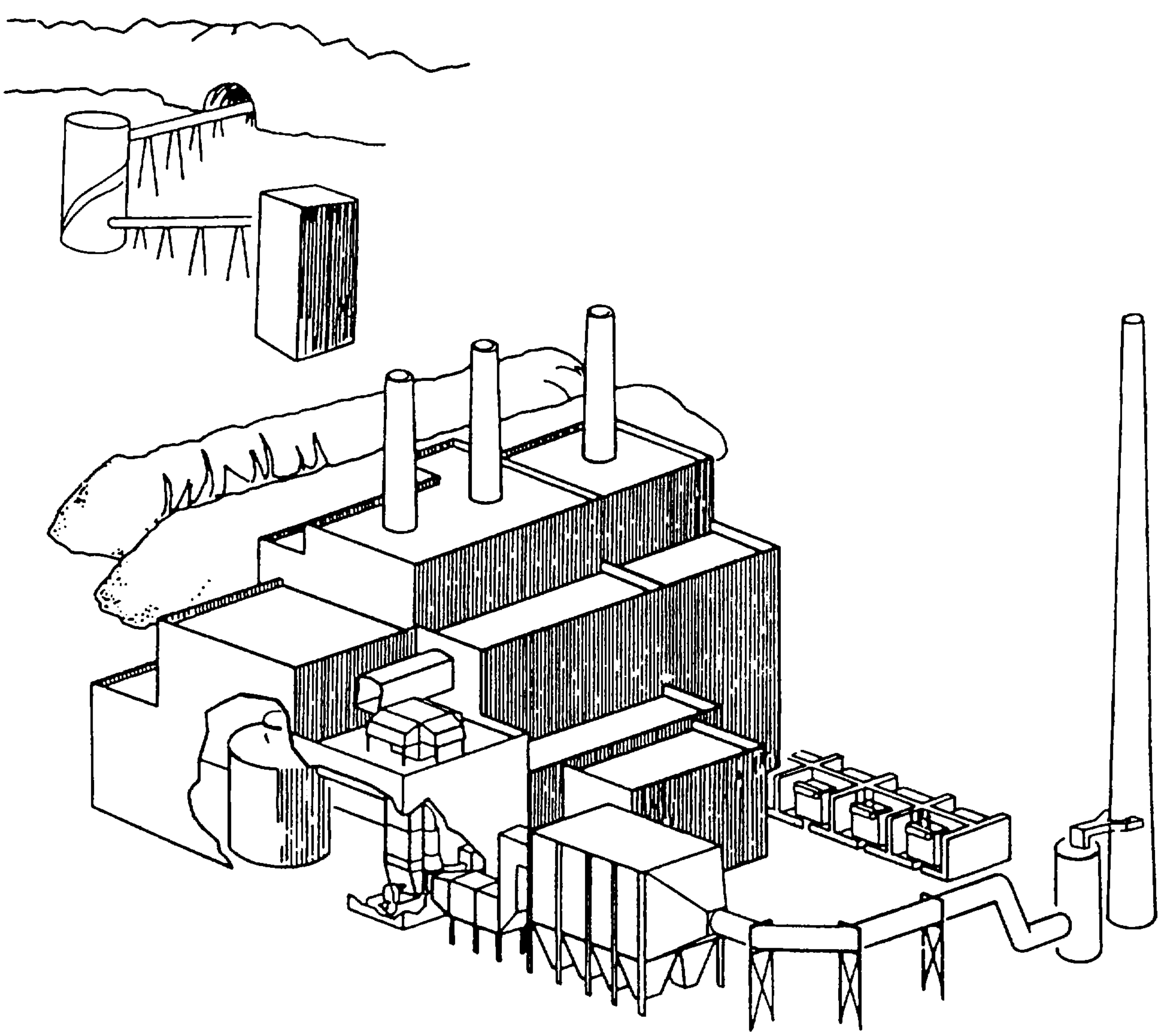
WTP286
July 1995

WORLD BANK TECHNICAL PAPER NUMBER 286
ENERGY SERIES

Clean Coal Technologies for Developing Countries

E. Stratos Tavoulareas
Jean-Pierre Charpentier



RECENT WORLD BANK TECHNICAL PAPERS

No. 205 Xie, Küffner, and Le Moigne, *Using Water Efficiently: Technological Options*

No. 206 The World Bank/FAO/UNIDO/Industry Fertilizer Working Group, *World and Regional Supply and Demand Balances for Nitrogen, Phosphate, and Potash, 1991/92–1997/98*

No. 207 Narayan, *Participatory Evaluation: Tools for Managing Change in Water and Sanitation*

No. 208 Bindlish and Evenson, *Evaluation of the Performance of T&V Extension in Kenya*

No. 209 Keith, *Property Tax: A Practical Manual for Anglophone Africa*

No. 210 Bradley and McNamara, editors, *Living with Trees: Policies for Forestry Management in Zimbabwe*

No. 211 Wiebers, *Integrated Pest Management and Pesticide Regulation in Developing Asia*

No. 212 Frederiksen, Berkoff, and Barber, *Water Resources Management in Asia, Volume I: Main Report*

No. 213 Srivastava and Jaffee, *Best Practices for Moving Seed Technology: New Approaches to Doing Business*

No. 214 Bonfiglioli, *Agro-pastoralism in Chad as a Strategy for Survival: An Essay on the Relationship between Anthropology and Statistics*

No. 215 Umali, *Irrigation-Induced Salinity: A Growing Problem for Development and the Environment*

No. 216 Carr, *Improving Cash Crops in Africa: Factors Influencing the Productivity of Cotton, Coffee, and Tea Grown by Smallholders*

No. 217 Antholt, *Getting Ready for the Twenty-First Century: Technical Change and Institutional Modernization in Agriculture*

No. 218 Mohan, editor, *Bibliography of Publications: Technical Department, Africa Region, July 1987 to December 1992*

No. 219 Cercone, *Alcohol-Related Problems as an Obstacle to the Development of Human Capital: Issues and Policy Options*

No. 220 Kingsley, Ferguson, Bower, and Dice, *Managing Urban Environmental Quality in Asia*

No. 221 Srivastava, Tamboli, English, Lal, and Stewart, *Conserving Soil Moisture and Fertility in the Warm Seasonally Dry Tropics*

No. 222 Selvaratnam, *Innovations in Higher Education: Singapore at the Competitive Edge*

No. 223 Piotrow, Treiman, Rimon, Yun, and Lozare, *Strategies for Family Planning Promotion*

No. 224 Midgley, *Urban Transport in Asia: An Operational Agenda for the 1990s*

No. 225 Dia, *A Governance Approach to Civil Service Reform in Sub-Saharan Africa*

No. 226 Bindlish, Evenson, and Gbetibouo, *Evaluation of T&V-Based Extension in Burkina Faso*

No. 227 Cook, editor, *Involuntary Resettlement in Africa: Selected Papers from a Conference on Environment and Settlement Issues in Africa*

No. 228 Webster and Charap, *The Emergence of Private Sector Manufacturing in St. Petersburg: A Survey of Firms*

No. 229 Webster, *The Emergence of Private Sector Manufacturing in Hungary: A Survey of Firms*

No. 230 Webster and Swanson, *The Emergence of Private Sector Manufacturing in the Former Czech and Slovak Federal Republic: A Survey of Firms*

No. 231 Eisa, Barghouti, Gillham, and Al-Saffy, *Cotton Production Prospects for the Decade to 2005: A Global Overview*

No. 232 Creightney, *Transport and Economic Performance: A Survey of Developing Countries*

No. 233 Frederiksen, Berkoff, and Barber, *Principles and Practices for Dealing with Water Resources Issues*

No. 234 Archondo-Callao and Faiz, *Estimating Vehicle Operating Costs*

No. 235 Claessens, *Risk Management in Developing Countries*

No. 236 Bennett and Goldberg, *Providing Enterprise Development and Financial Services to Women: A Decade of Bank Experience in Asia*

No. 237 Webster, *The Emergence of Private Sector Manufacturing in Poland: A Survey of Firms*

No. 238 Heath, *Land Rights in Côte d'Ivoire: Survey and Prospects for Project Intervention*

No. 239 Kirmani and Rangeley, *International Inland Waters: Concepts for a More Active World Bank Role*

No. 240 Ahmed, *Renewable Energy Technologies: A Review of the Status and Costs of Selected Technologies*

No. 241 Webster, *Newly Privatized Russian Enterprises*

No. 242 Barnes, Openshaw, Smith, and van der Plas, *What Makes People Cook with Improved Biomass Stoves? A Comparative International Review of Stove Programs*

(List continues on the inside back cover)

WORLD BANK TECHNICAL PAPER NUMBER 286
ENERGY SERIES

Clean Coal Technologies for Developing Countries

E. Stratos Tavoulareas
Jean-Pierre Charpentier

The World Bank
Washington, D.C.

First printing July 1995

Cover: Coal can be cleaned at several points in its "fuel chain"— at the preparation plant (top left), inside the combuster (lower left), or at the smokestack (right). Another category of clean coal technology would replace the traditional coal combuster with a coal gasifier or other conversion process. (Illustration adapted from U.S. Department of Energy, "Clean Coal Technology: The New Coal Era" [Washington, D.C., March 1992], pp.10–11.)

ISSN: 0253-7494

E. Stratos Tavoulareas is a consultant to the World Bank's Industry and Energy Department. Jean-Pierre Charpentier is a senior energy specialist in the same department.

Library of Congress Cataloging-in-Publication Data

Tavoulareas, E. Stratos, 1955–
Clean coal technologies for developing countries / E. Stratos Tavoulareas, Jean-Pierre Charpentier.
p. cm. — (World Bank technical paper; ISSN 0253-7494; no. 286. Energy series)
Includes bibliographical references.
ISBN 0-8213-3308-9
1. Coal—Developing countries. 2. Coal—Cleaning.
I. Charpentier, Jean-Pierre. II. Title. III. Series: World Bank technical paper. Energy series.
TP326.D44T38 1995
662.6'23—dc20 95-18086
CIP

ENERGY SERIES

No. 240 Ahmed, *Renewable Energy Technologies: A Review of the Status and Costs of Selected Technologies*

No. 242 Barnes, Openshaw, Smith, and van der Plas, *What Makes People Cook with Improved Biomass Stoves? A Comparative International Review of Stove Programs*

No. 243 Menke and Fazzari, *Improving Electric Power Utility Efficiency: Issues and Recommendations*

No. 244 Liebenthal, Mathur, and Wade, *Solar Energy: Lessons from the Pacific Island Experience*

No. 271 Ahmed, *Technological Development and Pollution Abatement: A Study of How Enterprises are Finding Alternatives to Chlorofluorocarbons*

No. 278 Wijetilleke and Karunaratne, *Air Quality Management: Considerations for Developing Countries*

No. 279 Anderson and Ahmed, *The Case for Solar Energy Investments*

Contents

Tables

Figures

Foreword

Linkages between energy and the environment are evident in all phases of energy production, conversion, and end use. They extend from highly localized effects—for example, at the level of the household—to the global level. On the local level in developing countries, the most serious energy-environment problems are the effects of emissions of particulate matter (dust and smoke), indoor air pollution arising from the use of biomass fuels, and the use of leaded gasoline. Volatile organic compounds generated mainly by automobilies and NO_X emissions from power plants contribute to the smog that is prevalent in large cities. In addition, the regional and transnational problem of acid rain, caused by sulfur dioxide, is also severe. Worldwide energy-related problems include the potential for global warming, caused by the increased atmospheric accumulation of greenhouse gases such as carbon dioxide and methane; stratospheric ozone depletion, much of it caused by the release of chlorofluorocarbons; and the pollution of oceans. Transport, industry, and domestic energy use are prime sources of these environmental problems, which impose serious costs for health and productivity.

To address the linkages between energy and the environment more effectively, a thematic group has been established within the Power Development, Efficiency, and Household Energy Division of the Industry and Energy Department. The group is focusing on the environmental issues in energy production, conversion, and use, including the relationship with energy efficiency. These linkages can be addressed in part through policies based on a mix of command-and-control and market-based instruments that help internalize the environmental costs of supply and use. The group is also exploring the scope for new, more efficient and environmentally friendly technologies, which need to be introduced in both the developing and industrialized countries.

This paper focuses on the status of clean coal technologies (CCTs) and on their performance, costs, and suitability for use in developing countries. CCTs have been developed primarily to address the problem of acid rain, which arises from sulfur and nitrogen oxide emissions, but some of the technologies also reduce particulates and carbon dioxide and thus help to ameliorate local pollution and global warming. CCTs have been used primarily in the industrial countries, but the developing countries also need to evaluate them in conjunction with specific projects and the process of establishing or revising environmental regulations.

The suitability of CCTs for developing countries is highly dependent on country-specific factors, such as the performance of each technology with the types of coals available in the country under consideration, present and projected levels of local pollution, local environmental regulations, and the additional financial resources required to use CCTs compared with the costs of operating conventional pulverized-coal plants. This paper makes a preliminary assessment of the suitability of CCTs that developing countries can use as a starting point for their own, more detailed assessments.

