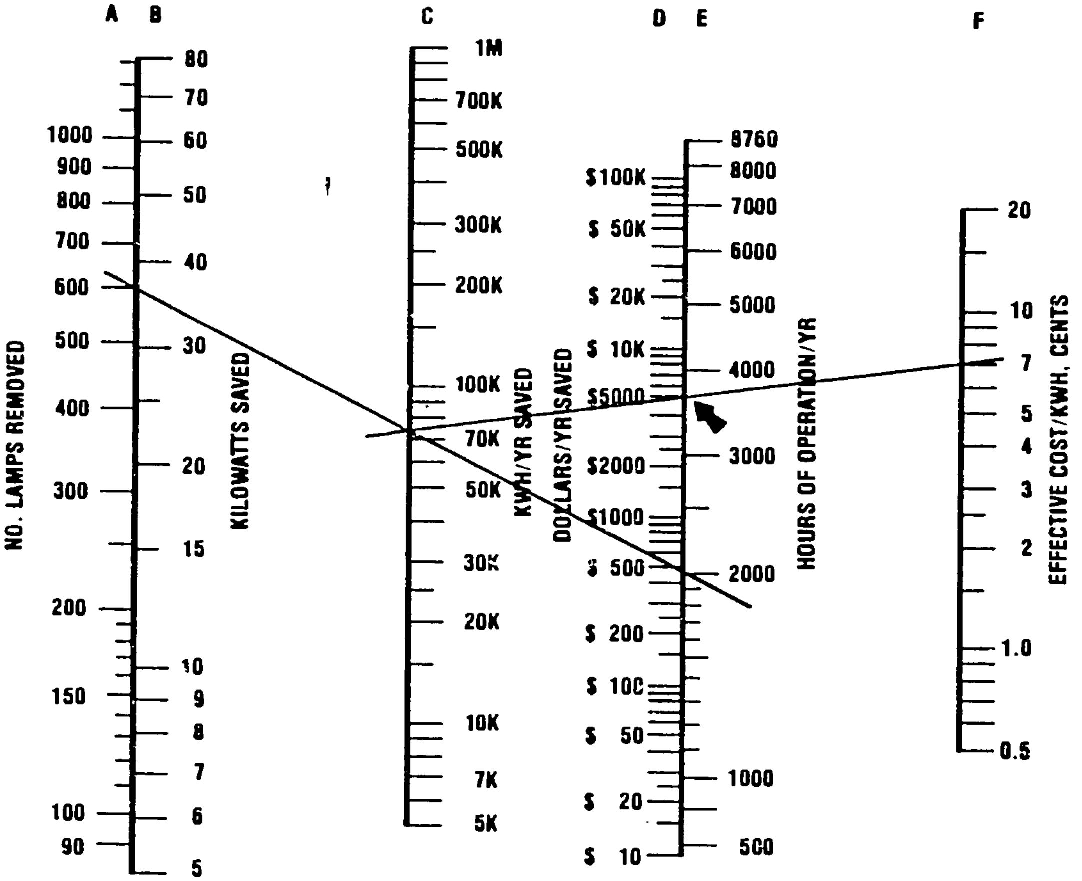
Numerous devices are available on the market today to aid in the control of plant lighting systems. These range from simple time clocks to sophisticated devices that sense whether or not a space is occupied and turn the lights on and off automatically. For most commercial and industrial applications, the most common control devices are time clocks and photocells.

Time clocks are devices that are programmed to turn the lights on and off in a particular area according to a predetermined schedule. This schedule normally tracks the facility's daily operating schedule with allowance for those who arrive early or leave late. Additional levels of control can imposed to allow for the various lighting requirements of normal operation, plant clean-up, and security tours.

NOMOGRAPH FOR DETERMINING APPROXIMATE ENERGY SAVED BY REMOVING LAMPS

ENERGY EQUALS MONEY—

Here is a conversion chart that tells you how much you will actually save in dollars based on the geographical costs of KWH and as a function of square footage of your building.



INSTRUCTIONS FOR NOMOGRAPH

1. Locate number of lamps to be removed on scale A.
2. Place straightedge from number of lamps to hours of operation per year on scale E.
3. Mark intersection with scale C. This is the number of KWH that will be saved per year, including air conditioning.
4. Place straightedge from mark made in step 3 to effective cost per KWH on scale F.
5. Mark intersection with scale D. This is the approximate dollar savings per year realized by removing the lamps.

COMMENT:

1. If the number of lamps to be removed is more than 1000, divide the number by 10 and use the nomograph. Then multiply the savings by 10. If the number of lamps is less than 100, multiply the number by 10, use the nomograph, and divide the savings by 10.
2. Kilowatts saved (scale B) includes an allowance of ½ watt of air conditioning for each watt of lighting, which is typical of medium-sized installations.
3. Effective cost per KWH (scale F) should be determined by allowing for fixed charges, fuel adjustments, power factor charges, and any other charges made by the utility, the whole divided by KWH used to get the effective cost per KWH.

EXAMPLE:

600 lamps are to be removed from a lighting system. The system is operated 2000 hours/year, and the effective cost per KWH is 7¢.

Connect 600 on scale A with 2000 on scale E. The intersection with scale C is at 72,000 KWH, which is the amount saved per year. From this intersection, run a line (B) to 7¢ on scale F. The intersection with scale D is at $5000, which is the dollar amount that will be saved in energy per year.

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Photocells are generally used to control outside security lighting systems and control the exterior lighting as a function of ambient light levels. This method of control is preferable to time clock control for outside lighting, as conventional time clocks cannot readily account for seasonal variations in daylight hours or for local conditions caused by severe weather. Time clocks and photocells have relatively low capital investment requirements (typically less than $100), and if lamps can be grouped together, savings in energy can justify the capital expenditure in less than 12 months.

CONSERVATION OF ELECTRICITY IN SYSTEMS

Earlier, the principles of energy conservation for electric motors and lighting systems were presented. The following paragraphs discuss conservation of electricity at a system level, incorporating the effect of the driven equipment on the motor and how to ensure an efficient operating system. Also, the operating principles of some of the more common equipment driven by electric motors will be discussed, including:

- Fans
- Refrigeration systems
- Compressors.

Fans

Fans are used for a variety of purposes in industrial and commercial applications ranging from simple pedestal-mounted fans for personnel cooling to very large units used to supply conditioned air to office or commercial facilities. The key to conserving fan energy lies in three sequential steps: (1) reduce the resistance to air movement in the system; (2) reduce the quantity of air supplied to or returned from the conditioned space; and (3) limit the periods during which the fans operate. These steps will achieve maximum savings when executed sequentially.

Resistance to air flow in any system is a function of air volume delivered and duct configuration, intake louvers, supply and return air diffusers, heating and cooling coils, filters, dampers, and fan characteristics. Improvements in any of these system

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characteristics will result in reduced energy consumption and improved operating efficiency. Implementing energy conservation measures that reduce the heating or cooling load will permit reducing the air volume handled by a HVAC system. Whenever air volume is reduced, resistance to air flow is also reduced. Reducing resistance to air flow results in an increase in delivered air volume that, in turn, permits a reduction in fan speed to bring air volume down. For multivane centrifugal fans (the kind most commonly used in large HVAC systems), the power output varies directly as the cube of the speed; thus, any reduction in fan speed -- which is also proportional to delivered air volume -- results in a sizable reduction in fan power input.

The basic fan laws for centrifugal fans are as follows:

- Volume delivered varies directly with fan speed.
- Pressure varies directly with the square of the speed.
- Power input varies directly with the cube of the speed.
- Volume varies directly with the square of the pressure.

Most of the fan characteristics listed above are speed dependent and show the value of the motor speed control systems. Reducing fan speed has a significant impact on energy consumption. For example, a reduction in air volume of approximately 10 percent will reduce energy consumed by about 27 percent.

A second consideration is to reduce the quantity of air delivered to or returned from the conditioned space. The amount of air delivered is related to the cooling or heating load of a particular space and can be reduced if the load can be minimized. This is accomplished by evaluating the current loads against the design criteria and seeing if they were realistic. If (as is often the case) the system was oversized in the original design, or if loads have been reduced due to other conservation measures (e.g., additional insulation, improved glazing, reduced infiltration), the amount of conditioned air delivered can be reduced, resulting in savings in fan horsepower. An additional benefit of reducing air volume will be to reduce the load on the refrigeration or heating plant serving the area, thus generating additional energy savings.

Finally, by checking a facility's operating schedule, energy can be saved by not operating equipment when it is not necessary for the environmental conditioning plant to be running. Securing HVAC equipment when it is not required will reap obvious benefits in extended machine life. A fringe benefit will be the ability to schedule routing system maintenance for predictable down periods.

In summary, to conserve fan energy: (1) reduce heating and cooling loads; (2) reduce the resistance to air flow in the system; (3) measure the increased volume that results and determine the new air volume needed to meet the new loads; (4) reduce the fan speed accordingly; and (5) change the motor if necessary. Motor replacement will not normally be required; however, if the load on the existing motor is less than 40 percent of full load, consideration should be given to replacement with a smaller unit. Exhibits 20.16 and 20.17 are provided so that annual savings from reduced delivery volumes can be estimated. These curves are for centrifugal fans with forward and backward blades, the type of fans most commonly found in large central HVAC systems.

Refrigeration Systems

Mechanical refrigeration systems use compressors to raise refrigerant pressure and temperature, condensers to reject the heat of compression and change the refrigerant from a gas to a liquid, and evaporators to absorb heat from the transport medium (air or water). A schematic of a typical refrigeration system is shown in Exhibit 20.18.

The operating efficiency of all refrigeration equipment is evaluated as a function of the heat absorbed in the evaporator and the heat rejected in the condenser. This relationship is called the system coefficient of performance (COP) and is defined as:

$$\frac{\text{Heat absorbed in the evaporator}}{\text{Heat rejected in the condenser - heat absorbed in the evaporator}}\,.$$

Typical COP values range from 2 to 5 at full load. Machines operating with air-cooled condensers tend to operate at the lower end of the range. Refrigeration units can be operated as heat pumps, and the system COP tends to increase because some of the heat rejected from the condenser is put to useful work as heating.