Richard Stern
Director
Industry and Energy Department

Abstract

This report on clean coal technologies (CCTs) examines their performance, costs, and suitability for use by developing countries. The paper reviews in detail for each technology key elements including basic technological features, performance levels, commercial availability, costs of operation, time required for construction, suitability for developing countries, and issues affecting deployment.

CCTs fall into three basic categories reflecting their relation to the combustion stage: *precombustion technologies* mainly involve the initial cleaning of coal by crushing and separating out pollution-generating impurities; *in situ technologies* involve altering the design and operating conditions of coal furnaces in a way that chemically or physically reduces emissions of SO_2 and NO_x; and *postcombustion technologies* also remove SO_2 and NO_x through the use of catalysts and other methods and may also scrub the gases produced by combustion and pass them through filters and precipitators to remove particulate matter. In addition, an emerging fourth category of CCTs must be noted: *advanced coal utilization technologies.* These in effect supersede the traditional stages of burning pulverized coal by using coal in integrated energy conversion processes.

The report concentrates on commercially available technologies that are currently suitable and affordable for developing countries. But it also reviews more advanced demonstration-stage technologies in anticipation of both increased regulatory requirements and a drop in the costs of such technologies that would make them both necessary and practical for developing countries sometime in the near future.

Commercially available technologies reviewed are as follows: *precombustion:* physical coal cleaning; *in situ:* low-NO_x combustion, advanced pulverized coal combustion, and power plant rehabilitation; *postcombustion:* wet and dry flue-gas desulfurization, advanced electrostatic precipitation, and bagfilters; *advanced coal utilization:* atmospheric fluidized-bed combustion.

Demonstration-stage technologies reviewed are as follows: *precombustion:* advanced cleaning methods; *in situ:* sorbent injection; *postcombustion:* duct injection, selective catalytic and noncatalytic reduction, combined SO_X / NO_X reduction, and hot-gas cleanup; *advanced coal utilization:* pressurized fluidized-bed combustion, integrated gasification combined-cycle combustion.

Given the wide use of coal in some developing countries, the paper is especially concerned to assist policymakers in choosing and justifying the use of appropriate and cost-effective CCTs. The report thus concludes with three brief chapters. The first of these discusses the relationship between environmental regulations and choice of technology; the next provides an initial screening method for evaluating relevant technologies; and the last presents conclusions and recommendations on technology choices and some notes on World Bank strategy for promoting dissemination of CCTs.

Acknowledgments

This report was developed by E. Stratos Tavoulareas (EnTEC, McLean, Virginia, USA) in close cooperation with Jean-Pierre Charpentier, of the Power Development, Efficiency, and Household Fuels Division (IENPD) of the Industry and Energy Department. Thanks are expressed to Joseph Gilling and Winston Hay (IENPD) and to Gunter Schramm (IFC) for reviewing the paper and commenting on it. The authors also would like to thank Karl Jechoutek, division chief of IENPD, for his support and guidance.

The authors appreciate the assistance of Paul Wolman, who managed the editing and production of the document; John W. Hopper, who did initial copy editing and prepared most of the illustrations; and Carole-Sue Castronuovo, who carried out the word-processing tasks.

The objective of the report is to provide World Bank staff and decisionmakers of World Bank member states with an up-to-date technical and economic overview of clean coal technologies available worldwide.

Publications and documents circulated by the Clean Coal Technology Program of the United States Department of Energy and by the Electric Power Research Institute represented a major source of documentation.

Abbreviations and Acronyms

AFBC	Atmospheric fluidized-bed combustion
Ca/S	Calcium-to-sulfur molar ratio
CCT	Clean coal technology
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FGD	Flue-gas desulfurization
HGCU	Hot-gas cleanup
IGCC	Integrated gasification combined cycle
LHV	Lower heating value
LNB	Low-NO_x burner
LSFO	Limestone with forced oxidation
NO_x	Nitrogen oxide
OFA	Overfire air
O&M	Operating and maintenance
PC	Pulverized coal
PFBC	Pressurized fluidized-bed combustion
SCA	Specific collection area
SCR	Selective catalytic reduction
SNCR	Selective noncatalytic reduction
SO_2	Sulfur dioxide

Executive Summary

Coal used for power generation accounts for more than 80 percent of the 4 billion tons of noncoking coal consumed annually worldwide, an amount that is expected to increase by an average of 2 to 3 percent per year for the next 20 years. Coal's association with local, regional, and global pollution is a cause of significant environmental concerns. Industrialized countries have adopted strict environmental regulations that have slowed their use of coal. Developing countries, on the other hand, generally do not impose or have to meet the same emission requirements, although there is mounting pressure to reduce rural and regional pollution.

During the next 10 to 20 years the use of coal for power generation will continue to increase, especially in Asia (e.g., China and India), and it will remain a significant factor in the energy supply of Eastern Europe and the Commonwealth of Independent States (CIS). This increased use will require increasing attention to minimize the environmental impacts.

Emerging clean coal technologies (CCTs) can be used effectively to reduce the environmental impact of the continued use of coal throughout the world. Although carbon emissions (CO_2) cannot be reduced significantly by these technologies, emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulates can be reduced by 50 to 99 percent. Many of the CCTs that have been developed and commercialized in industrialized countries warrant consideration for use in developing countries.

The report's main focus is on the current status of CCTs and their typical performance characteristics, costs, and suitability for use in developing countries. In addition, the report identifies the issues and barriers that need to be overcome if the technologies are to be implemented widely in developing countries. The paper is not intended as an exhaustive review of CCTs; instead, it provides selected references to more basic information on the design features of each technology.

Technologies Included in the Report

The report details the status of the following types of technologies:

- *Precombustion technologies.* These consist mainly of physical coal cleaning.
- *In situ technologies.* Low-NO_x combustion and furnace sorbent injection are the principal in situ technologies.
- *Postcombustion technologies.* These include a variety of techniques:
    - Duct injection, wet and dry scrubbers (flue-gas desulfurization; FGD) for SO_2 control
    - Selective catalytic and noncatalytic reduction for NO_x control
    - Combined SO_2/NO_x control

- Electrostatic precipitators (ESPs), bagfilters, and hot-gas cleanup for particulate control.

- *Advanced coal utilization technologies.* Again, several techniques are available:
  - Atmospheric fluidized-bed combustion (AFBC)
  - Pressurized fluidized-bed combustion (PFBC)
  - Integrated gasification combined cycles (IGCC)
  - Coal-derived fuel/electricity clean fuel coproduction.

  Advances in conventional pulverized-coal technology are also presented.

Status of Clean Coal Technologies

The important findings of the report are summarized below and in Tables 1 and 2. Table 1 lists technologies that have been demonstrated and used widely in industrialized countries. Table 2 lists technologies still in the development or demonstration phases.

- *Physical coal cleaning technologies.* These are easily adaptable to developing countries and are cost-effective in most cases. Coal cleaning reduces transportation costs as well as sulfur and particulate emissions, and it improves power plant reliability. Developing countries should be encouraged to adopt coal pricing policies that reflect the quality of the coal and its effects on power production costs, power plant reliability, and emissions.

- *Low-NO_x burners.* These should be included in the design specifications for all future power plants, and provisions should be made for overfire air ports. Such specifications increase power plant costs by less than US$5/kW and will result in significant savings when future regulations require further NO_x reductions.

- *Dry scrubbers (Table 1) and sorbent injection technologies (Table 2).* These offer attractive methods for moderate sulfur removal at relatively low costs. Further demonstration of these technologies is required in developing countries.

- *Electrostatic precipitator technology.* ESP technology has undergone significant advances. Most options have very short payback periods, and they should be considered by developing countries. Examples include the following:
  - Intermittent energization: improves performance, reduces auxiliary power
  - Flue-gas conditioning: increases the collection efficiency of ESPs
  - ESP controls and energy management systems: improve collection efficiency and reduce auxiliary power requirements.

- *Bagfilters.* Bagfilters may be required in developing countries, especially if sorbent injection, dry scrubbers, and fluidized-bed combustion are used.

- *Atmospheric fluidized-bed combustion technology.* Both circulating and bubbling types of AFBC are proven technologies at sizes below 200 MW and are well-suited for developing countries with low-grade fuels.

- *Advances in pulverized-coal techniques.* Significant advances have been made in improving conventional pulverized-coal technology. Particularly appropriate for developing countries are advanced techniques for rehabilitating power plants, which can increase the plant's unit output, life expectancy, and reliability.

Table 1 Technologies Demonstrated and Commercially Available in Industrialized Countries

Technology	*Type*	*Emissions controlled*	*Issues/barriers*	*Recommendations*
Physical coal cleaning	Pre-combustion	Sulfur and ash	Coal pricing Lack of environmental regulations	*Promote coal pricing according to coal quality* *Raise awareness of coal cleaning benefits*
Low-NO_x combustion	In situ	NO_x	Lack of environmental regulations	*Include technology in all new boiler design specifications*
Wet FGD	Post-combustion	Sulfur	Lack of environmental regulations High costs Demonstration may be needed	*Pursue FGD if environmental regulations require high SO_2 removal*
Dry FGD (commercial for low-sulfur coals)	Post-combustion	Sulfur	Lack of environmental regulations Demonstration needed	*Promote demonstration for both high- and low-sulfur coals*
Advanced ESP	Post-combustion	Particulates	Lack of environmental regulations Lack of awareness	*Promote awareness in developing countries*
Bagfilters	Post-combustion	Particulates	Lack of environmental regulations Higher cost than ESPs	*Promote selectively, especially where sorbent-based technologies are utilized*
AFBC (commercial up to 200 MW)	Advanced combustion	Sulfur and NO_x	Higher cost than PC without FGD Lack of environmental regulations	*Demonstration needed for some coals (e.g., India)*
Advanced pulverized-coal and power plant rehabilitation	In situ	Heat rate/ CO_2 improvement, as well as unit reliability	Lack of incentives for better plant performance and reliability Lack of awareness	*Promote through awareness-building and financing of life extension programs*

Note: FGD = flue-gas desulfurization; AFBC = atmospheric fluidized-bed combustion; ESP = electrostatic precipitator.

Of the technologies included in Table 2, sorbent and duct injection are particularly suitable for developing countries because of the moderate sulfur removal and low costs. However, industrialized countries do not emphasize these technologies as much as the high-sulfur removal technologies, and an initiative based in developing countries may be needed to demonstrate them and adapt them to local requirements.

PFBC and IGCC technologies also may be suitable for developing countries, but they need further demonstration. If the technology-related risks could be mitigated (e.g., through participation and risk-sharing by the equipment suppliers), demonstration projects in developing countries would be appropriate.

Table 2 Clean Coal Technologies in the Demonstration Stage

Technology	*Type*	*Emissions controlled*	*Issues/barriers*	*Recommendations*
Advanced cleaning	Pre-combustion	Sulfur and ash	Coal pricing Lack of environmental regulations Still in development	*Monitor progress in developed countries*
Sorbent injection	In situ	Sulfur	Demonstration needed in developing countries	*Promote developing country demonstration*
Duct injection	Post-combustion	Sulfur	Demonstration needed in developing countries	*Promote developing country demonstration*
SNCR (demon-strated up to 300 MW)	Post-combustion	NO_x	SNCR needs further demonstration	*Monitor experience in developed countries*
SCR (commercial for low-sulfur coals)	Post-combustion	NO_x	Lack of environmental regulations High costs Demonstration needed	*Pursue SCR if environmental regulations require high NO_x removal; demonstration needed*
Combined SO_x/NO_x	Post-combustion	Sulfur and NO_x	Early development stage	*Monitor progress in developed countries*
Hot-gas cleanup	Post-combustion	Particulates	Tied to PFBC and IGCC	*Monitor progress in developed countries*
PFBC	Advanced	Sulfur, NO_x, and CO_2	Demonstration needed	*Promote demonstration*
IGCC	Advanced	Sulfur, NO_x, and CO_2	High costs Demonstration needed	*Monitor demonstrations*

Note: Advanced coal cleaning includes advanced physical, chemical, and biological cleaning methods. SNCR = selective noncatalytic reduction; SCR = selective catalytic reduction; PFBC = pressurized fluidized-bed combustion; IGCC = integrated gasification combined-cycle.

The key characteristics of the CCTs and of the reference plant (pulverized coal with electrostatic precipitator, but without NO_x and SO_2 control) used to calculate costs are summarized in Table 3. Capital costs reflect costs in the United States and Europe, but provide a good budgetary estimate for developing countries. More detailed information on each technology is provided in chapters 2, 3, and 4 and the references.