COP is directly related to evaporating and condensing temperatures. For a water chiller using a cooling tower for condenser water, these temperatures are normally 4°C

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Exhibit 20.16

Source. Manufacturers fan capacity tables for forward-curve centrifugal fans.

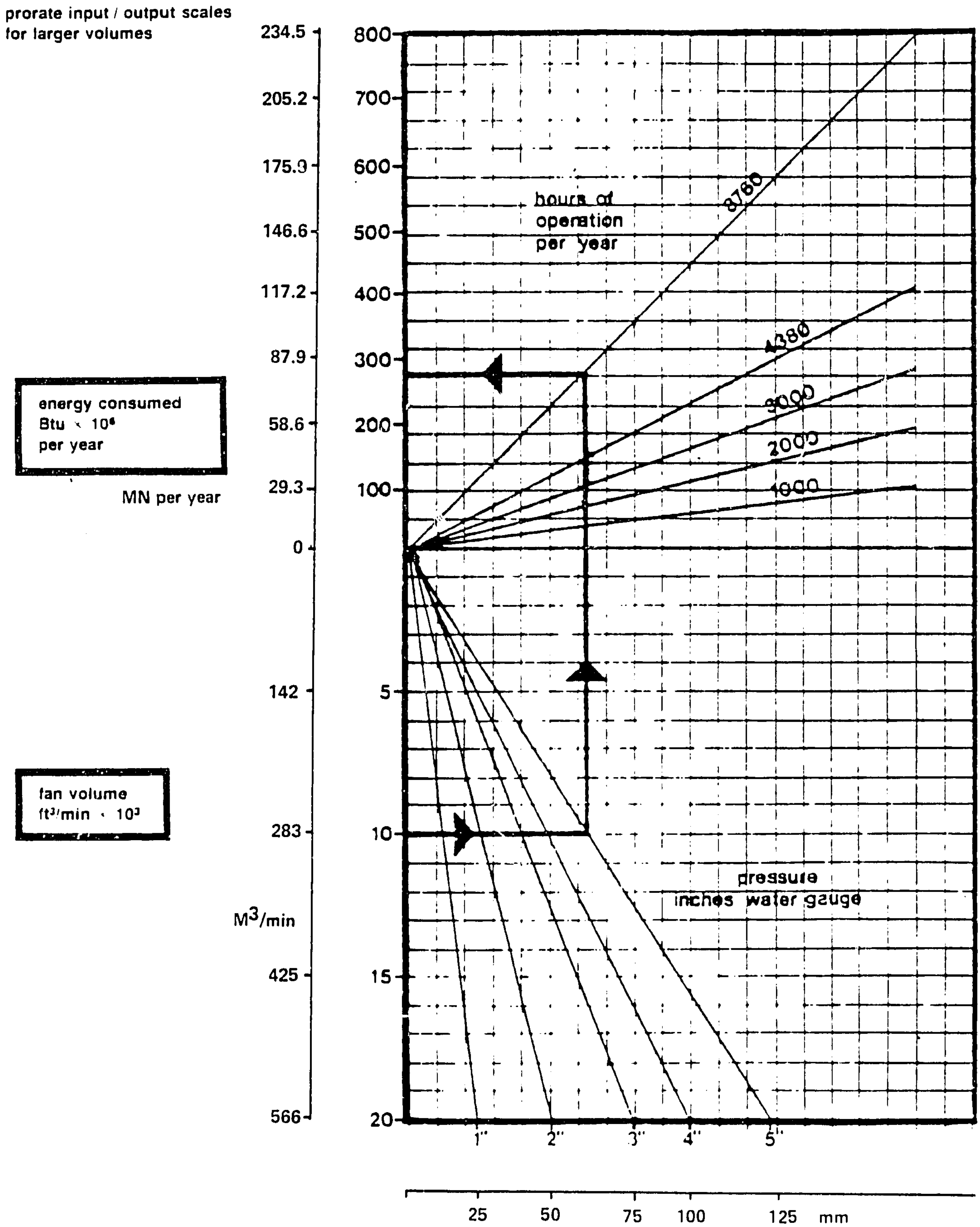

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Exhibit 20.17

Source Manufacturers fan capacity tables for backward curve centrifugal fans

prorate input/output scales for larger volumes

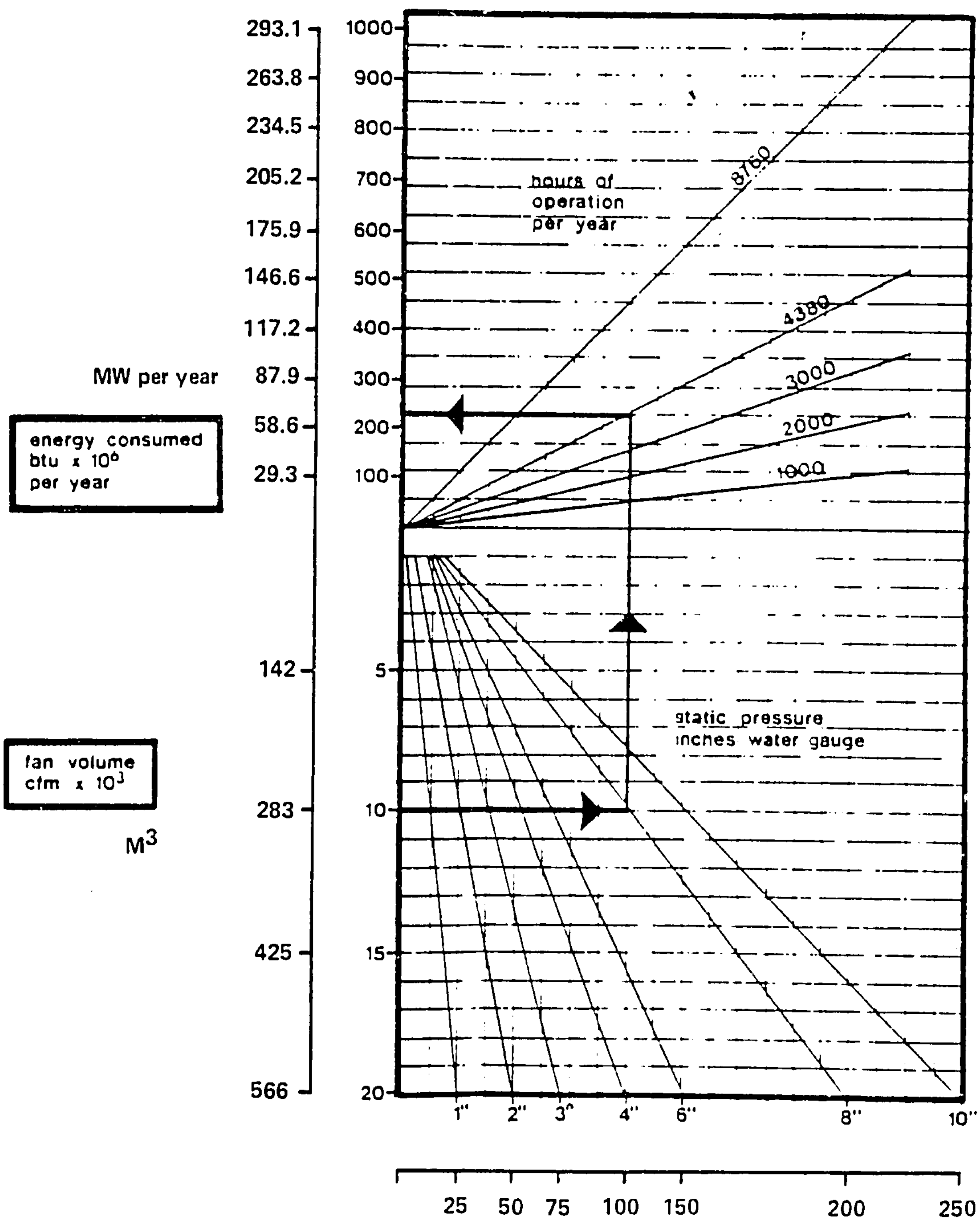
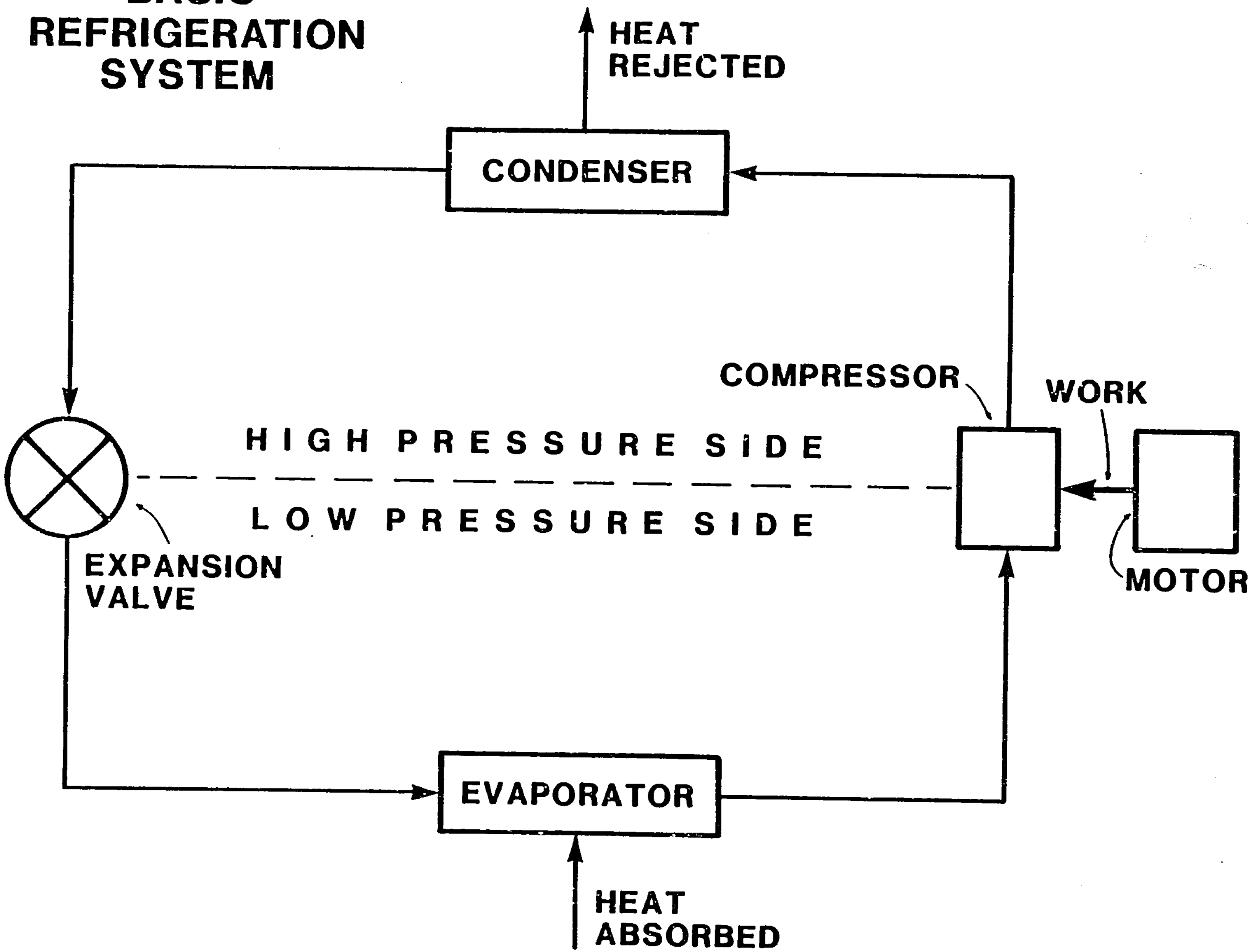