Table 3 Characteristics of Clean Coal Technologies

Technology	*% SO_2 removal*	*% NOx removal*	*Particulate removal*	*Capital costs (US$/kW)*	
				New plants	*Retrofits*
Physical coal cleaning	10–40	None	30–60% lower fly ash	1–5 US$/ton of coal	1–5 US$/ton of coal
Advanced coal cleaning	30–70	None	Up to 70% lower fly ash	5–20 US$/ton of coal	5–20 US$/ton of coal
Low-NO_x combustion	None	30–60	None	2–10	5–25
Sorbent injection	30–60	None	None	50–80	70–100
Duct injection					
Pre-ESP	30–70	None	None	50–100	60–120
Post-ESP	70–90	None	None	80–170	100–200
Wet FGD	90–99	None	% depends on ESP-FGD configuration	120–210	150–270
Dry FGD	70–90	None	None	110–165	140–210
SNCR	None	35–60	None	5–10	10–30
SCR	None	70–90	None	50–100	50–150
Combined SO_x/NO_x	80–95	80–90	Possible by some technologies	300–400	300–400
Advanced ESP	None	None	Up to 99.9%	40–100	40–100
Bagfilters	None	None	Up to 99.9%	50–70	50–70
Hot-gas cleanup	None	None	Up to 99.9%	Not available	Not available
AFBC	70–95	50–80	None	1300–1600	500–1000
PFBC	80–95	50–80	None	1200–1500	Not available
IGCC	90–99.9	60–90	None	1500–1800	Not available

Note: Advanced coal cleaning includes advanced physical, chemical, and biological cleaning methods. ESP = electrostatic precipitator; FGD = flue-gas desulfurization; SNCR = selective noncatalytic reduction; SCR = selective catalytic reduction; AFBC = atmospheric fluidized bed combustion; PFBC = pressurized fluidized-bed combustion; IGCC = integrated gasification combined cycle.

Overall plant efficiencies of selected technologies (on a lower-heating-value basis; LHV) are presented in Table 4.

Table 4 Technology and Plant Efficiency

Technology	*Plant efficiency (%, LHV)*
PC with ESP (reference technology)	35–38
PC with wet FGD	34–37
AFBC	35–38
PFBC	38–45
IGCC	38–45

Note: PC = pulverized coal; ESP = electrostatic precipitator; FGD = flue-gas desulfurization; AFBC = atmospheric fluidized-bed combustion; PFBC = pressurized fluidized-bed combustion; IGCC = integrated gasification combined cycle.

Selection of Clean Coal Technology

The most suitable technology for each project depends greatly on the characteristics of the coal, the required environmental performance (SO_2, NO_x, and particulate control), and the cost-effectiveness. Therefore, selection of a technology should include the steps detailed below.

Step 1: Select Fuel

The key elements in fuel selection will be to determine proximate, ultimate, and ash analysis, heating value and ash softening temperatures, and variability of coal characteristics. In addition, it will be necessary to decide on the desirable fuel flexibility of the power generation facility. For example, one must determine whether the facility is to burn only one fuel throughout its operating life or whether it should be capable of burning other fuels as well.

Step 2: Determine Environmental Requirements

Environmental requirements may be dictated by national, regional, or local regulations, and they may be either *emissions (effluent or point-source) standards* or *ambient air quality standards.* Emissions standards apply directly to the new source (power generation facility). If air quality standards are used, the emission inventory, dispersion, and impact of the added pollutants on air quality must be assessed, and a maximum allowable level will be determined for each major pollutant (SO_2, NO_x, and particulates) based on applicable environmental standards.

Step 3: Evaluate Technologies

An evaluation of the technology should consider the following criteria:

- *Suitability of the technology to characteristics of the coal.* For example, entrained gasification is not suitable for many Indian coals without significant reduction of their high ash content (coal cleaning).

- *Technology readiness.* The technology should be in use in a few (at least five) commercial-size plants and should have demonstrated its performance, cost-effectiveness, and reliability.
- *Environmental requirements.* The environmental criteria of the project must be satisfied, and technologies not meeting the requirements screened out.
- *Cost-effectiveness.* Finally, the most cost-effective technologies that meet the above requirements should be selected (in many cases, several technologies will qualify).

Step 4: Perform Site-Specific Assessment If Needed

Consideration of site requirements is particularly important when more than one process will satisfy technological, environmental, and cost criteria.

A Hypothetical Selection Case

A hypothetical example of the selection process is provided below.

Step 1

Power Company X plans to build a 400 MW base-load power plant. Four alternative plant sites and three coals (see Table 5) have been identified. Coal A is a high-ash indigenous coal cleaned to reduce ash and sulfur content; coal B is a high-ash/high-sulfur indigenous coal; and coal C is a low-ash/low-sulfur imported coal.

Step 2

Review of the federal and local environmental regulations identified the following requirements for each of four possible power plant sites:

- Site #1: 95 percent particulate removal
- Site #2: 95 percent particulate removal and less than 800 ppm SO_2 (1.85 lbs SO_2 /MBtu)
- Site #3: 95 percent particulate removal, less than 520 ppm SO_2 (1.2 lbs SO_2 /MBtu), and 50 percent NO_x removal
- Site #4: 95 percent particulate removal, less than 90 ppm SO_2 (0.2 lbs SO_2 /MBtu), and 80 percent NO_x removal.

Step 3

For site #1, because no SO_2 and NO_x emission removal requirements are in force, the least-cost option is the pulverized-coal plant with electrostatic precipitators (ESP) firing the lowest-cost coal (coal B). The capital costs of this option are $1,000/kW with a coal price of $20 per ton, giving a levelized cost of electricity of 46 mills/kWh (Table 6).

For site #2, Coal A (cleaned to reduce the sulfur content to 1.5 percent) burned in a pulverized-coal plant equipped with ESP satisfies the environmental requirements of Site #2 and is the least-cost option. Sulfur emissions from such a plant are 775 ppm SO_2 (1.80 lbs SO_2 /MBtu). Coal cleaning adds $4 per ton in the cost of the coal ($24 per ton delivered to the plant) and results in 47 mills/kWh of levelized cost of electricity (Table 6).

For site #3, four technology types satisfy the environmental requirements: pulverized-coal plant with ESP firing imported low-sulfur coal (coal C); pulverized-coal plant with ESP and wet FGD firing coal A; atmospheric fluidized-bed combustion with bagfilter firing coal B; and pressurized fluidized-bed combustion with hot-gas cleanup firing coal B. Although the capital costs of these technologies for Site #3 vary (see Table 6), the levelized costs range from 53 to 58 mills/kWh (which is within the level of accuracy of the estimates).

Table 5 Coal Types and Characteristics for Hypothetical Case

Measure	*Coal A (high-ash/medium-sulfur)*	*Coal B (high-ash/high-sulfur)*	*Coal C (low-ash/low-sulfur)*
Proximate analysis			
Volatiles (%)	16.8	12.8	44.0
Fixed carbon (%)	52.1	41.1	48.3
Moisture (%)	4.5	4.0	15.0
Sulfur (%)	1.5	3.3	1.0
Ash (%)	25.1	38.8	7.7
Heating value (Btu/lb)	8,200	7,505	10,270
(Kcal/Kg)	(4,550)	(4,165)	(5,700)
Uncontrolled SO_2	775	1,890	430
emissions ppm (lbs/MBtu)	(1.80)	(4.4)	(1.0)
Coal price ($/ton)	24	20	45[a]

[a]Imported coal prices range from 30 to 60$/metric ton. See IEA, "Coal Information 1992"; and Jechoutek and others, "Steam Coal for Power and Industry/Issues and Scenarios," World Bank, October 1992.

Step 4

In the case of sites #1 and #2, a clear technology choice emerges. However, in the case of site #3, the selection of the most appropriate technology will depend on other site-specific considerations, advantages, and disadvantages. For example:

- Although imported coal has the lowest levelized cost, it may be eliminated because of its adverse impacts on foreign exchange requirements.

- If it is desirable to burn coal B as well as coal A, the design of the PC with wet FGD plant will need to be modified, adding to its capital and levelized costs, and making it less competitive. Also, the pulverized-coal plant may not be able to burn coal with an ash content greater than 30 to 40 percent and still meet the environmental requirements.
- AFBC can burn other coals, including low-quality/lower-cost coals, but it generates more solid waste.
- PFBC has characteristics similar to AFBC, but it has higher technical risks because it is still in the demonstration stage.

The importance of these factors for Site #3 needs to be evaluated in more detail before a final selection is made regarding the most suitable and cost-effective technology. Therefore, a site-specific feasibility study is required.

Table 6 CCT Options for Hypothetical Case

Technology option	*Emission requirement*	*Capital cost ($/kW)*	*Plant efficiency (%, LHV)*	*Coal price ($/ton, delivered)*	*O&M cost (mills/ kWh*	*Fuel cost (mills/ kW)*	*Levelized cost (mills/ kW)*
PC with ESP (coal B)	95% particulate removal	1,000	36	20	9	11	46
PC with ESP + coal cleaning (coal A)	1.85 lbs SO_2/MBtu, 95% particulate removal	1,000	36	24	9	13	47
PC with ESP and low-NO_x burners (coal C)	1.2 lbs SO_2/MBtu, 50% NO_x, 95% particulate removal	1,000	36	45	9	19	53
PC with ESP, low-NO_x burners and wet FGD (coal A)	1.2 lbs SO_2/MBtu, 50% NO_x, 95% particulate removal	1,200	35	24	10	14	54
AFBC with bagfilter (coal B)	1.2 lbs SO_2/MBtu, 50% NO_x, 95% particulate removal	1,400	36	20	11	11	58
PFBC with hot-gas cleanup (coal B)	1.2 lbs SO_2/MBtu, 50% NO_x, 95% particulate removal	1,350	42	20	11	9	55
IGCC (coal C)	0.2 lbs SO_2/MBtu, 80% NO_x, 98% particulate removal	1,600	41	45	12	17	70

Note: Levelized cost is calculated using the following assumptions: capacity factor = 65 percent; discount rate = 12 percent; construction duration = 4 years; plant life = 30 years. PC = Pulverized coal; ESP = electrostatic precipitator; FGD = flue-gas desulfurization; AFBC = atmospheric fluidized bed combusion; PFBC = pressurized fluidized-bed combusion; IGCC = integrated gasification combined cycle.

For site #4, integrated gasification combined cycle (IGCC) using coal C is the only technology that meets the SO_2 and NO_x removal requirements. Coal C is selected because it is more suitable for the entrained gasification processes, which are closer to commercialization. Coals with high ash content (above 15 to 20 percent) require fluidized-bed gasification processes, which have not been fully demonstrated.

Recommendations

In general, for the present and near-term future environmental regulations of most developing countries, the most suitable and cost-effective technologies are the following:

- Coal cleaning
- Sorbent injection
- Dry scrubbers
- Atmospheric fluidized-bed combustion
- Electrostatic precipitators.

For NO_x control, low-NO_x burners provide a low-cost solution and should be adopted by all new power plants. Also, significant advances have been made in ESP technology and pulverized-coal combustion that should be considered for both new and retrofit applications. For other clean coal technologies, however, a site-specific technology screening, including a risk assessment, is recommended.

1

Introduction

This report seeks to provide a general update on clean coal technologies, and, in particular, on their performance, costs, and suitability for developing countries. The technologies are categorized broadly according to their location relative to the boiler/combustion stage:

- *Precombustion technologies.* These involve mainly coal cleaning.
- *In situ technologies.* These comprise low-NO_x combustion and furnace sorbent injection.
- *Postcombustion technologies.* These include duct injection; wet and dry scrubbers for SO_2 control; selective catalytic and noncatalytic reduction for NO_x control; combined SO_2/NO_x control; and electrostatic precipitators, bagfilters, and hot-gas cleanup for particulate control.
- *Advanced coal utilization technologies.* These include atmospheric and pressurized fluidized-bed combustion, integrated gasification combined cycle, and coproduction of coal-derived fuels and electricity. Advances in pulverized-coal plant components, thermodynamic cycle, and plant rehabilitation are also presented. The description of the pulverized-coal advances is not exhaustive; rather, it is intended to raise the level of awareness of this technology.

The report provides a summary of the key elements associated with each technology, including a brief description of the technology, along with some discussion of its performance, commercial availability and costs of operation, construction time, suitability for developing countries, and issues affecting deployment. The capital and O&M costs reflect mostly costs in the U.S. and Europe, but they are applicable to developing countries as budgetary cost estimates for technology screening purposes. Annex A provides more detailed information on selected technologies.

The main report is organized into seven chapters, including this introduction. Chapter 2 reviews the status of precombustion and in situ coal technologies. Chapter 3 covers postcombustion technologies, and chapter 4 discusses advanced lower-polluting technologies. Chapter 5 is devoted to the link between technology selection and environmental requirements, especiall ertains to developing countries. Chapter 6 provides an example of a method hat can be used to evaluate clean coal technologies on the basis of diffı riteria, including technology readiness, characteristics of local coals, environm gulations, costs, and indigenous capability. Chapter 7 presents conclusions and rec ıdations.

Two annexes are also inclı Annex A provides a summary of the environmental regulations of industria untries and developing countries. Annex B comprises several lists of equipment rs. It is not complete, however, because it includes only the organizations for wł ormation was readily available—mainly the U.S. suppliers.

Table 1.1 provides a guide to tl s information on specific technologies.

Table 1.1 Clean ›al echnology Text Locator

Technology	SO_2	NO_x	CO_2	*Particulates*	*Report location (page)*
Coal cleaning	x			x	13
Low-NO_x combustion		x			16
Sorbent injection	x				19
Duct injection	x				23
Wet FGD (scrubbers)	x				26
Dry FGD (spray dryers)	x				30
SNCR		x			32
SCR		x			34
Combined SO_x/NO_x	x	x			36
Electrostatic precipitators				x	39
Fabric filter (baghouse)				x	40
Hot-gas cleanup				x	41
Atmospheric fluidized-bed combustion	x	x			45
Pressurized fluidized-bed	x	x	x		48
Integrated gasification	x	x	x		50
Clean coal-derived fuels	x	x	x		54
Advances in pulverized-coal			x		54

Note: FGD = flue-gas desulfurization; SNCR = selective noncatalytic reduction; SCR = selective catalytic reduction; NO_x = nitrogen oxides; SO_x - sulfur oxides.