Exhibit 20.18

BASIC REFRIGERATION SYSTEM



and 40^oC, respectively. If evaporating temperature can be raised (by using chilled water at 10^oC rather than 4^oC), or if condensing temperatures can be reduced, the COP will increase and a greater cooling effect can be achieved for the same energy input; alternatively, the same cooling effect can be achieved for less energy input. In general, either raising the evaporator or lowering the condenser temperature by 5^oC to 6^oC will result in an increase in efficiency of approximately 20 to 25 percent at full load. At partial load conditions, the effect will be more marked, and on a seasonal basis the effect will be greater than would be indicated by consideration of full load operating conditions only.

Compressors

Compressors are also used to compress air and other gases for use in buildings and plants. The most common use is to provide compressed air for process use and to drive process control systems. Compressed air is also commonly used as a power source for tools such as drills, impact guns, hammers, etc. This discussion will center on compressors used in central station applications that supply air to an entire system or complex.

Compressors can be divided into two basic types: positive displacement and centrifugal. There are a number of subtypes within the first group (i.e., reciprocating, vane, rotary screw, and lobe types). In general, positive displacement compressors are used to meet system demands ranging from fractions of a cubic meter per minute (cmm) to approximately 200 cmm (7,000 cfm). Screw compressors can be used for loads of up to 70 cmm (2,500 cfm), and vane compressors can handle loads up to 15 cmm (500 cfm). Centrifugal compressors do not become efficient until the load is in the range of 65 to 70 cmm (2,300 to 2,500 cfm).

In addition to the compressor, there are a number of components common to any compressed air system. Exhibit 20.19 shows a basic system configuration. The function of each piece of equipment is described briefly:

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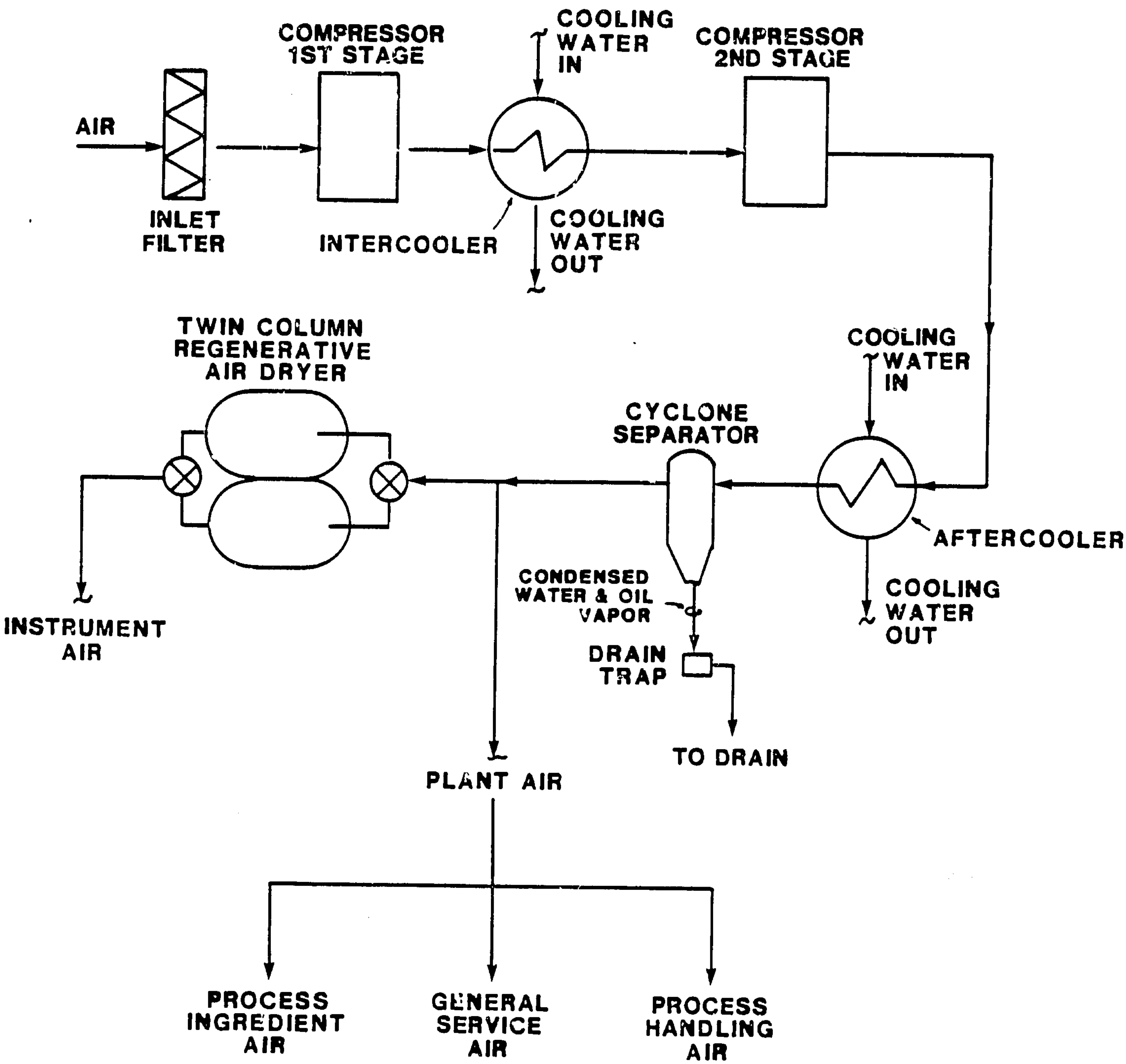
Exhibit 20.19

TYPICAL COMPRESSED AIR SYSTEM



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- Filter -- removes dirt and dust from the incoming air to prevent excessive wear. This is particularly important for centrifugal and screw compressors that have extremely close internal tolerances.
- Compressor, first stage -- compresses air from atmospheric to an intermediate pressure.
- Intercooler -- removes the heat of compression generated in the first stage. Intercooling reduces temperature of the air entering the next stage, lowering the specific volume of the air and reducing the physical size and horsepower requirements of the subsequent stage. Using multi-stage compression with intercooling uses less energy than single-stage compression because intercooling reduces the temperature and volume of the air, allowing the same weight of air to be compressed with less horsepower.
- Compressor, second stage -- compresses air from intermediate to discharge pressure. For a typical plant system using air at 7 bar, only two stages of compression are used, although many centrifugal machines may use three stages. For process compressors operating at very high pressures, it is not unusual to see machines with 10 to 15 stages, and even 20 stages are not uncommon in the petroleum refining industry.
- Aftercooler -- reduces the heat of compression added in the second stage, bringing the air temperature down to a level where it can be safely used. Also in the aftercooler, oil and water vapor are condensed so they will not be transmitted through the distribution system.
- Separator -- collects and removes the oil and water vapor condensed in the aftercooler.
- Receiver -- serves several functions. It (1) dampens pressure pulsations; (2) separates, collects, and removes any remaining condensed water and oil vapor; and (3) provides storage for compressed air to level out the load on the compressor by providing a reserve for peak demand periods.
- Dryer -- removes additional water vapor to prevent control failures owing to condensation and/or freezing of water vapor in instruments. Some processes also require dry air.

There are many ways in which the operating efficiency of an existing compressor system may be improved. The following is a list of typical projects that apply to small and medium-sized industrial facilities.

- Use extra air receivers. In some situations, the use of additional air receivers to provide extra storage capacity may relieve the need to add more air compressors to meet short-term peak demands.
- Eliminate air use during non-operational hours. On machines that use control or process air and are shut down for extended periods (nights and weekends), install electric solenoid or control valves to turn off the air to the machine when it is shut off. This type of control will control idle air loss on pneumatic controls that normally bleed 0.01 to 0.04 cmm (0.5 to 1.5 cfm) even in the standby mode.
- Use a time clock to control compressor operating hours. If the compressor serves only process users and is not required to support environmental or plant control systems during off hours, install a time clock control to secure the unit when it is not required. In situations where plant control air is also supplied from a large central unit, the potential for installing a small compressor for weekend or standby use should be considered.
- Locate and repair all piping leaks. Many manufacturing plants lose 10 percent or more of their compressed air through leaks in pipes at fittings, flanges, and valves. The air distribution system should be inspected annually at a minimum for leaks, unused lines, and unauthorized users. A 3-mm leak typically will waste 11 dm^3 per second at a pressure of 7 bar, which is equivalent to an energy requirement of 3.5 kW.
- Consider recycling compressor waste heat. Heat rejected by the compressor in cooling water or air is normally in the range of 35°C to 45°C. The heat available at this level can be used to produce process hot water, heat areas adjacent to the compressor room, or possibly preheat makeup water to the boiler plant. As a rule of thumb, heating boiler makeup water from 13°C to 35°C will save approximately 7.5 liters of No. 2 oil per 3,800 liters of makeup water.

The measures described above represent the basic initial measures that should be evaluated and implemented first in a program to improve the energy efficiency of a plant's air system. After these measures have been accomplished, plant management may wish to consider installing advanced load control systems that vary motor speed as a function of system demand or conduct an evaluation of the existing plant with the aim of installing a new, modern, properly sized, and efficient system.

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SESSION 21: ELECTRICITY USE, PART 2 — ENERGY MANAGEMENT IN HOTELS AND OTHER LARGE BUILDINGS

INTRODUCTION

Energy management is not only applicable to industrial process systems, but can be applied to any facility that consumes energy. In this session, we will outline practical and economic options to reduce energy costs in a hotel facility as an example of energy management in large facilities. It may be puzzling at first to see the connection between hotels and industrial facilities. However, many industrial plants have office and administration facilities that, although part of the industrial complex, function similarly to commercial buildings. Many of the conservation opportunities presented in the following session have been identified in industrial office buildings as well as in commercial facilities such as hotels.

The session will outline briefly a system of analysis which can be used by the energy auditor or coordinator to analyze these facilities. Specific energy cost reduction opportunities in kitchens, laundries, and hotel guest rooms are also presented.

SYSTEM OF ANALYSIS

For analysis purposes, a building or facility can be considered as a combination of several energy-consuming systems:

- Building envelope
- Lighting
- Ventilation
- Heating
- Cooling
- Water
- Special processes.

The systems interact to a certain extent but can be examined by an energy auditor on a stand-alone basis.

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Occupancy of a space has a major impact on the energy consumption in a building. Hence, buildings are often examined based upon their function and energy-consuming systems within functional areas. For example, a hotel can be divided into the following:

- Hotel room floors
- Public and private areas
- Kitchen and laundry.

Within each of the functional areas, the energy auditor can seek measures based on the performance of the consuming systems listed above.

The effect of function on energy consumption in a hotel is illustrated in Exhibit 21.1. Data shown are for a hotel in the Chicago area of the United States. The information was gathered by installing approximately 30 energy meters, including flow meters, and utility meterings. Normally, an energy auditor would not use that amount of instrumentation, but the results of the analysis are very revealing.

The hotel was divided into function areas -- hotel room floors, kitchen and laundry, and public and private areas. Even though they only occupy 6 percent of the total floor area, the kitchen and laundry account for some 49 percent of the energy use. In contrast, the guest rooms floors, which represent over two-thirds of the area, consume only 26 percent of the energy.

Energy use by system for the three areas is also shown in Exhibit 21.1. The analysis shows that the majority of the energy consumed on an area basis is used for process operations in the kitchen and laundry areas. Energy auditors should, therefore, focus their attention on these areas. The following is a list of no cost/low cost operating procedures that can be implemented in both food preparation and laundry operations. Energy savings opportunities in hotel guest rooms resulting from the use of occupancy sensors and energy management systems are also reviewed.

Exhibit 21.1

Hotel Energy Budget:
Breakdown by Area and Function

Function	10^3 Btu/ft^2/yr	MW/m^2/yr
Hotel-room floors (69% of area)		
Cooling	7.6	86.26
Domestic hot water	11.9	135.07
Heating		
corridor air	32.5	368.88
rooms	11.5	130.53
Light and power	29.6	335.96
Total	93.1	1,056.70
Kitchen and laundry (6% of area)		
Cooling	51.0	578.85
Process	1,093.0	12,405.55
Heating	228.0	2,587.80
Equipment	626.0	7,105.10
Total	1,998.0	22,677.30
Public and private areas (25% of area)		
Cooling	29.5	334.83
Heating		
lobby level	64.2	728.67
service floors	12.8	145.28
Fans	66.7	757.05
Garage ventilation	5.1	57.89
Elevators	15.4	174.79
Storage	25.7	291.70
Miscellaneous unaccounted	7.7	87.40
Total	227.1	2,577.61

By area (approximate — overall)

	% energy	% $
Rooms	26	32
Kitchen and laundry	49	37
Public and private areas	25	31
Total	100	100

Food Preparation

- Turn on equipment only as needed and make certain it is turned off at night.
- Keep equipment and door seals free of debris to prevent heat leakage and energy waste.
- Reduce "peak loading." Your electric bill is in part determined by a demand charge function of the highest (or peak) kilowatt use recorded during the billing period (usually measured by 15- or 30-minute periods). Some rules to reduce peak use and demand charges are:
  a. Schedule energy-intensive cooking, such as baking and roasting, during non-peak demand hours (periods in which the least amount of electric energy is being used in the kitchen and in other departments).
  b. Set a limit on the number of electric appliances that may be used at the same time.
- Set up a schedule of preheating times for kitchen appliances and stick to it. Equipment should be turned on at specific times to reach specific temperatures, and turned off when it is not needed. A 10- to 15-minute preheat period is sufficient for solid-top gas ranges. A deep-fat fryer requires only 7 to 15 minutes for preheating. Consult manufacturers' instructions for individual appliances.
- Ensure that thermostatic controls are operating properly. Maintenance of higher than necessary temperatures wastes energy.
- Set thermostats to the lowest temperature giving satisfactory results. Dialing higher does not reduce preheating time, while a low temperature results in lower energy consumption because less energy will be lost to the surrounding air.
- Regularly use a reliable commercial thermometer to check surface temperature against the control dial reading. If the readings do not match, your thermostat may need recalibrating.
- Plan menus to minimize energy usage. Meals that require less cooking time to prepare will use less energy and can still be appealing.

- Cook foods in the largest volume possible. Most food service operators find they can cook food in advance, thus making m_ e efficient use of energy.
- Keep all cooking surfaces clean. Build-up of grease and other encrusted matter reduces cooking efficiency by reducing heat transfer.
- Check cooking oil level frequently. Food must be covered with oil to cook correctly. Add fresh oil if level drops below marker. Cooking without sufficient oil wastes energy.
- Check the temperature of cooking oil often to be certain that heating elements and thermostat controls are working correctly.
- Clean heating elements at least weekly. This should be done daily if you do high-volume frying. Remove all traces of burned food, grease, or carbon.
- Have gas burners checked semi-annually by an experienced service representative.
- Regularly check all gas units for uneven or yellow flames. To correct the condition, clean the burners, pilot lights, and orifices with a stiff wire brush. If the flame is still yellow or even, have your serviceman correct the gas-to-air mixture by adjusting the air shutters.
- Regulate gas burners for optimum heating and energy efficiency. Adjust the flame until it is entirely blue and has a firm center cone. The tips of the flame should just touch the utensil bottom.
- If you must keep electric burners on for short periods when they are not actually in use, reduce the temperature until you are ready to cook. This will not only conserve energy, but it will also prolong the life of the burners. Only a few minutes are required to bring the surface of a solid-top range up to cooking temperature.
- Do not turn gas burners on until you are ready to cook.
- Fill cooking vessels according to manufacturer's recommendations, and to capacity, if possible.
- Use flat-bottom pots and pans to maximize heat transfer.
- Cover pots and pans with lids tp keep the heated air in and decrease cooking time.

- Burners should always be smaller than the kettle or pot placed on them. The diameter of the pot should be about 25 mm larger than the diameter of the electric coils or plates.
- Group kettles and pots on close-top ranges. By using as little surface area as possible, and adjusting heating elements to desired levels, heat loss will be decreased.
- Turn down heat as soon as food begins to boil, and maintain liquids at a simmer. Keeping the heat higher than the boiling temperature does not cook food any faster, and it uses more energy.
- Turn the burners down during slack periods. Use thermostatic control when possible to avoid continuously high or excessive heat.
- Place foil under range and griddle burners. The operating efficiency will improve, and the equipment will be easier to clean. (However, do not block air inlet openings for gas burners.)
- Remove boil-overs and spill-overs promptly to avoid build-up of carbon deposits that can adversely affect unit efficiency.
- Clean burners and be sure that openings as well as air shutters are clear. (Handle ceramic refractor units carefully.)
- Where possible, begin cooking food in a steamer. Then, finish it as necessary in the desired manner.
- When practical, consider using steam cookers for such items as vegetables, rice, and pasta to speed up cooking time. Only small amounts of energy are required to maintain the cooking temperature once it has been reached.
- Regularly inspect and clean interiors of fixed-well fryers for grease or carbon deposits.
- Do not load beyond manufacturer's stated capacity. Normally, baskets are loaded to one-half to two-thirds capacity. Crowded food takes longer to cook and wastes energy.
- Clean fryers regularly.
- Turn thermostat up only as high as required to reach frying temperatures (154°C-182°C). Preheat time from room temperature to 182°C is only about 5 minutes.
- Use a low or medium flame for light griddling.
- When practical, load heated broilers to capacity to use the entire surface area.

- Use infrared broilers to advantage. They can be turned off when not in use and quickly reheated.
- Turn char-broiler heat to medium after briquets are hot.
- Plan baking and roasting to use ovens to capacity. This eliminates bringing the oven to full heat more than once or twice a day. Energy is wasted when all of the available cooking heat is not used. In standard ovens, allow at least a 50-mm clearance for air to circulate around pans.
- Use warm-up time to begin cooking food (except for food that will dry out or overcook). Start the day's baking with foods that require the lowest oven temperature. Use other electrical appliances sparingly while preheating electric ovens to avoid excessive demand charges.
- Load and unload oven quickly to avoid unnecessary heat loss, and avoid opening doors to look at food. For every second an oven is open, the interior temperature can drop as much as 5°C.
- Wipe up spills frequently, and keep interior surfaces of oven clean.
- Clean and wipe out the grease troughs and remove any stuck-on food at least once a day.
- Repair broken door hinges and cracks that allow heat to escape from oven.
- Once or twice a year, check that ovens are level.
- Have the oven timer professionally checked at least once a year.
- Turn off rotary toaster when not in use.
- Clean rotary toaster regularly. Clean equipment performs more efficiently and uses less energy.
- Consolidate foods stored in refrigeration and freezer space where possible.
- Check to be sure that refrigeration units are not left running with little or no food in them. Consolidate small amounts of leftovers, and turn off those refrigeration units that are not needed.
- Set up procedures to reduce the time refrigerator and freezer doors are opened. Frequent and lengthy openings are extremely wasteful of energy. Plan ahead to take out or replace several items at one time. Clearly label stored items. Prepare schedules for use of walk-ins.
- Be sure that items do not jam against closing doors.
- Do not store anything within four feet of the compressor.
- Do not store products in front of coils in a manner that restricts air flow.
- Keep blower coil free of ice build-up and dust.