2

Precombustion and In Situ Technologies

Precombustion technologies basically involve "cleaning" of selected impurities—such as ash, sulfur, and moisture—from the coal before it reaches the furnace. In situ technologies, on the other hand, involve either pollution-reducing modifications to the design and operating conditions of the burner system or injection of a "sorbent" (a substance that takes up and holds impurities by adsorption or absorption) at some phase of the combustion process.

Coal Cleaning

Coal cleaning originally focused on removing ash and moisture from coal to reduce transportation costs and improve the power plant efficiency. More recently, however, coal cleaning in the industrialized countries has focused on removing sulfur to reduce acid-rain-related emissions. Coal-cleaning methods may be classified into conventional physical cleaning and various advanced cleaning methods, including advanced physical cleaning, aqueous phase pretreatment, selective agglomeration, and organic phase pretreatment.

Of these alternatives, conventional physical cleaning is widely used, well proven, and highly suitable for use by developing countries. The advanced cleaning methods are mostly still in the development or demonstration stages, are noted in a brief section below.

Conventional Physical Cleaning

Conventional coal cleaning relies chiefly on gravity-based separation of inerts (ash) and sulfur compounds before the coal is pulverized and introduced into the steam generator (boiler) for combustion.

Technology. Conventional cleaning usually begins with crushing of the coal to a 50 mm maximum diameter, followed by screening into coarse, intermediate, and fine particles. Crushing liberates ash-forming minerals and nonorganically bound sulfur (e.g., pyrites [FeS_2]). Grinding into smaller particles results in higher separation. Because mineral matter has a higher density than organic-rich coal particles, it can be separated from the coarse and intermediate particles of coal by jigs, dense-medium baths, cyclone systems, and concentrating tables (see Table 2.1).

Table 2.1 Conventional Physical Coal Cleaning Technologies

Technology type	*Process*
Crushing	Grinders pulverize coal, which is then screened into coarse (≤ 50 mm diameter), intermediate, and fine (< 0.5 mm) particles. The crushing liberates the nonorganically bound mineral particles from the coal. Because these mineral particles are denser than the organically rich coal, they can be separated from the coal by further processing (see next items).
Jigs (G)	For coarse to intermediate particles
Dense-medium baths (G)	For coarse to intermediate particles
Cyclones (G)	For coarse to intermediate particles
Froth flotation (G)	For fines; relies on the different surface properties of ash (hydrophilic) vs. coal (hydrophobic); high potential, but current technologies do not handle the small particles efficiently.

Note: G = Gravity-(density)-based separation.

The fines (particles smaller than 0.5 mm in diameter) can be separated by the froth flotation technique, which exploits surface differences between coal and ash (coal's surface is hydrophobic, whereas ash's surface is hydrophilic). Unfortunately, although the potential for cleaning the coal fines is greater than for cleaning the coarse and intermediate coal particles, current technologies do not handle the fines efficiently.

Physical cleaning cannot remove organically bound sulfur that requires chemical or biological methods. Thus, the the larger the percentage of organically bound sulfur in the coal, the lower the percentage of sulfur that can be removed by physical methods.

Performance. Ash removal can reach 60 percent; total sulfur removal is 10 to 40 percent, increasing in tandem with a rising percentage of pyritic (mineral) sulfur in the coal. Weight recovery (the percentage of coal retained) is 60 to 90 percent, and thermal recovery (percent of heating value retained) is 85 to 98 percent.

Availability. The following points describe the commercial conditions under which conventional coal cleaning is available today:

- *Technology readiness.* Conventional coal cleaning methods are commercially available throughout the world.
- *Suppliers.* A list of equipment suppliers is provided in Annex B, Table B.1.
- *Cost-effectiveness.* The cost of physical cleaning varies from US$1 to US$10/ton, depending on the coal quality, the cleaning process used, and the degree of cleaning desired. In most cases, cleaning costs range from US$1 to US$5/ton.

Selection of the most appropriate physical coal cleaning method and the choice of the level of cleaning desired involves balancing advantages and disadvantages (see Table

2.2). It also involves considerations such as environmental regulations (sulfur-removal requirements) and the cost of cleaned coal relative to that of naturally occurring coal of the same quality.

Table 2.2 Advantages and Disadvantages of Physical Coal Cleaning

Advantages	*Disadvantages*
10 to 40 percent lower SO_2 emissions	Coal grinding is energy-intensive.
Higher pulverizer and boiler availability (estimated: 1 percent improvement in availability for every 1 percent decrease in ash content)	2 to 15 percent energy loss during cleaning.
	Water-based coal cleaning methods add moisture to the coal, which reduces boiler and power-plant efficiency.
Lower maintenance costs (less wear and tear on coal preparation equipment and boiler)	
Less boiler slagging and fouling	
Lower dust loading of ESP/bagfilter	
Lower transportation costs (applicable to cleaning at the mine only)	

Construction. Building of the necessary equipment requires from 1 to 2 years (including design, manufacture, and construction).

Suitability. Although the suitability of a technology requires an evaluation of the specific characteristics of each coal (e.g., percentage of pyritic vs. organically bound sulfur), most coals in developing countries can be cleaned with conventional physical cleaning methods. These technologies may need to be modified, but most developing countries, with some initial external support, have the know-how and infrastructure to accept, adapt, design, manufacture, and use these technologies.

Deployment. Most developing countries have no incentive to clean coal because the price of coal does not vary with quality or with impact on power plant performance. Also, present environmental regulations in most developing countries do not encourage sulfur reduction.

Advanced Coal Cleaning

The advanced coal cleaning methods (advanced physical, aqueous, and organic phase pretreatment and selective aglomeration) are at the early commercialization or development stages, and their cleaning effectiveness and economic attractiveness are largely untested. Because this report focuses on the near-term applicability of CCTs to developing countries, the advanced methods are merely noted in passing (see Table 2.3).

Table 2.3 Advanced Coal Cleaning Technologies

Technology type	*Process*
Advanced physical cleaning	Advanced froth flotation (S) Electrostatic (S) Heavy liquid cycloning (G)
Aqueous phase pretreatment	Bioprocessing Hydrothermal Ion exchange
Selective agglomeration	Otisca[a] LICADO[a] Spherical Agglomeration Aglofloat[a]
Organic phase pretreatmentt	Depolymerization Alkylation Solvent swelling Catalyst addition (e.g., carbonyl) Organic sulfur removal

Note: G = gravity-(density)-based separation; S = surface-effect-based separation.
[a]Trade names for commercial processes.

In Situ Technologies

In situ technologies include both NO_x and SO_2 control methods. NO_x control focuses mainly on modification of the design and operating conditions of the burner (combustion system). In situ SO_2 control technologies utilize injection of a sorbent (usually limestone) to capture the sulfur and remove it as a dry, solid by-product.

Low-NO_x Combustion Technologies

NO_x emissions have been linked to acid rain, photochemical smog, and tropospheric ozone (greenhouse effect). This has led to establishment of regulatory measures and to development of technologies to reduce NO_x emissions from existing and new power plants. Two general techniques are used to reduce NO_x emissions. The first involves modification of the combustion process (staged combustion) and includes low-NO_x burners (with and without overfire air [OFA]) and gas or coal reburning; these methodologies are described in this section. The second type of NO_x reduction strategy involves postcombustion removal and includes selective noncatalytic NO_x reduction (SNCR), selective catalytic reduction (SCR), and combined SO_2/NO_x removal; these methods are discussed in chapter 3. Both types are shown in Figure 2.1.

Technology. Low-NO_x burners (LNBs) are designed to "stage" combustion (see Figure 2.2). In this technology, a fuel-rich combustion zone is created by forcing additional air to the outside of the firing zone (auxiliary air) and by delaying the combustion of coal. Reduction of 30 to 55 percent of NO_x can be achieved with low-NO_x burners. Advanced stage combustion technologies use overfire air and gas or coal reburning to achieve even greater reductions of NO_x.

Figure 2.1 Combustion and Postcombustion NO_x Control Options

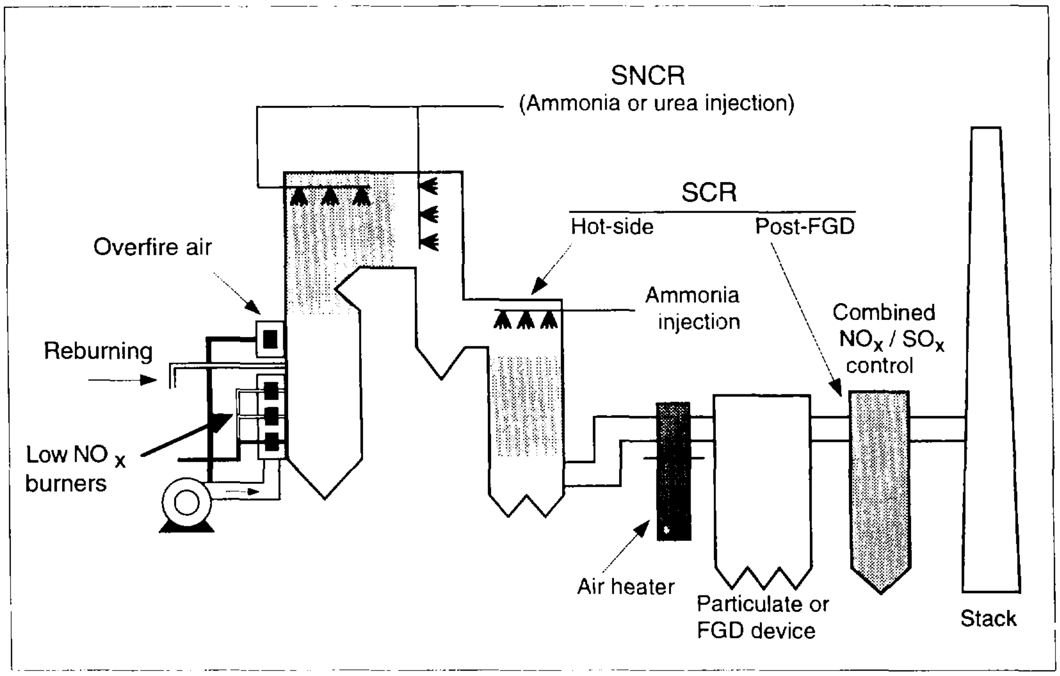


Figure 2.1 shows both combustion and postcombustion NO_x controls. The left side of the figure shows technologies used in the burner—low-NO_x burners, overfire air, and reburning. The top and right sides of the figure show technologies used downstream of the boiler—SNCR, SCR (hot-side and post-FGD), and combined NO_x/SO_x technologies.

Note: SCR = selective catyalytic reduction; SNCR = selective noncatalytic reduction; FGD = flue gas desulfurization.

Figure 2.2 Conceptual Design of a Low-NO_x Burner

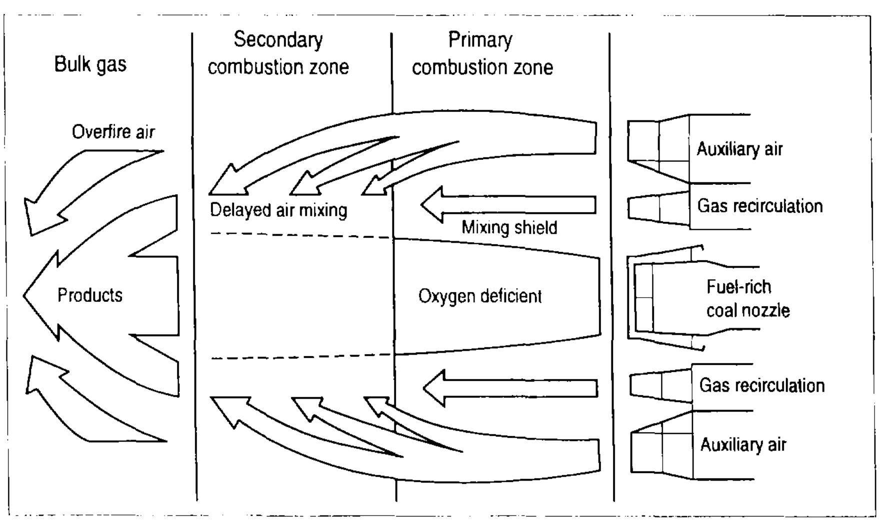


Figure 2.2 shows the introduction of auxiliary air outside the coal nozzle (right side of figure), which creates an oxygen-deficient region and delayed combustion in the primary and secondary combustion zones (center). Overfire air (left) competes the combustion.

OFA systems introduce 10 to 25 percent of the combustion air above the main combustion zone, creating a fuel-rich combustion. LNB plus OFA can reduce NO_x by 40 to 60 percent, and gas or coal reburning can reduce NO_x by up to 60 to 70 percent.