- Allow hot food a few minutes to cool before placing it in refrigerator or freezer. Air cooling reduces the amount of work that the refrigerator or freezer must do.
- Thaw frozen food in the refrigerator.
- Equip walk-ins with pilot lights on light switches.
- Turn off lights in walk-ins when leaving.
- Feel the outside walls for cold spots. Do this frequently for a new unit.
- Maintain proper tension on refrigerator compressor belts and replace worn or damaged belts.
- Schedule food deliveries, where possible, to avoid overloading refrigeration facilities, or undercapacity utilization.
- Close ice-maker storage bins after each use.
- Use hot tap water for cooking whenever possible. A water heater uses less energy than a range-top to heat the same amount of water.
- Drain and flush hot water tanks semi-annually. Accumulations of water impurities prevent the efficient transfer of heat to the water. Where water contains heavy amounts of lime or other sediment, drain and flush tanks more frequently. In areas with heavy lime deposits, consider installing a water conditioner to reduce the lime build-up. The heating coil should be removed and cleaned every year on storage-type tanks heated by a steam coil.
- Make sure that the power rinse on the dishwasher is turning off automatically when the tray has gone through the machine.
- When a power dryer is used, adjust it so that heated air is delivered just long enough to barely dry the dishes. Drying will continue after the machine is shut off.
- Consider using a wetting agent that will eliminate the need for power drying.
- Be sure that the dishwasher is shut off after use.
- Regularly check the flow controls to be sure that you use the proper amount of water in the rinse.
- Regularly check the rinse water temperature.
- Regularly check the speed reducer on conveyor-type washers for proper lubrication.

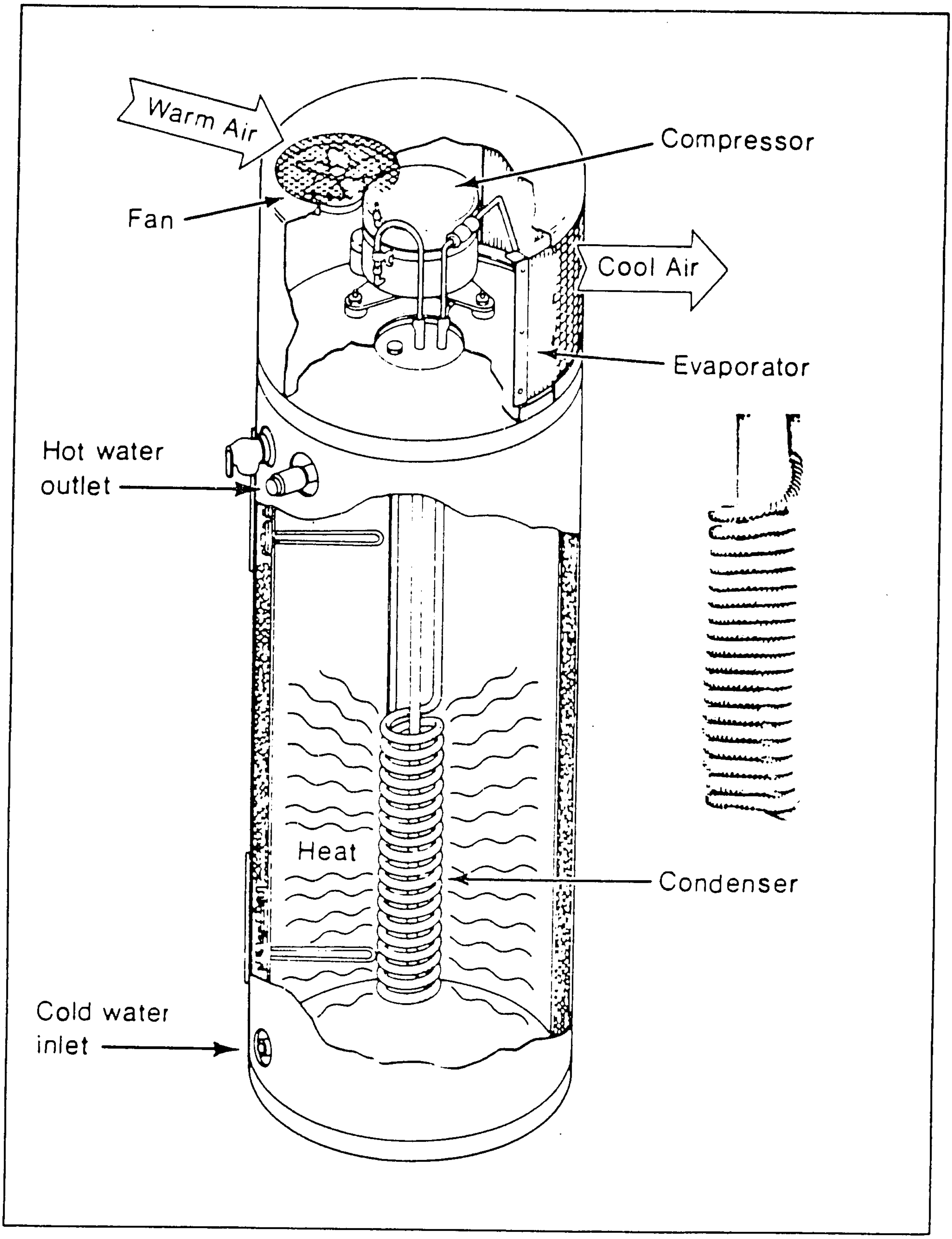
- Keep pressure reducing valves in full order. If you do not have one, check to see if it is needed. While dishes will not rinse thoroughly if the pressure is too low, higher than necessary water pressure will waste heated water.
- Inspect the feed drain valves weekly for water leakage.
- Inspect pumps monthly for water leakage.
- Check to see that the hot water lines in a recirculation loop are insulated.

In addition, we describe in the following two hot water energy-saving products that can be used in kitchens. The first product can be used in restaurants and kitchens to heat hot water wherever air conditioning is used: it consists of recovering heat by replacing the condensor for hot refrigerant from the compressor of the air conditioning unit. The size of the refrigeration load will determine the amount of heat recovered, but a 14-kW load typically will produce 341 liters per hour of 60°C water when the supply water is 15°C. Because the rate of water use is unlikely to coincide with operation of the air conditioning system, a storage tank is usually used in conjunction with the refrigerant water heater.

The second product to improve water heating conditions in kitchens is the heat pump water heater. The heat pump water heater operates basically like a window air conditioner except that it takes hot air from an area such as a kitchen cooking area (see Exhibit 21.2). Rather than exhausting hot air to the outdoors, it uses the hot air in conjunction with a compressor, evaporator, expansion valve, and refrigerant to gather the heat and a condensor located in a water tank to deposit it. The water tank is virtually a standard electrical hot water heater containing heating elements to supplement the condensor. As a benefit, cool air is provided into the kitchen space, thereby improving the working environment. This unit was developed with the support of the U.S. Department of Energy. The unit will deliver the equivalent of 2 kW for an energy input of 0.8-1 kW. Savings over traditional electric resistance heaters are 50-60 percent. An estimated installed cost for the system is $1,200 in the United States for a 40-gallon water heater.

Exhibit 21.2

Heat Pump Water Heater



Laundry

Hotels that do not have laundry facilities send out their laundry. Many hotels, however, have in-house laundry capabilities. The type of equipment used in laundry facilities can vary significantly. For example, drying can be completed by hot water, steam, or thermal fluids. The following list is not meant to be exhaustive; rather, it is meant to stimulate the energy auditor at a facility having laundry equipment to seek out conservation opportunities within these facilities.

- Develop concise operating procedures for each piece of equipment. Place instructions on or near the equipment.
- Iron only those items that require it.
- Use heated water only in the wash cycle, if practical.
- Wash and dry full loads only.
- Remove items from the dryer immediately after the drying cycle is completed to prevent wrinkling. This reduces the energy that otherwise would be required for ironing.
- Instruct workers to keep lint filters and exhaust hoods of dryers clean. Perform spot checks to ensure compliance.
- Operate exhaust systems installed over washers, flatwork ironers, tumblers, etc., only when needed. Check periodically for improper operation and repair as necessary.
- Consider rescheduling laundry work hours to avoid periods when the hotel experiences its peak electrical and/or steam demand.
- Reduce the water temperature to the minimum required by law.
- If using steam, reduce boiler operating pressure when laundry is not working, and check steam trap operation regularly.
- Check pipework insulation for damage on a regular basis.
- Return condensate to the boiler.
- Recover heat from hot rinse by heat exchanger.

There are also opportunities for energy conservation in peripheral services associated with hotels, such as vending machines and water coolers. These appliances are often neglected by the energy auditor; yet, they can waste relatively significant amounts of electrical energy if left to operate continuously. Electric water coolers can consume more than 1,000 kWh per year each and vending machine display lighting another 300-400 kWh per year. These amounts may not seem significant on their own, but when totalled can add up. Obviously, the control of the operation of these machines by time clocks can achieve noticeable savings.

Guest Rooms

Until recently, the options for conservation in hotel rooms were limited. New technology developments, such as occupancy sensors and energy management systems, have, however, enabled conservation measures to be implemented there.

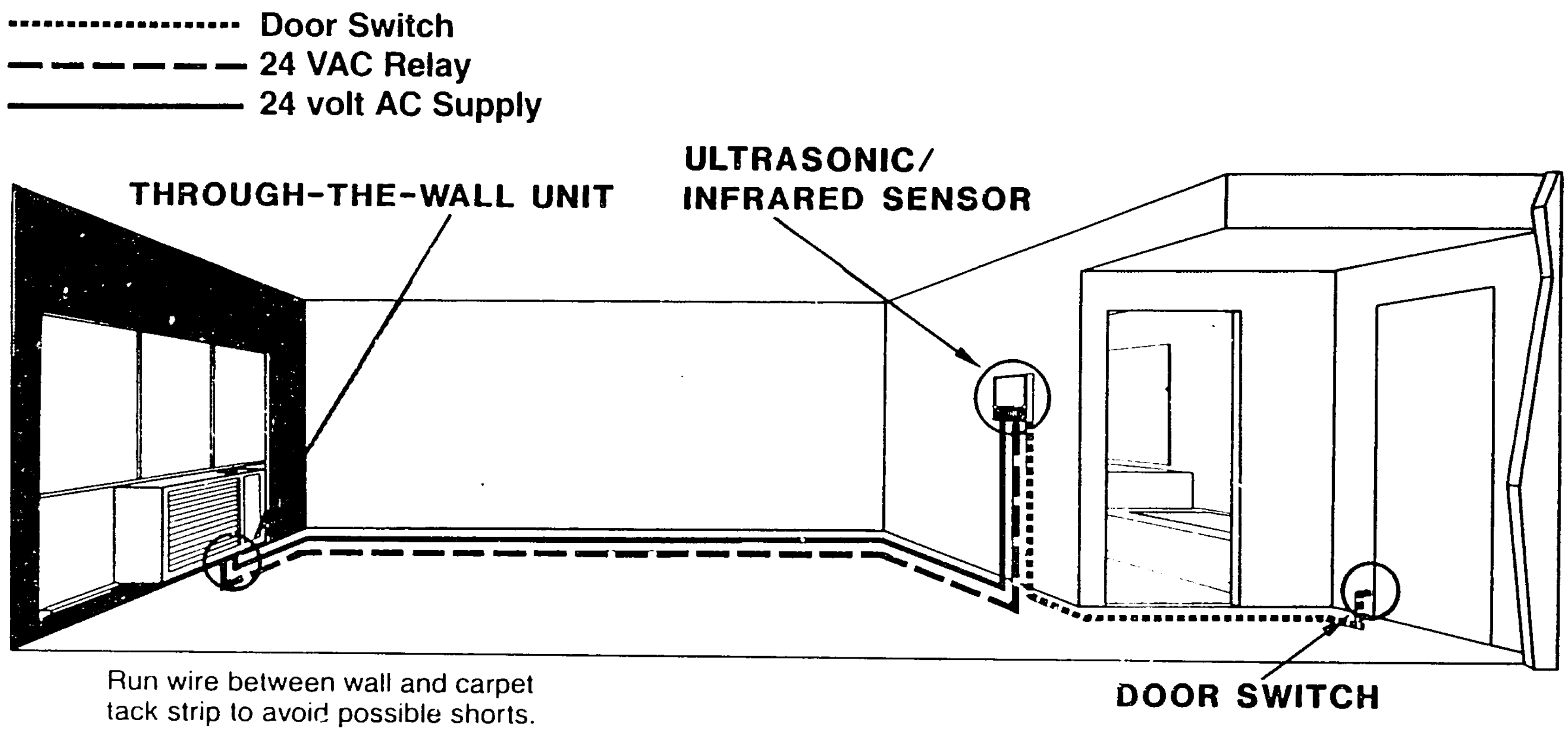
One major source of waste has traditionally been guest rooms, where, rather than risk compromising service, hotels permit guests to have individualized control via in-room switches for lights, air conditioning, etc. Often, however, guests do not turn off these services when they leave their room, and services are then provided irrespective of whether guests are in their room or not.

To combat this, hotel owners have installed in guest rooms **occupancy sensors,** infrared or ultrasonic, that detect whether the guest room is occupied. By linking the sensor to the control circuit of the HVAC and lighting systems, it is possible to have the equipment operate only when the guest is in residence. There are two major shortcomings with this method of control. First, because equipment will be turned on only when the room is occupied, conditions may not always be exactly to guests' liking when they first enter their room. Second, if the room is occupied and vacated during very short time intervals, equipment may suffer from excessive switching.

To overcome these problems, it is possible to use more sophisticated ultrasonic and infrared controllers that function in conjunction with the opening and closing of the guest room door. The occupancy sensor is normally installed on a wall and then connected to the HVAC control and a door switch (see Exhibit 21.3). The HVAC unit will operate under guest-selected settings whenever the room is occupied. When the guest leaves the room or the guest room door is opened, the occupancy sensor overrides the guest-selected controls and turns the unit off. The energy auditor can pre-select

Exhibit 21.3

TYPICAL GUEST ROOM INSTALLATION



temperature limits that will turn the HVAC back on if the unoccupied room temperature drifts.

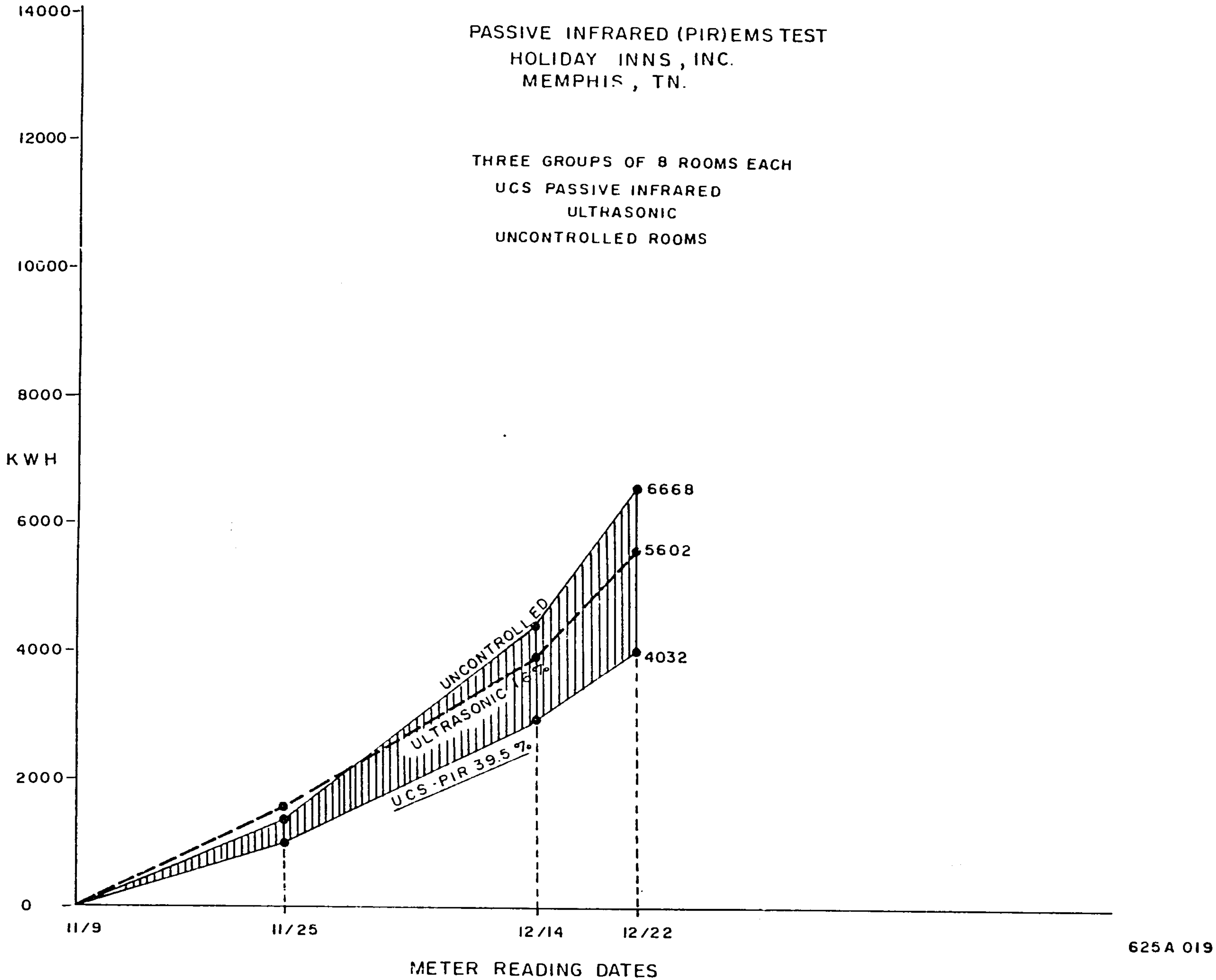
To prevent cycling of the unit when the door is opened, a minimum run interval can be selected. The minimum run interval will permit the HVAC unit to continue to operate for a predetermined time after the door is opened. This feature can be particularly useful for meeting rooms and hospitality suites where doors are often open even when the room is occupied. Alternately, it is possible to override the door-open control feature and control by occupancy sensing alone.

Energy savings by these forms of controllers were measured at a Holiday Inn in the United States. Three groups of rooms were monitored for energy consumption. One group of rooms had the normal control arrangement, one had ultrasonic sensors, and one infrared sensors. Exhibit 21.4 shows that the energy consumption for the rooms controlled by infrared sensors was 39 percent less than that of the uncontrolled rooms. The ultrasonic controller produced a 16-percent reduction in energy consumption. These savings levels are impressive. However, it should be realized that if a guest occupies his room continuously or if he turns off the HVAC system whenever he leaves his room, the savings will be much reduced. Typical costs (including installation) for ultrasonic or infrared controllers are $230 per room in the United States. Installation time can be as short as 1 hour. The occupancy sensor controller offers a totally automated approach to controlling consumption in guest rooms and can be adjusted to the individual needs of the space in which is it placed. These controllers function without the need for guest or staff involvement, and savings are achieved without the quality of the services provided to guests being compromised.

Energy use in guest rooms can also be reduced by installing **energy managment systems** (EMS) to centralize control of several energy consuming systems. The EMS interfaces with the existing controls of each consuming system and permits new control strategies to be employed. Depending on the sophistication of the EMS used, control strategies available include:

- Time of day
- Duty cycling
- Optimum start/stop

Exhibit 21.4



PASSIVE INFRARED (PIR) EMS TEST
HOLIDAY INNS, INC.
MEMPHIS, TN.
THREE GROUPS OF 8 ROOMS EACH
UCS PASSIVE INFRARED
ULTRASONIC
UNCONTROLLED ROOMS
14000
12000
10000
8000
6000
4000
2000
0
KWH
6668
5602
4032
UNCONTROLLED
ULTRASONIC 16%
UCS-PIR 39.5%
11/9
11/25
12/14
12/22
METER READING DATES
625A 019

- Sequential start/stop
- Demand control shedding
- Optimize hot and chilled water temperature
- Control boiler operation
- Control chiller operation
- Enthalpy control
- Night setback
- Economizer cycle.