In reburning, the rate of flow of coal into the main combustion zone is reduced by up to 20 percent; it is replaced by an equal heat input of natural gas or coal introduced above the main combustion zone (see Figure 2.1). The NO_x reduction potential of these three low-NO_x burner systems, as well as the associated capital costs, operating and maintenance impacts, and required outage for retrofit are summarized in Table 2.4.

Table 2.4 Key Characteristics of Low-NO_x Burner Technologies

	Costs (US$/kW)		*NO_x reduction*	*O&M impacts (mill/kWh)*		*Retrofit outage*
Technology	*Retrofit*	*New boiler*	*(percent)*	*Retrofit*	*New boiler*	*(weeks)*
LNB	5 – 10	1 – 3	30 – 55	< 1	None	3 – 5
LNB + OFA	10 – 25	3 – 10	40 – 60	approx. 1	None	4 – 9
Reburning	20 – 50	10 – 30	50 – 70	1 – 5	1 – 4	5 – 10

Note: LNB = low-NO_x burner; OFA = overfire air.

Availability. The following points describe the commercial conditions under which low-NO_x combustion technology is available today.

- *Technology readiness.* LNB and LNB plus OFA are being used commercially in Europe, Japan, and the United States. New boilers in industrialized countries all use low-NO_x burners, and retrofits of old boilers are being legislated in many cases. In the United States, plants with a total of 51,000 MW of generating capacity were retrofitted with low-NO_x burners during 1992–94. Reburning has been demonstrated in six U.S. utility boilers ranging from 40 to 180 MW.
- *Suppliers.* A partial list of suppliers is provided in Annex B, Table B.2.
- *Cost-effectiveness (see Table 2.4).* The costs of retrofitting existing boilers with low-NO_x burners range from US$5/kW for LNB to US$50/kW for reburning. The capital costs of incorporating such systems into new boilers are a fraction of the costs for retrofitting existing boilers. For example, incorporating a LNB + OFA into a new boiler adds only US$3 to 10/kW, whereas retrofitting an existing boiler may cost up to US$25/kW. The cost-effectiveness (in terms of US$/ton of NO_x removed) depends on the capital costs, O&M impact, and required NO_x reduction. Typical ranges of cost-effectiveness are as follows:
  - LNB: 100 to 200 US$/ton NO_x removed
  - LNB + OFA: 200 to 400 US$/ton NO_x removed
  - Reburning: 300 to 600 US$/ton NO_x removed.

Construction. As shown in Table 2.3, retrofitting an existing boiler with low-NO_x burner technologies requires a unit outage of 3 to 10 weeks, depending on the technology.

The use of low-NO_x burners is not expected to affect the design, manufacture, and construction of new boilers.

Suitability. Low-NO_x burner technologies are suitable for developing countries. Minor adaptations may be required to accommodate the unique characteristics of some coals (especially in countries such as China and India), but these adaptations can be part of commercial projects; no full-scope technology demonstration project is needed.

Most developing countries have the capability (manufacturing facilities) to acquire the technology and to manufacture low-NO_x systems locally, although transfer of technology know-how is needed.

Deployment. Lack of environmental regulations requiring NO_x emission control is the main reason for the limited use of these technologies in developing countries. Developing countries should include low-NO_x burners in new boilers (because the incremental costs are minimal), and either include overfire air systems or make provisions in boiler design for easy incorporation of overfire air in the future. Reburning may be particularly attractive where natural gas is available at the power plant site, and required NO_x emissions are below 400 ppm.

Sorbent Injection for SO_2 Control

Technology. SO_2 may be removed by injecting a sorbent (lime, limestone, or dolomite) into the combustion gases. Depending on the location of the sorbent injection point, the technologies are classified as follows (see Figure 2.3):

- *Furnace sorbent injection.* The injection point is above the burners or in the backpass before the air heater.
- *Duct injection.* Injection after the air heater.

Furnace injection is described here; duct injection is described in chapter 3.

Furnace sorbent injection involves injection of the sorbent, together with combustion air, above the combustion zone (preferably where the gas temperature is approximately 1,200° C, or 2,200° F), together with combustion air, through special injection ports. Alternatively, the sorbent may be injected before the economizer, where the gas temperature is approximately 540° C (1100° F).

The sorbent decomposes into lime, which reacts in suspension with SO_2 to form calcium sulfate ($CaSO_4$). The calcium sulfate, unreacted sorbent, and fly ash are removed at the particulate control device (either an electrostatic precipitator or bagfilter) downstream from the boiler. Sorbent injection, however, affects the properties of the particulates (higher resistivity and different size and morphology than derived from pulverized coal without SO_2 control), which in turn adversely affects the performance of the electrostatic precipitator (ESP). Gas conditioning (humidification or ammonia injection) may be needed to maintain the ESP's performance.

Figure 2.3 Sorbent Injection Points

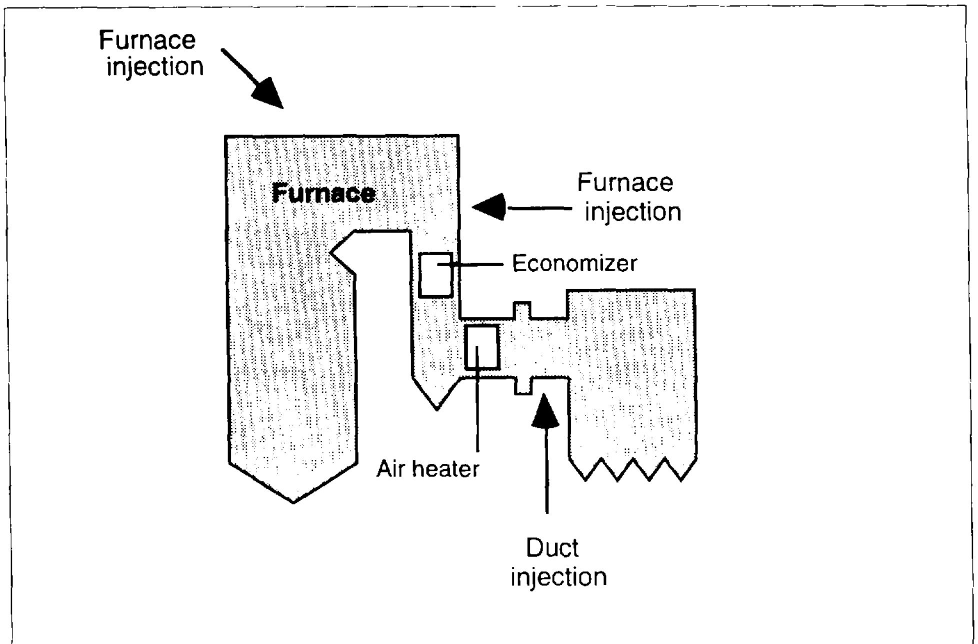


Figure 2.3 shows the points at which sorbent can be injected: at the top of the furnace or at the backpass cavity (right side of furnace) upstream of the economizer (furnace injection), or (bottom right) downstream of the air heater (duct injection).

Performance. SO_2 removal is 30 to 60 percent (with a calcium-to-sulfur [Ca/S] molar ratio of 2:1). Sorbent injection before the economizer is expected to require less sorbent (Ca/S molar ratio of 1:1), but this still must be demonstrated on a large scale. The technology is suitable for both new and retrofit applications.

Availability. The following points describe the commercial conditions under which sorbent injection technology is available today.

- *Technology readiness.* The technology is in the demonstration phase; several large-scale demonstration projects have been completed in the United States, including Ohio Edison's Edgewater #4 (104 MW wall-fired unit) and Illinois Power's Hennepin #1 (71 MW) and in Europe. Other demonstrations (e.g., in Springfield, Illinois, a 33 MW cyclone-fired boiler) are still under construction. A number of issues must be addressed before the technology is considered fully demonstrated and commercially available:
  - Sorbent efficiency—the sorbent utilization needs to be improved to enhance the economic attractiveness of the technology.
  - Furnace injection adversely affects slagging.
  - Injection before the economizer increases fouling of it and the air heater.
  - Sorbent injection decreases electrostatic precipitator (ESP) performance.

- *Suppliers.* A list of suppliers is provided in Annex B, Table B.3.
- *Cost-effectiveness.* Sorbent injection is simple and has lower capital and operating costs than scrubbers, but it has limited SO_2 removal (30 to 60 percent) capability. Other advantages of the technology are that it requires very little space, uses readily available additives (sorbent), and is easy to operate and maintain. Capital costs are 70 to 120 US$/kW (Kataoka 1993); variable operating costs are 3 to 7 USmills/kWh (DePero and others 1993).

In cases where low SO_2 removal (30 to 60 percent) is adequate, sorbent injection may be the technology of choice.

Construction. For retrofit projects, the unit must be off-line for 4 to 10 weeks. Construction schedules for new boilers are not expected to be affected significantly by the incorporation of sorbent injection into the design, however.

Suitability. This technology is particularly suitable for short- and intermediate-term (5 to 10 years) applications in developing countries for the following reasons:

- Environmental regulations in most developing countries do not require very high SO_2 removal; 40 to 60 percent removal may be adequate.
- Sorbent injection is a simple process with low capital and O&M costs.
- Sorbent injection systems are easy to operate and maintain.
- The technology is particularly suitable for retrofit applications.

Deployment. Deployment of sorbent injection in developing countries will require further demonstration of its performance and economic attractiveness. This can be achieved through more demonstrations and commercial projects in developed countries, and through one or two demonstration projects in developing countries. Because such projects require 3 to 5 years to be completed, wide application of this technology in developing countries is not expected before the end of the century.

3

Postcombustion Technologies

Postcombustion technologies include methods for controlling SO_2, NO_x, and particulates and may involve treating these separately or in combination. This chapter describes the following postcombustion technologies:

- *SO_2 control.* The main technologies are duct (sorbent) injection, wet FGD (wet scrubbers), and dry FGD (spray dryers).
- *NO_x control.* These include selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR).
- *Combined SO_2 and NO_x control.* Such technologies include adsorption/regeneration, flue-gas irradiation, wet scrubbing additive for NO_x removal, gas/solid catalytic operations, electrochemical processes, and dry alkali processes.
- *Particulate removal.* The principal methods are electrostatic precipitators (ESP), bagfilter (baghouse) technologies, and hot-gas cleanup technologies.

SO_2 Control Technologies

Duct Injection

Duct injection processes are of two types: pre-ESP sorbent injection and post-ESP sorbent injection. These are discussed together below.

Technology. Pre-ESP sorbent injection is similar to furnace sorbent injection in that it requires similar hardware. Post-ESP sorbent injection also requires a reaction vessel (absorber), and it also requires either an ESP upgrade or the addition of a fabric filter to remove particulates resulting from the recycling of the sorbent (see Figure 3.1).

In both the pre- and post-ESP sorbent injection methods, the flue gas is cooled to the "approach temperature" by water conditioning (see Figure 3.1). In the absorber, a calcium solution, $Ca(OH_2)$, and recirculated sorbent are injected into the flue gas. The reaction by-products—calcium sulfate ($CaSO_4$), calcium chloride ($CaCl_2$), fly ash, and unreacted sorbent—are removed by a downstream fabric filter.

Figure 3.1 Post-ESP Duct Injection Process Flow

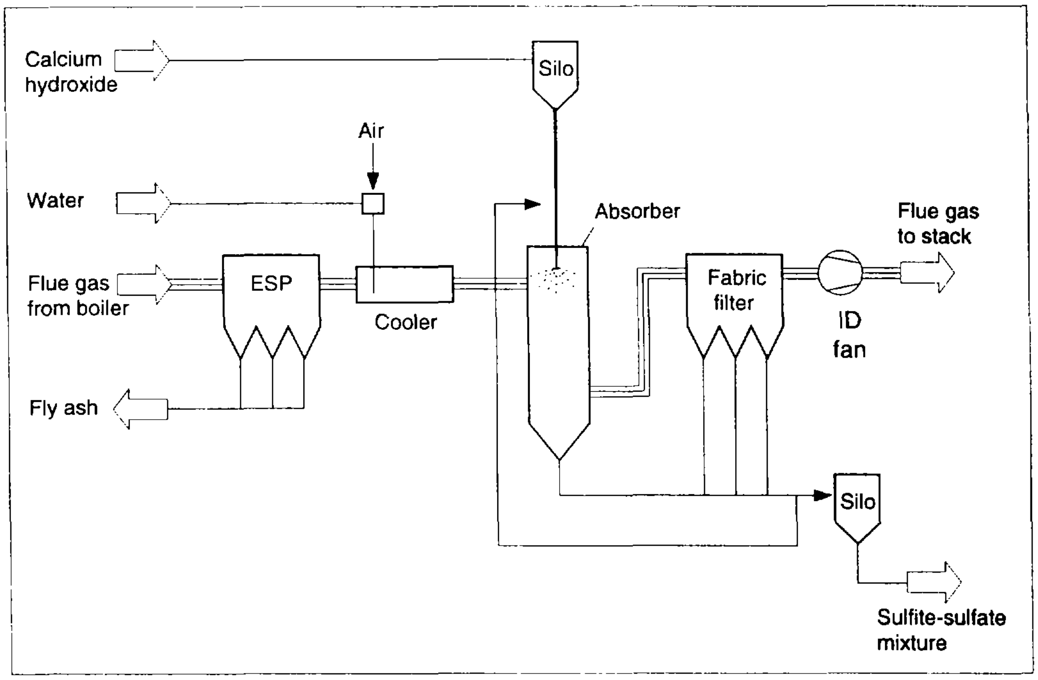


Figure 3.1 shows that calcium hydroxide (top left) is injected from a silo into the absorber, where it mixes with the flue gas to form $CaSO_4$. As the gas enters the absorber it is cooled to the "approach temperature" by water spraying. The unreacted sorbent and fly ash in the flue gas are captured downstream of the absorber in a fabric filter and are recycled into the top of the absorber or disposed (sulfite-sulfate mixture). The clean flue gas goes to the stack.

Performance. Pre-ESP sorbent injection can achieve 30 to 70 percent SO_2 removal; post-ESP injection can achieve 80 to 90 percent removal. The efficiency with which SO_x is removed depends greatly on the amount of sorbent injected (Ca/S molar ratio), the recycling of unreacted sorbent, and the approach temperature. The efficiency of SO_x removal for duct injection processes with and without sorbent recycling is shown is Figures 3.2 and 3.3, respectively.

Availability. The following points describe the commercial conditions under which pre-ESP and post-ESP duct injection technologies are available today.

- *Technology readiness.* Both technologies are in the demonstration and early commercialization phase; some pre-ESP sorbent injection plants are in operation in the United States; several post-ESP plants are operating in Europe. Pre-ESP sorbent injection plants in the United States include B&W's process, demonstrated at Ohio Edison's Edgewater 104 MW station; and Bechtel's CZD process, being demonstrated at Pennsylvania Electric's Seward 147 MW station. Post-ESP systems are being operated commercially at low-sulfur firing boilers in Europe by Lurgi Corporation of Germany and Tampella of Finland.

Figure 3.2 SO_2 Removal vs. Ca/S for Pre-ESP Duct Injection without Recycling

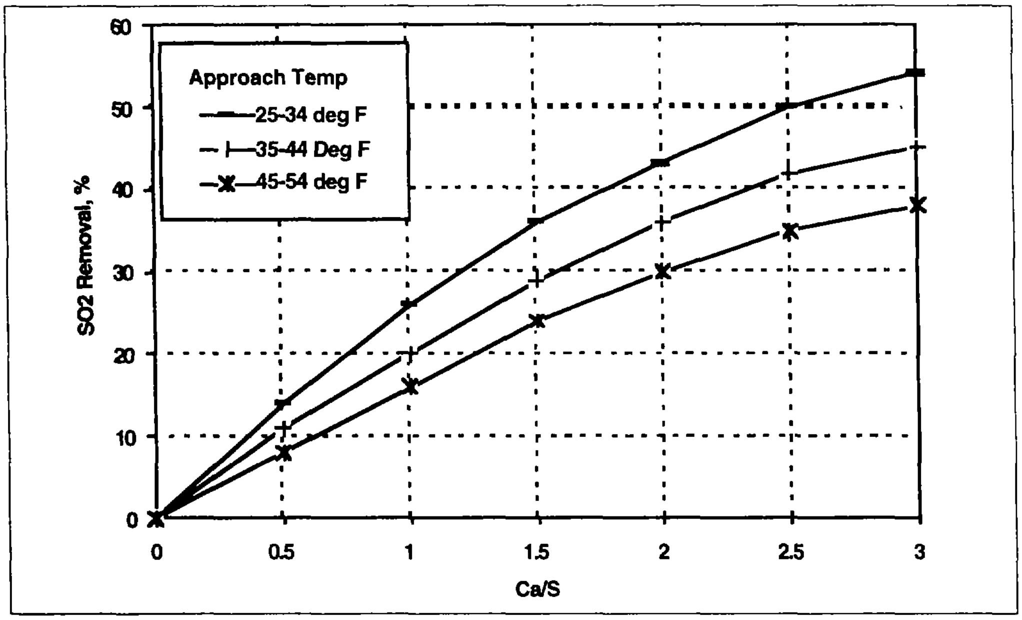


Figure 3.2 illustrates the impact of Ca/S molar ratio and approach temperature on SO_2 removal efficiency in a pre-ESP duct injection system *without recycling.*

Figure 3.3 SO_2 Removal vs. Ca/S for Pre-ESP Duct Injection with Recycling

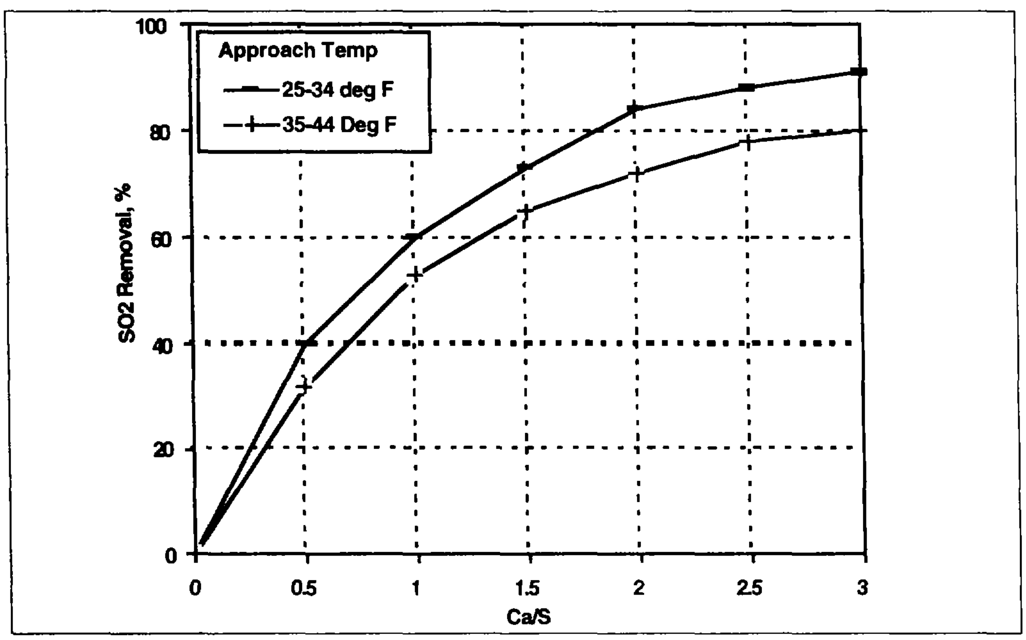


Figure 3.3 shows the relationship between Ca/S molar ratio, approach temperature and SO_2 removal efficiency in a pre-ESP duct injection system *with recycling.* Comparison of Figures 3.2 and 3.3 shows that recycling improves the SO_2 efficiency significantly.

- *Suppliers.* A list of suppliers is provided in Annex B, Table B.3.
- *Cost-effectiveness.* The cost of the pre-ESP sorbent injection process is expected to range from 60 to 120 US$/kW (Claussen 1993); post-ESP costs are similar to those of FGD processes (100 to 200 US$/kW).

Construction. If space is available for the installation of sorbent injection equipment, the downtime required for retrofitting an existing unit is 3 to 6 weeks.

Suitability. Sorbent injection is particularly suitable for short- and intermediate-term (5 to 10 years) applications in developing countries because of the following circumstances:

- Environmental regulations in most developing countries do not require very high SO_2 removal; 30 to 70 percent removal may be adequate.
- It is a simple process with low capital and O&M costs.
- The system is easy to operate and maintain.
- It is particularly suitable for retrofit applications.

Deployment. Deployment in developing countries will require further demonstration of the performance and economic attractiveness of the technology. Additional demonstrations or commercial projects in developed countries and one or two demonstration projects in developing countries may be required. Considering that such projects require 3 to 5 years to be completed, wide application of this technology in developing countries should not be expected before the end of the century. (For more information on the design of duct injection systems, see Claussen 1993.)

Wet Scrubbers/Flue-Gas Desulfurization

In most developed countries, wet scrubber (flue-gas desulfurization; FGD) technology is a well-established process for removing SO_2.

Technology. A simplified process flow diagram of a conventional wet scrubber is shown in Figure 3.4. In wet scrubbers, the flue gas enters a large vessel (spray tower or absorber), where it is sprayed with water slurry (approximately 10 percent lime or limestone). The calcium in the slurry reacts with the SO_2 to form calcium sulfite or calcium sulfate. A portion of the slurry from the reaction tank is pumped into the thickener, where the solids settle before going to a filter for final dewatering to about 50 percent solids. The calcium sulfite waste product is usually mixed with fly ash (approximately 1:1) and fixative lime (approximately 5 percent) and disposed of in landfills.

Note that "mist eliminators" installed at the spray tower outlet or downstream ductwork collect slurry droplets and remove moisture from the flue gas. In some installations, the flue gas is reheated to avoid corrosion downstream in the power plant. Many scrubbers have gas-bypassing capability, which can be used for gas reheating.

Figure 3.4 Conventional Limestone/Lime Flue-Gas Desulfurization

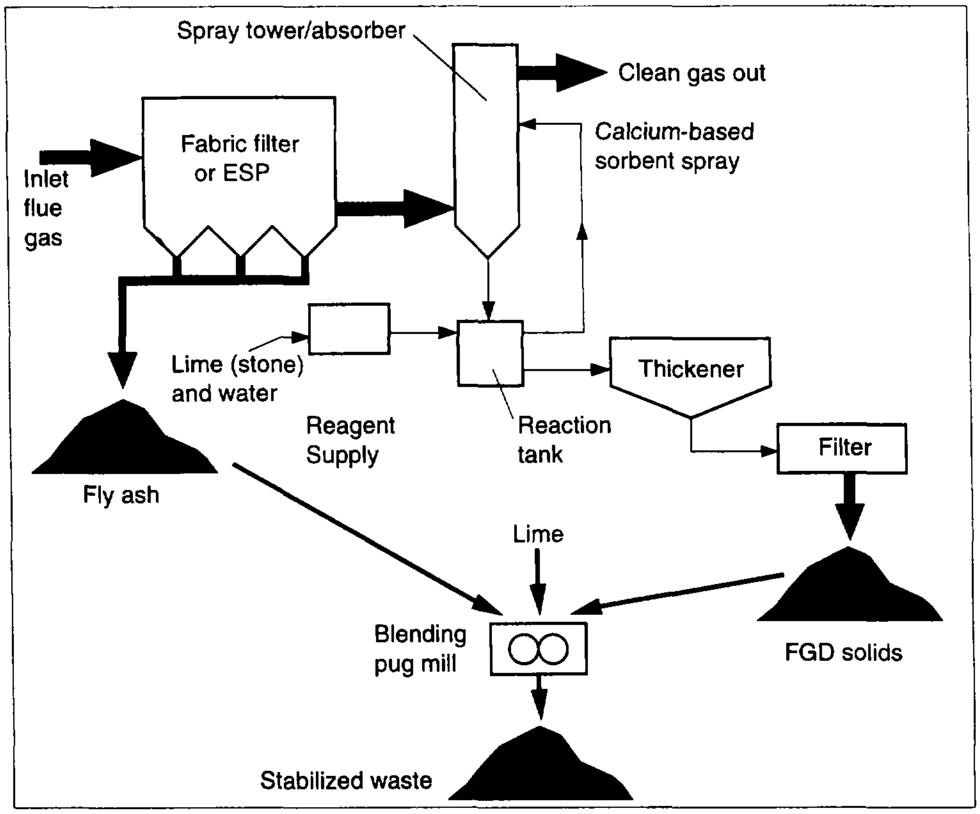


Figure 3.4 shows conventional limestone/lime flue-gas desulfurization. After leaving the particulate removal device—a fabric filter or ESP (top left)—the gas enters a spray tower or absorber (top center), where it is sprayed with a calcium-based water slurry. The calcium in the slurry and the SO_2 in the flue gas form calcium sulfite or calcium sulfate, which are removed by dewatering and settling into a thickener (center). The FGD wastes are usually mixed with the fly ash collected in the fabric filter or ESP and lime in a pug mill (bottom center), and they are disposed of in landfills.

Note: ESP = electrostatic precipitator; FGD = flue-gas desulfurization.

Often, a spare absorber is included to allow full-load operation with one absorber out of service, although the industry trend is to improve scrubber reliability and eliminate the spare module. The cost estimates presented in this report assume that one spare module is included. Presently, the largest capacity scrubber module can handle flue gas approximately equivalent to that of a 150 MW coal power plant.

Limestone with forced oxidation (LSFO) is a variation of the traditional wet scrubber (see Figure 3.5). In the LSFO process, the calcium sulfite initially formed in the spray tower absorber is nearly 100 percent oxidized to form gypsum (calcium sulfate) by bubbling compressed air through the sulfite slurry in the tower recirculation tank or in a separate vessel. Because of their larger size and structure, gypsum crystals settle and dewater better than calcium sulfite crystals, reducing the required size of by-product handling equipment. The high gypsum content also permits disposal of the dewatered waste without fixation. Gypsum also has a commercial value, and this needs to be incorporated into the overall assessment of the FGD processes.