In addition to the control features offered, some EMS systems have feedback capabilities and can provide a monitoring duty and supply information pertaining to consumption by interface with utility meters, as well as checking the operation of the units under control.

The most complex systems include full-facility management function capability, with alarm systems for fire and security applications in addition to programs for preventive maintenance planning.

Claims for savings made by EMS are often exaggerated, and the systems are seen to be the panacea for all energy ills. This is not the case in reality. Before considering an EMS, the energy auditor must complete an evaluation of the building and the potential for using an EMS. The evaluation should include analysis of the following:

- Existing utility rate schedules for all fuels
- Mechanical systems and their associated controls
- Operating characteristics of the spaces served by the above mechanical systems
- Process systems, including laundry, swimming pools, kitchens, boilers, etc.
- Transportation systems, including elevators
- Lighting systems
- Desired building environmental conditions and operating schedules.

The energy auditor should use the evaluation process to determine what loads are controllable, and what control strategy is to be employed. He should then consider what other methods of controlling the loads (alternatives to the EMS) are available to produce similar control strategies. In general, the majority of the savings projected for EMS systems can be achieved by simple load controllers and time clocks with a corresponding reduction in capital investment requirements.

An EMS cannot overcome any inadequacies of the existing controls. The energy auditor must ensure that the controls in place are in a good state of repair and that they are functioning as intended. As part of the evaluation, he should determine what information he requires the system to supply and in what form and frequency he will require it.

The analysis should include projections for potential savings achievable by application of the EMS under the proposed control strategies resulting from the evaluation. Having determined potential savings, the energy auditor is then able to judge whether or not an EMS is required. If there appears to be a justification for the system, the energy auditor is faced with deciding on what type of system he requires.

EMS systems have different configurations based upon their operational characteristics. There are three basic types of system:

- Programmable load controller
- Large-scale EMS
- Facility management system.

The programmable load controller (PLC) consists of a microprocessor controller module wired to individual control relays. Typically, PLCs handle eight or sixteen loads, but more loads can be connected by grouping a series of units. Some PLCs can handle up to fifty loads and can provide limited feedback.

Large-scale EMS systems have the capabilities of PLCs, but offer more load capacity and full analog or direct digital feedback and control capabilities. Load capacities go up to 500 points, and often these systems are capable of remote communication. Remote communications capability allows a trained operating engineer or energy auditor to monitor and reprogram the operation of a building from other locations hundreds of miles away from the facility by using a portable computer terminal and regular telephone lines.

The facility management system (FMS) has all of the energy management and feedback capabilities of the large-scale EMS. In addition, it provides security and fire alarm functions and occasionally schedules equipment maintenance according to unit operating hours. The FMS is designed to serve very large single or multiple buildings from a centrally located computer. An FMS can have control capacities in the range from 100 to 8,000 points.

In the United States, the cost for an installed PLC with a capacity of 50 points would be below \$25,000. The cost of an EMS can cost between \$25,000 and \$100,000 installed. An FMS will normally exceed \$100,000 and, depending on the function and loads controlled, can reach \$1,000,000. The major categories of EMS system hardware are summarized in Exhibit 21.5.

The variation in installed costs is a function of the following:

- Number of control points
- Monitoring and control requirements
- Data transmission method(s).

The data transmission method is generally the most important cost consideration. Communication between the control relay and the central processing unit can be completed in the following ways (see Exhibit 21.6):

- Hard wiring and multiplex
- Power line carrier current
- Radio signal.

Obviously, running dedicated pairs of wire for the EMS is the most expensive approach. Hence, a number of EMS manufacturers have developed systems that permit EMS to communicate with load points by use of existing in-house wiring. Although the former approach is preferable, the majority of EMS systems in place use existing wiring wherever possible to minimize capital costs.

Savings from the use of an EMS system are hard to predict because of variations in how buildings are operated. EMS manufacturers often claim savings between 15-20

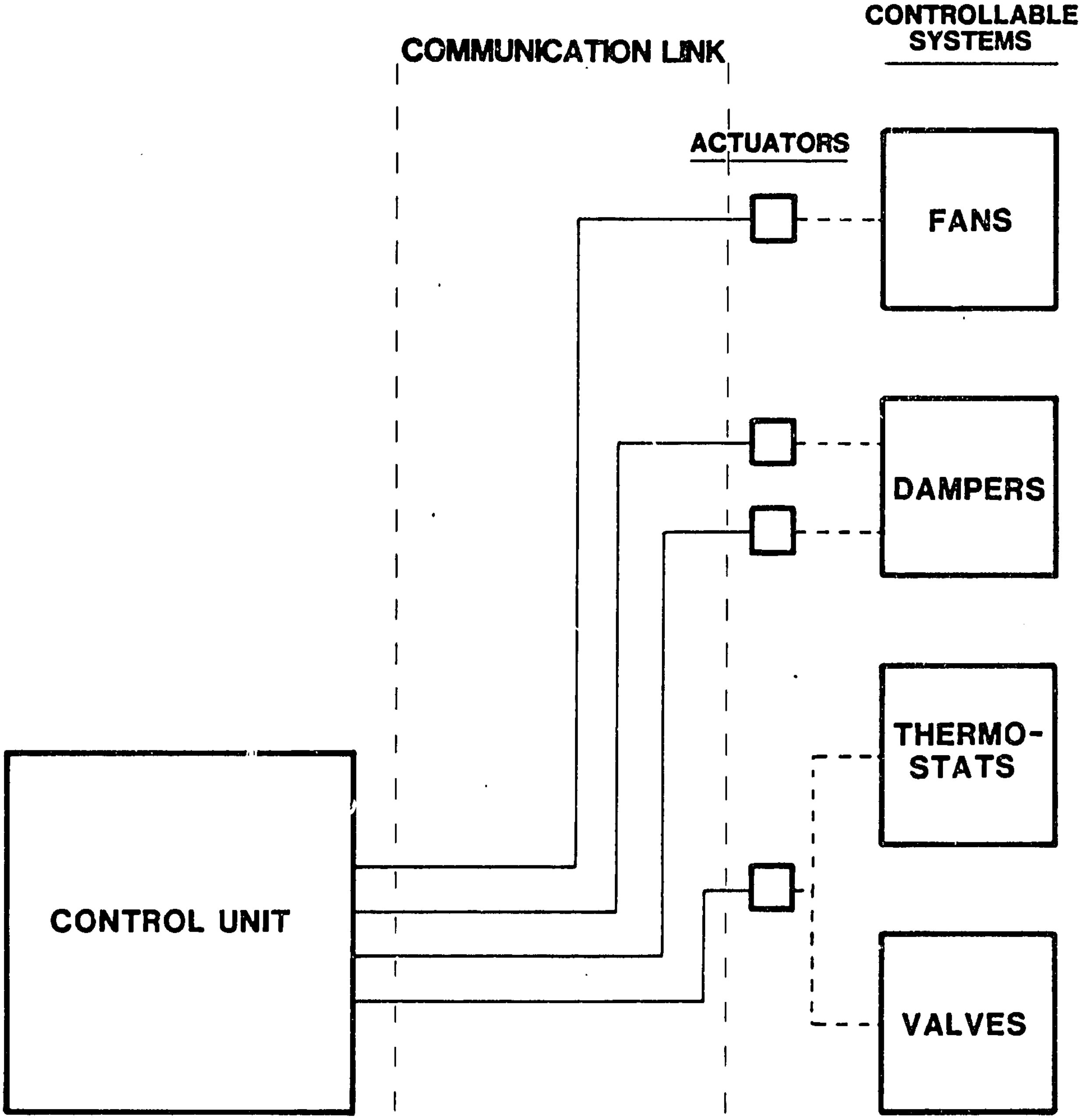
Exhibit 21.5

Major Categories of Energy Management System (EMS) Hardware

EMS category	Typical number of loads controlled	Control programs and features	Typical system installed cost per building	Typical building size (m^2)
Programmable load controllers (PLCs)	4-50	Scheduling duty cycle	\$5,000-\$25,000	2,000-10,000
Large-scale EMS	50-500	Above, plus optimized start/stop HVAC optimization, remote communications, user programming	\$25,000-\$100,000	10,000-30,000
Facility management systems (FMS)	100-8,000	Above, plus capability to serve multiple buildings fire and maintenance scheduling	\$100,000-\$1,000,000	30,000+

Exhibit 21.6

E.M.S. COMMUNICATION LINK



COMMUNICATION LINK

1. HARD WIRE & MULTIPLEX
2. LINE SIGNAL
3. RADIO CONTROL

percent of the overall energy bill. In practice, savings are more likely to be in the 5- to 10-percent range. Credit is often taken by EMS vendors for duplicating existing control strategies such as time of day control using a time clock.

SESSION 22: CORPORATE ENERGY MANAGEMENT — PROGRAM IMPLEMENTATION

The successful definition, implementation, and management of a corporate energy conservation program requires more than the mastering of the laws of thermodynamics or the use of a pitot tube. By now, it should be clear that energy conservation requires the integration of many activities of a company (e.g., plant engineering, operations, maintenance, purchasing, accounting and financial management). A corporate energy demand management and conservation program must address and integrate all these functions and, in doing so, overcome a variety of obstacles, including problems such as past operating practices and employee indifference. From the examination of successful corporate energy management programs in the United States and other countries, it is possible to identify six elements which transcend countries and industries and are present in most successful programs:

- Top management support
- Effective organization
- Adequate basis for planning
- Clearly established multiyear goals
- Continuous monitoring of results
- Effective feedback and communication.

Top Management Support

Top management support is the cornerstone of any successful program. Without active commitment from top management, the financial and human resources needed to carry out and sustain a meaningful program will generally not be available, and without adequate resources, there is no effective program. Indeed, no company program is stronger than the commitment of its top management. In the United States, the chief executive officers (CEOs) of many of the largest corporations have been directly involved in the definition and implementation of their company's conservation programs. Many of these CEOs have also been involved in the promotion of conservation outside their companies through newly-created organizations such as the Alliance to Save Energy, a private, nonprofit coalition of business, government, public interest, and labor representatives dedicated to increasing the efficiency of energy use. Top management support is needed in privately- as well as publicly-held corporations. One of the best ways to gain its support is to convince top management of the economic reasons for the need to conserve energy.

Effective Organization

Once the commitment of top management has been obtained, the successful programs are those that have developed an organization sensitive to the company's environment (e.g., the number of plants, the energy intensity of the process, the management style). Larger energy-consuming companies with several plants generally have larger and more complex organizations than smaller users with only one plant dependent on one type of fuel.

The number of personnel assigned to energy management is not always a measure of effectiveness. Once a successful program has been launched, many companies have found that they could shrink the size of their energy management organization without jeopardizing the effectiveness of the program. For example, they may rely increasingly on support from the plant maintenance staff. However, one element common to most successful programs is the presence at each location of an energy coordinator dedicated on a **full-time** basis to energy conservation activities. This energy coordinator is an engineering consultant, management consultant, public relations agent, and labor relations specialist, all in one. It is important for the energy coordinator to dedicate the majority, if not all, of his time to energy conservation activities to ensure that his other assignments do not distract him from achieving the goals that have been set for the program. Exhibit 22.1 lists some of the typical duties of an energy coordinator.

Adequate Basis for Planning

Another key element for success is a proper baseline for identifying and evaluating energy conservation opportunities. In most cases, the establishment of this baseline requires a comprehensive and detailed survey of energy uses and losses at each facility. Energy cannot be saved until it is known where it is being used and when and where it is being wasted. Some companies create a full-time audit team made up of in-house

Exhibit 22.1

Typical Duties of an Energy Coordinator

- Serves as a focal point for all energy-related information within the facility, including energy purchases, prices, and use

- Identifies where waste is occurring and quantifies losses in energy resource and cost terms

- Develops strategies, procedures and practices, and realistic targets for reduction of waste and identifies areas where more detailed study is required

- Maintains records of progress achieved

- Generates and sustains interest in energy conservation throughout the facility

- Provides technical support on energy-saving equipment and techniques for short- and long-term applications

- Keeps abreast of developments in energy conservation by maintaining contacts with external bodies such as trade associations, professional societies, and government departments engineers from several divisions who then survey all major facilities. Once the job is completed, they go back to their divisions. Others hire outside engineering consultants to conduct the audit. However, all successful programs are built on a thorough understanding of the energy use patterns, which very often requires instruments (i.e., some capital investment) to obtain measurements. The thorough <u>and</u> periodic energy auditing of major facilities forms the basis of any successful conservation program.

Clearly Established Multiyear Goals

All successful programs must translate their requirements into clear goals. These goals, defined in both financial and energy terms, must be incorporated into multiyear (e.g., 5-year) energy conservation plans. Program goals should be measurable and tough but attainable. These goals should also be flexible to compensate for variations in business activity. Some of the yardsticks used in the United States are Btu per sales dollar, Btu per standard labor-hour, and Btu per employee. The plans are blueprints for actions that detail how each goal will be reached, and are the heart of the corporate energy management program.

Each year, an action plan is prepared for energy conservation along with the company's other annual planning activities. This action plan delineates in great detail the ways and means required to achieve the coming year's goal. The financial resources and manpower requirements for the energy conservation plan are included in the company's overall capital and operating budgets.

A typical 5-year plan is updated and the planning horizon extended by 1 year each year. It covers items such as (1) energy sources for the baseline year; (2) energy availability and price factors; (3) alternative energy sources; (4) major uses of energy by functions; (5) historical results of conservation projects; (6) 5-year energy use and cost projections; (7) applications for new energy technologies; and (8) action plan for implementing energy projects.

Continuous Monitoring of Results

Another key element of a successful program is the existence of a regular (generally monthly) energy reporting system. This system is integrated into the company's traditional financial reporting system, which is submitted to corporate management. The energy reporting system reports performance along the same yardstick used to define the multi-year goals, and it relates performance to the production volume during the reporting period. This continuous monitoring is essential to identify and analyze promptly any significant variances. It also ensures regular communication of results to top management, whose ongoing commitment is essential.

Effective Feedback and Communication

Getting the message to company employees is another typical element of most successful programs. The objective of the communication program is to demonstrate company and top management support for energy conservation and to make it a vital part of the firm's business ethic. Several companies have initiated award programs (e.g., cash bonuses, prizes) for their employees. Needless to say, the best communication program is no substitute for the visible endorsement and sincere practice of energy conservation by top management.

Exhibit 22.2 is a checklist for implementing a corporate energy management program, including organizing program management, surveying energy uses and losses, implementing energy conservation actions, and developing continuing energy conservation efforts.

Exhibit 22.2

Checklist for Implementing an Energy Conservation Program

I. ORGANIZE PROGRAM MANAGEMENT

A. Inform line supervisors of:

1. The economic reasons for the need to conserve energy

2. Their responsibility for implementing energy-saving actions in the areas of their accountability

B. Establish a committee having the responsibility for formulating and conducting an energy conservation program and consisting of:

1. Representatives from each department in the plant

2. A coordinator appointed by and reporting to management

Note: In smaller organizations, the manager and his staff may conduct energy conservation activities as part of their management duties.

C. Provide the committee with guidelines as to what is expected of them:

1. Plan and participate in energy-saving surveys

2. Develop uniform record-keeping, report, and energy accounting systems

3. Research and develop ideas on ways to save energy

4. Communicate these ideas and suggestions

5. Suggest tough, but achievable, goals for energy saving

6. Develop ideas and plans for enlisting employee support and participation

7. Plan and conduct a continuing program of activities to stimulate interest in energy conservation efforts

D. Set goals in energy saving:

1. A preliminary goal at the start of the program
2. Later, a revised goal based on savings potential estimated from results of surveys

E. Employ external assistance in surveying the plant and making recommendations, if necessary

F. Communicate periodically to employees regarding management's emphasis on energy conservation action and report on progress

Exhibit 22.2 (continued)

Checklist for Implementing an Energy Conservation Program

II. SURVEY ENERGY USES AND LOSSES

A. Conduct first survey aimed at identifying energy wastes that can be corrected by maintenance or operations actions; for example:

1. Leaks of steam and other utilities
2. Furnace burners out of adjustment
3. Repair or addition of insulation required
4. Equipment running when not needed

B. Survey to determine where additional instruments for measurement of energy flow are needed and whether there is economic justification for the cost of their installation

C. Develop an energy balance on each process to define in detail:

1. Energy input as raw materials and utilities
2. Energy consumed in waste disposal
3. Energy credit for byproducts
4. Net energy charged to the main product
5. Energy dissipated or wasted

Note: Energy equivalents must be developed for all raw materials, fuels, and utilities, such as electric power, steam, etc., to express all energy sources and uses on a common unit basis (e.g., Btu, kWh).

D. Analyze all process energy balances in depth:

1. Can waste heat be recovered to generate steam or to heat water or a raw material?

2. Can a process step be eliminated or modified to reduce energy use?

3. Can an alternate raw material with lower energy content be used?

4. Is there a way to improve yield?

5. Is there justification for:

   a. replacing old equipment with new equipment requiring less energy?

   b. replacing an obsolete, inefficient process plant with a new and different process using less energy?

E. Conduct weekend and night surveys periodically

Exhibit 22.2 (continued)

Checklist for Implementing an Energy Conservation Program

F. Plan surveys on specific systems and equipment, such as:

1. Steam system
2. Compressed air system
3. Electric motors
4. Natural gas lines
5. Heating and air conditioning system

III. IMPLEMENT ENERGY CONSERVATION ACTIONS

A. Correct energy wastes identified in the first survey by taking the necessary maintenance or operation actions

B. List all energy conservation projects evolving from energy balance analyses, surveys, etc. Evaluate and select projects for implementation:

1. Calculate annual energy savings for each project

2. Project future energy costs and calculate annual dollar savings

3. Estimate project capital or expense cost

4. Evaluate investment merit of projects using measures such as return on investment, etc.

5. Assign priorities to projects based on investment merit

6. Select conservation projects for implementation and request capital authorization

7. Implement authorized projects

C. Review design of all capital projects, such as new plants, expansions, buildings, etc., to ensure that efficient use of energy is incorporated in the design

Note: Include consideration of energy availability in new equipment and plant decisions.

IV. DEVELOP CONTINUING ENERGY CONSERVATION EFFORTS

A. Measure results:

1. Chart energy use per unit of production by department

2. Chart energy use per unit of production for the whole plant

Exhibit 22.2 (continued)

Checklist for Implementing an Energy Conservation Program

3. Monitor and analyze charts of energy per unit of product, taking into consideration effects of complicating variables such as outdoor ambient air temperature, level of production rate, product mix, etc.

   a. compare energy/product unit with past performance and theoretical energy/product unit

   b. observe the impact of energy-saving actions and project implementation on decreasing the energy/unit of product

   c. investigate, identify, and correct the cause for increases that may occur in energy unit of product, if feasible

B. Continue energy conservation committee activities:

1. Hold periodic meetings

2. Ensure that each committee member is an effective communications link between the committee and the department he represents

3. Periodically update energy-saving project lists

4. Plan and participate in energy-saving surveys

5. Communicate energy conservation techniques

6. Plan and conduct a continuing program of activities and communication to maintain interest in energy conservation

7. Develop cooperation with community organizations in promoting energy conservation

C. Involve employees:

1. Service on energy conservation committee
2. Energy conservation training course
3. Handbook on energy conservation
4. Suggestion awards plan
5. Recognition for energy-saving achievements
6. Technical talks on lighting, insulation, steam traps, and other subjects
7. "savEnergy" posters, decals, stickers
8. Publicity in plant news, bulletins
9. Publicity in public news media
10. Talks to local organizations

Exhibit 22.2 (continued)

Checklist for Implementing an Energy Conservation Program

D. Evaluate program

1. Review progress in energy saving
2. Evaluate original goals
3. Consider program modifications
4. Revise goals as necessary

SOURCE: Adapted from the U.S. Department of Commerce, National Bureau of Standards, NBS Handbook 115.