Figure 3.5 Limestone Forced Oxidation Flue-Gas Desulfurization Process

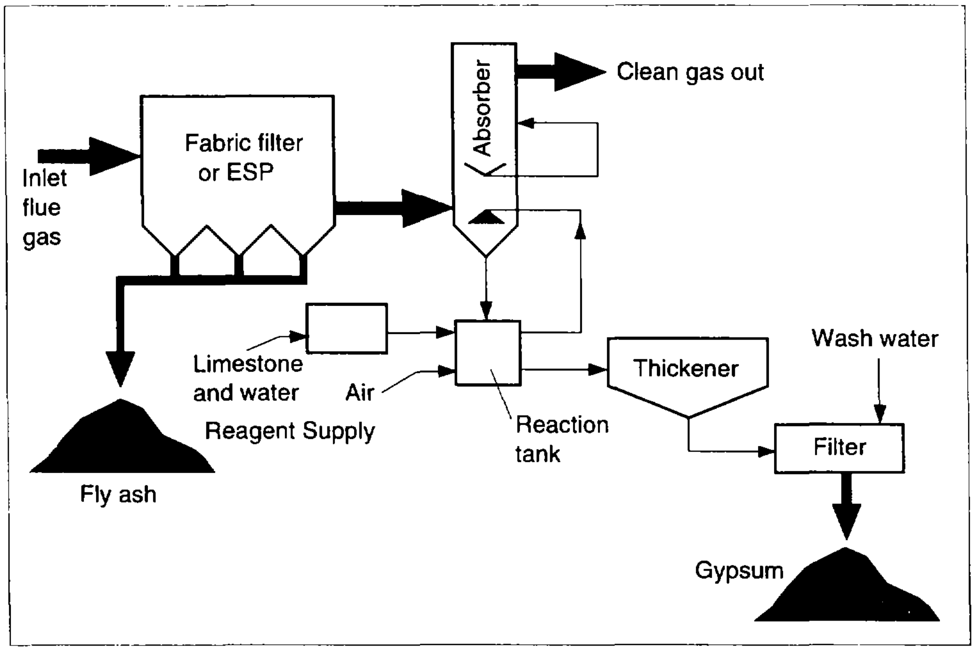


Figure 3.5 shows the limestone with forced oxidation (LSFO) process. It differs from the wet FGD process described in Figure 3.4 in that calcium sulfite formed in the absorber is oxidized to form gypsum by introducing compressed air into the slurry tank. The final FGD waste is wallboard-grade gypsum.

Note: FGD = flue-gas desulfurization.

By controlling the gypsum quality in the dewatering step, a wallboard-grade gypsum can be produced. The majority of scrubber installations in Europe and Japan generate gypsum for reuse. In the United States, sale of gypsum depends on local markets for wallboard, cement, and agricultural soil amendments.

The LSFO process with throwaway by-product is the standard process against which other FGD processes are compared.

Although FGD designs vary widely, one worth mentioning in particular is the Chiyoda Thoroughbred 121 (CT-121) process (Figure 3.6), which reflects a simplified and more integrated design than the other processes. The key improvement is a simplified absorber, which eliminates the need for spray pumps, nozzle heaters, separate oxidation towers, and thickeners. Gypsum again is the main by-product of the process. The CT-121 process is operating commercially in Japan in low-sulfur, coal-fired power plants, and it is under demonstration in the United States (Southern Company Services/Georgia Power's Yates #1 unit, 100 MW).

Figure 3.6 Chiyoda CT-121 Flue-Gas Desulfurization Process

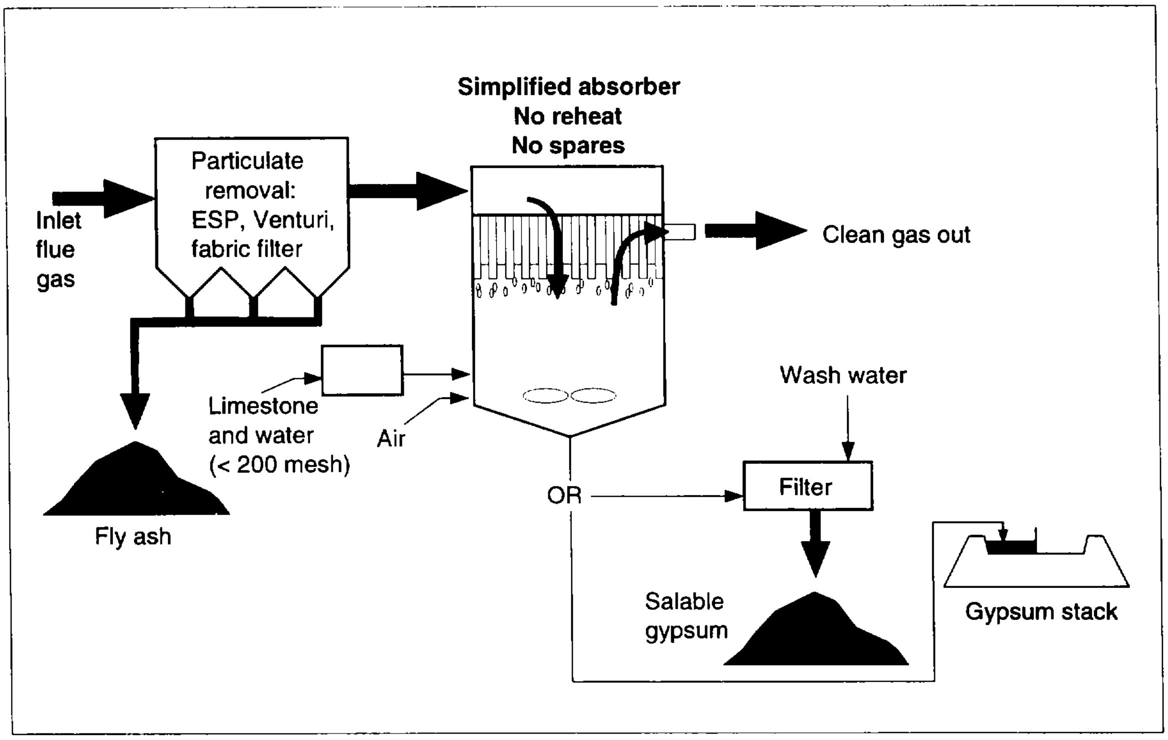


Figure 3.6 shows the absorber of the CT-121 process (top center). It is designed to eliminate the need for separate oxidation tower, thickener, and spray pumps.

Performance. Wet scrubbers are usually designed for efficiency of 80 to 90 percent SO_2 removal. Additives (e.g., magnesium-enhanced lime or adipic acid) improve the process efficiency by 5 to 10 percent, raising it to a total 95 to 99 percent. These performance levels have been proven for both high- and low-sulfur coals in many commercial applications in Europe, Japan, and the United States.

Approximately 1 to 3 percent of the unit's generating capacity is consumed to meet the power requirements of the scrubber. An additional 1 percent is consumed for gas reheating (when available).

Availability. The following points describe the commercial conditions under which wet scrubber technology is available today.

- *Technology readiness.* Wet scrubber technology is the most proven and commercially established SO_2 removal process in most developed countries (Europe, Japan, and the United States). At the end of 1993, there were more than 132 GWs of installed capacity operating worldwide. Approximately 40 GW (installed in the late 1980s) are in Germany and more than 62 GW in the United States. Of the 9,200 MW of coal-fired capacity in Japan, approximately 93 percent use scrubbers (mostly wet type).

- *Suppliers.* A list of the main FGD suppliers in Europe, Japan, and the United States is provided in Annex B, Table B.4.
- *Cost-effectiveness.* Wet scrubbers are the technology of choice for retrofit applications requiring more than 80 to 90 percent SO_2 removal. FGD cost projections are shown in Table 3.1.
- *Time for construction.* Retrofitting an existing power plant with wet scrubbers requires 3 to 6 weeks of outage to connect the FGD with the boiler piping and to construct the scrubber itself (provided that space is available).

Table 3.1 Cost Projections for Retrofit and New Construction of Flue-Gas Desulfurization Units

Cost factor	*Retrofit*	*New plant*
Capital costs (US$/kW)	150 – 270	120 – 210
Variable O&M (USmills/kWh)	1.5 – 3.3	1.3 – 3.2
Total O&M (USmills/kWh)	6.6 – 12.0	7.4 – 13.0

Note: Costs are expressed in 1990 US$.

Suitability. In general, wet scrubber technology is suitable for power plants in developing countries, but additional demonstration and adaptation of specific FGD processes may be required depending on the coal quality in each case. Suitability should also be assessed based on the SO_2 removal requirements of each country; countries with removal requirements above 80 to 90 percent should consider wet scrubber technologies; countries with lower requirements may find dry scrubbers, sorbent injection, fluidized-bed combustion, or coal cleaning more cost-effective.

Deployment. Demonstration and adaptation of the technology may be needed for some coals found in developing countries (e.g., Indian and Chinese coals). In general, deployment issues that need to be addressed by most developing countries are as follows:

- The high cost of FGD equipment puts an additional strain on the already limited financial resources of developing countries.
- A significant percentage of the capital requirements (at least during the first 3 to 7 years of technology deployment) will be in hard currency.
- Power generation companies need to obtain additional expertise in specifying, operating, and maintaining complex FGD systems, which are more like chemical plants than power plants. Companies may need more chemical engineers, chemical laboratories, and revised operating and maintenance procedures.

Dry Scrubbers (Spray Dryers)

Dry scrubbers are used commercially in Europe, Japan, and the United States.

Technology. In dry scrubbers, a calcium hydroxide slurry (quicklime mixed with water) is introduced into a spray dryer tower (see Figure 3.7). The slurry is atomized and injected (close to saturation) into the flue gases, where droplets react with SO_2 as they evaporate in the vessel. The resulting dry by-product is collected in the bottom of the spray dryer and in the particulate removal equipment (ESP or bagfilter).

Figure 3.7 Spray Dryer Flue-Gas Desulfuration Process

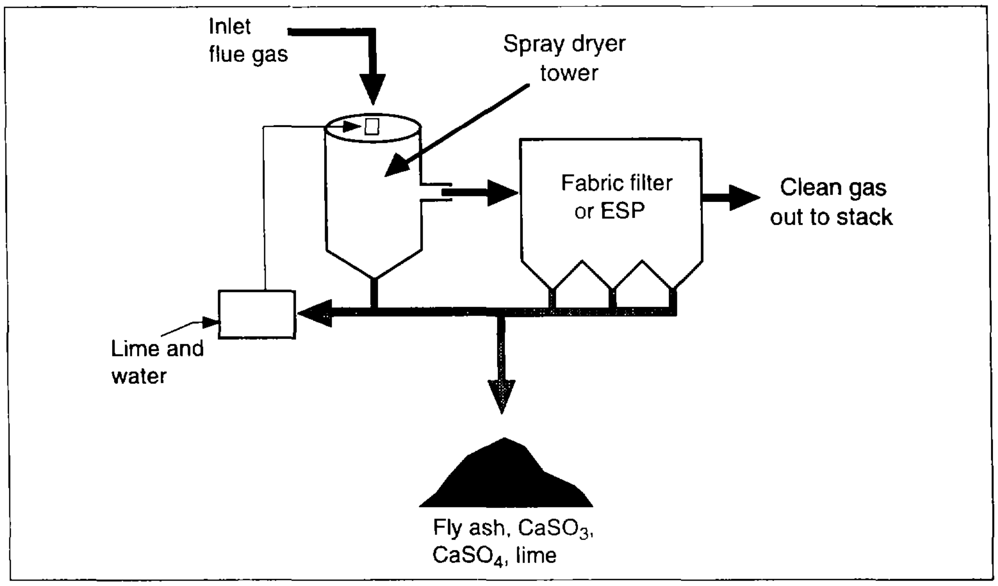


Figure 3.7 shows how lime and water (calcium hydroxide slurry) are introduced into the spray dryer tower (top center), where they mix with the flue gas to form $CaSO_4$. Fly ash, $CaSO_3$, $CaSO_4$, and unreacted lime are removed by a fabric filter or ESP downstream of the spray dryer. Part of these solid wastes is recycled into the tower; the remainder is sent to a disposal site.

A portion of the dry by-product is recycled to the spray dryer to enhance removal of SO_2 and use of alkali. Chloride injection or high chloride coals improve the performance of the spray dryer.

Performance. An efficiency of 70 to 90 percent removal of SO_2 has been achieved with low-sulfur coals. Preliminary laboratory and large-scale testing indicate that similar efficiency of SO_2 removal can be achieved with high-sulfur coals (up to 4.5 percent by weight).

Availability. The following points describe the commercial conditions under which dry scrubber technology is available today.

- *Technology readiness.* The technology has been demonstrated and used commercially with low-sulfur coals in Europe and Japan. Also, approximately 6 percent of the FGD systems in the United States (3,600 MW) use spray dryers. The performance of spray dryers with high-sulfur coals needs to be demonstrated, however. Specific issues that require further demonstration are the impact of chloride contained in the coal on spray dryer performance; and the ability of existing ESPs, if downstream from the spray dryer, to handle the increased particulate loading and achieve the required efficiency. A minimum of 300 to 400 specific collection area (SCA) is needed, depending on the sulfur and chloride content of the coal, as well as on particulate emission requirements.

- *Suppliers.* A list of suppliers is provided in Annex B, Table B.4.
- *Cost-effectiveness.* The capital cost requirements for spray dryers are lower than those for wet scrubbers (see Table 3.2), and spray dryer systems are simpler and easier to operate and maintain.

Table 3.2 Capital Cost Requirements for Spray Dryers

Cost factor	*Retrofit*	*New plant*
Capital costs (US$/kW)	140 – 210	110 – 165
Variable O&M (USmills/kWh)	2.1 – 3.2	2.1 – 3.2
Total O&M (USmills/kWh)	6.0 – 9.0	7.4 – 11.0

Note: Costs expressed in 1990 US$.

Construction. Unit outage of 3 to 6 weeks is needed to connect a spray dryer in an existing power plant.

Suitability. Spray dryers are suitable for developing countries, but demonstration may be needed (e.g., for high-ash Indian coals and high-sulfur coals generally).

Deployment. Deployment considerations are similar to those for wet FGD.

NO_x Control Technologies

Selective Noncatalytic Reduction for NO_x Control

Demonstrations of selective noncatalytic reduction (SNCR) technology have been conducted in the United States and Germany.

Technology. NO_x emissions in the flue gas are converted into elemental nitrogen and water by injecting a nitrogen-based chemical reagent, most commonly urea (CH_2CONH_2) or ammonia (NH_3; either anhydrous or aqueous). The chemical reactions, in a simplified form, are as follows:

$$2\,NO + CH_2CONH_2 + 1/2\,O_2 \longrightarrow 2\,N_2 + CO_2 + 2\,H_2O$$

$$NO_x + NH_3 + O_2 + H_2O + (H_2) \longrightarrow N_2 + H_2O$$

Because the highest NO_x reduction is achieved at temperatures between 870 and 1,200° C (1,600 to 2,200° F), the reagent is introduced at the top and backpass of the boiler. Multiple injection locations may be required, especially in case of cycling units; different injection locations are used as the unit operates at a reduced load.

Performance. SNCR technologies can reduce NO_x emissions by 35 to 60 percent without significant impacts on unit performance.

Availability. The following points describe the commercial conditions under which selective noncatalytic reduction technology is available today.

- *Technology readiness.* The technology was initially demonstrated in boilers fired by oil or natural gas, but the use of SNCR in coal-fired boilers is presently under way. The technology has been demonstrated in 15 utility-scale boilers in the United States and Europe (especially in Germany and Austria).

  Technical issues that remain to be addressed are as follows:

  - Ability to satisfactorily minimize deposition of ammonium bisulfate on the air heater baskets, which plugs them.
  - Ammonia contamination of the ash; ammonia is odorous at concentrations as low as 20 ppm.
  - Release of unreacted ammonia into the environment through the flue gas ("ammonia slip").
  - Generation of N_2O, an ozone-depleting greenhouse gas.

- *Suppliers.* Suppliers of SNCR technologies are limited; two are Nalco/Fuel Tech and Exxon Research and Engineering. Nalco's technology (NO_xOUT) is marketed in the United States and other countries by licensees such as Flakt Canada Ltd.; Rertokraft AB; Research Cottrell, Inc.; RJM Corporation; Todd Combustion, Inc.; and Wheelabrator Air Pollution Control. Exxon markets its process (Thermal DeNO_x) through similar arrangements with various organizations.

- *Cost-effectiveness.* The cost of retrofitting a boiler with SNCR is US$10 to 20/kW, whereas incorporating SNCR in a new boiler is projected to cost US$5 to 10/kW. This difference is caused by the cost associated with modifying the existing boiler to install the reagent injection ports. The operating costs associated with the reagent, auxiliary power, and potential adverse O&M impacts are usually on the order of 1 to 2 m/kWh.

Construction. Two to five weeks of outage are required to retrofit a boiler with SNCR.

Suitability and Deployment. This technology is suitable for developing countries that require NO_x reduction above and beyond what is achieved by low-NO_x burners. Developing countries should monitor the progress in industrialized countries and decide whether they want to acquire the technology, depending on their NO_x control regulations and the sucessful resolution of the outstanding issues mentioned above.

Selective Catalytic Reduction for NO_x Control

Although selective catalytic reduction (SCR) technology is widely available for low-sulfur coal, its acceptance in developing countries is hindered by the high capital and O&M costs, the need for adaptation to different types of coal, and their generally less stringent regulations regarding NO_x reduction.

Technology. SCR is similar to SNCR in that it uses ammonia injection in the flue gas to convert NO_x emissions to elemental nitrogen and water. The key difference between SCR and SNCR is the presence in SCR systems of a catalyst, which accelerates the chemical reactions. The catalyst is needed because SCR systems operate at much lower temperatures than do the SNCR; typical temperatures for SCR are 340 to 380° C (650 to 720° F), compared with 870 to 1,200° C (1,600 to 2,200° F) for SNCR. The most commonly used catalysts are a vanadium/titanium formulation (V_2O_5 stabilized in a TiO_2 base) and zeolite materials. Figure 3.8 illustrates hot- and cold-side SCR systems.

Performance. SCR has a demonstrated ability to remove 70 to 90 percent of the NO_x emissions from low-sulfur-firing boilers. Similar NO_x reduction is expected with medium- to high-sulfur coals, but such performance has not been demonstrated in utility-scale boilers.

Availability. The following points describe the commercial conditions under which selective catalytic reduction technology is available today.

- *Technology readiness.* SCR is commercially available throughout the world for low-sulfur coal (less than 1.5 percent on a dry-weight basis). SCR has been installed and is operating in more than 30 GW of coal-fired capacity in Germany and 6 GW in Japan. In addition, Japan has more than 15 GW of oil-fired capacity utilizing SCR. In the United States, the focus is on demonstrating the performance and economics of SCR in medium- and high-sulfur coals.

  Issues that need to be addressed are as follows:

  - Quantity of catalyst required to achieve a specific NO_x reduction
  - Catalyst life (alkali and arsenic in the coal reduce the useful life of the catalyst)
  - Required ammonia (NH_3:NO_x molar ratio) to achieve a specific NO_x reduction
  - Percentage of unreacted ammonia released into the environment ("ammonia slip")
  - Conversion of SO_2 to SO_3; most catalysts convert 0.5 to 1.5 percent of the incoming SO_2 to SO_3, which affects NO_x removal efficiency
  - Impact of SCR on unit reliability, especially the problem of air heater plugging
  - Overall cost-effectiveness, relative to other NO_x control options.

Figure 3.8 Hot- and Cold-side (Post-FGD) SCR Systems

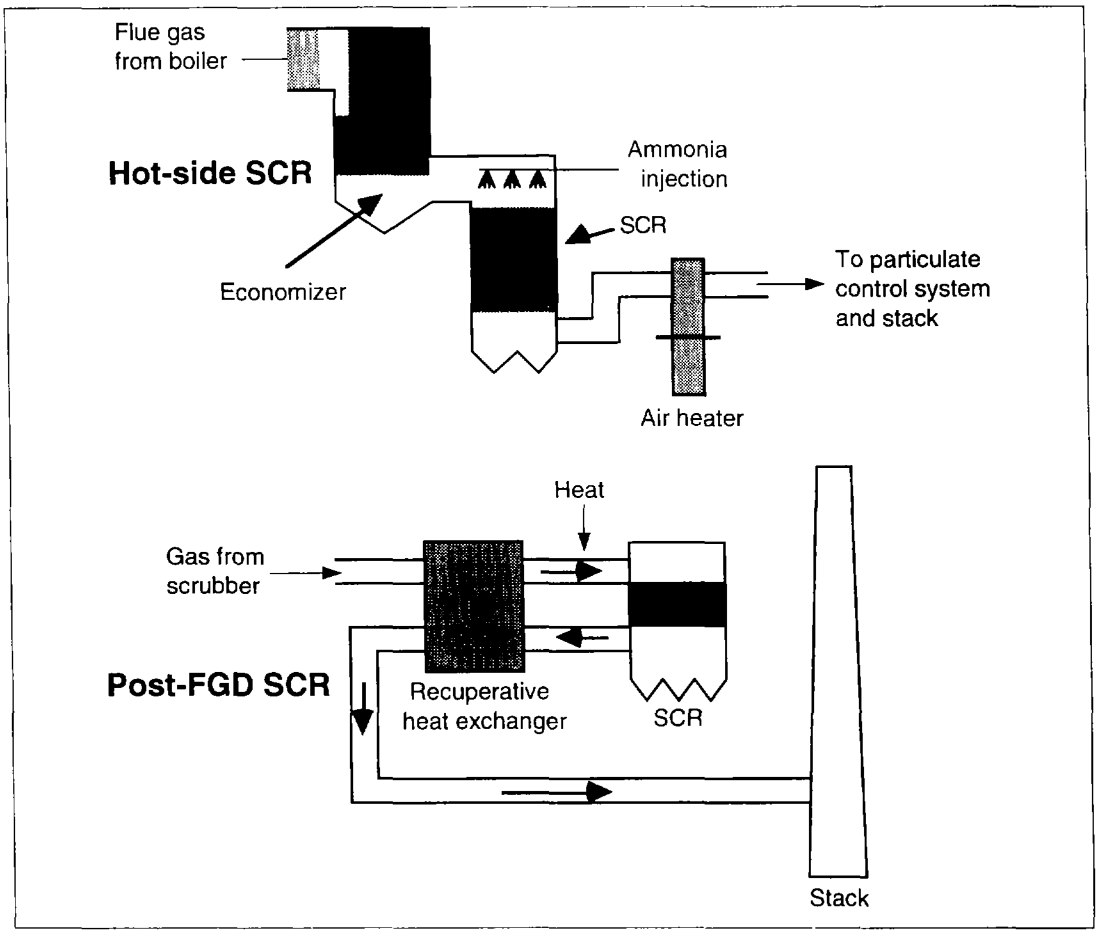


Figure 3.8 shows the SCR, located either between the economizer and the air heater ("Hot-side" SCR, top half of figure) or downstream from the particulate removal and FGD ("Cold-side" or "Post-FGD" SCR, bottom half). Hot-side SCRs operate at flue-gas temperatures of 340 to 380° C (650 to 720° F). Post-FGD SCRs operate at approximately 330° C (625° F), and thus the flue gas must be reheated before it enters the SNCR.

Note: FGD = flue-gas desulfurization; SCR = selective catalytic reduction.

Hot-side SCR systems are installed between the economizer and the air heater; therefore, they require extensive modifications of the boiler backpass. Lack of available space is very often a constraint, and may result in design compromises and/or increased costs. Post-FGD SCRs are installed downstream of the particulate control and FGD, where there is more space. To illustrate the space requirements of SCRs: a 500 MW unit needs a total of 38 m x 30 m plan area x 30 m high (125 ft. x 100 ft. x 100 ft.), including structural steel, stairs, walkways, and so on.

- *Suppliers.* A list of suppliers is provided in Annex B, Table B.5.

- *Cost-effectiveness.* Capital costs range from US$50 to 150/kW, depending on the required NO_x emission reduction, unit layout (available space and interferences), catalyst unit price, cost of ammonia, and type of SCR (hot-side vs. post-FGD). Hot-side SCRs typically cost US$50 to 100/kW, whereas post-FGD SCRs cost US$120 to 150/kW.

O&M costs for SCR are expected to add 4 to 8 m/kWh, depending on the catalyst life (typically 3 to 5 years) and the catalyst cost (typically 300 to 600 US$/cu. ft.).

Construction. Hot-side SCR retrofits require 2 to 3 months outage, whereas post-FGD SCR retrofits require 3 to 6 weeks outage.

Suitability. Technically, SCR is suitable for coal-fired power plants in developing countries. However, technology demonstration and potential adaptation to unique coal characteristics may be required. Furthermore, environmental regulations in developing countries often do not require the 80 to 90 percent level of NO_x reduction achieved by SCR.

Deployment. The main factors that prevent the use of SCR technology in developing countries are the lack of regulations requiring high NO_x reduction (80 to 90 percent) and the high cost of SCR relative to other options (low-NO_x burners and SNCR).

Combined SO_x/NO_x Control

General Description

More than a hundred processes are under development that combine SO_2 and NO_x removal to reduce the design and operating complexity of these systems. The intent is to provide a cost-effective alternative to the combination SCR–wet FGD.

Technology. Combined SO_2/NO_x control processes include adsorption/ regeneration, flue-gas irradiation, wet scrubbing with additive for NO_x removal, gas/solid catalytic operations, electrochemical processes, and dry alkali processes. Each category comprises many processes, and since the technologies are only in the development stage, the report will not describe them. More information is available from Cichanowicz (1990); EPRI (1993); Frank and Hirano (1988); Haslbeck and others (1993); and *Power Magazine* (1990). The last in particular summarizes the technologies, developers, commercial status, and unique features.

Examples. Two examples of SO_2/NO_x control processes in the early demonstration stage are shown in Figures 3.9 and 3.10, respectively.

Performance. An NO_x removal of 80 to 90 percent and a similar level of SO_2 removal are expected from these processes. The main advantages and disadvantages of six selected categories of combined SO_2/NO_x control processes are provided in Table 3.3 (Cichanowicz 1990).

Figure 3.9 The SO_x/NO_x Process

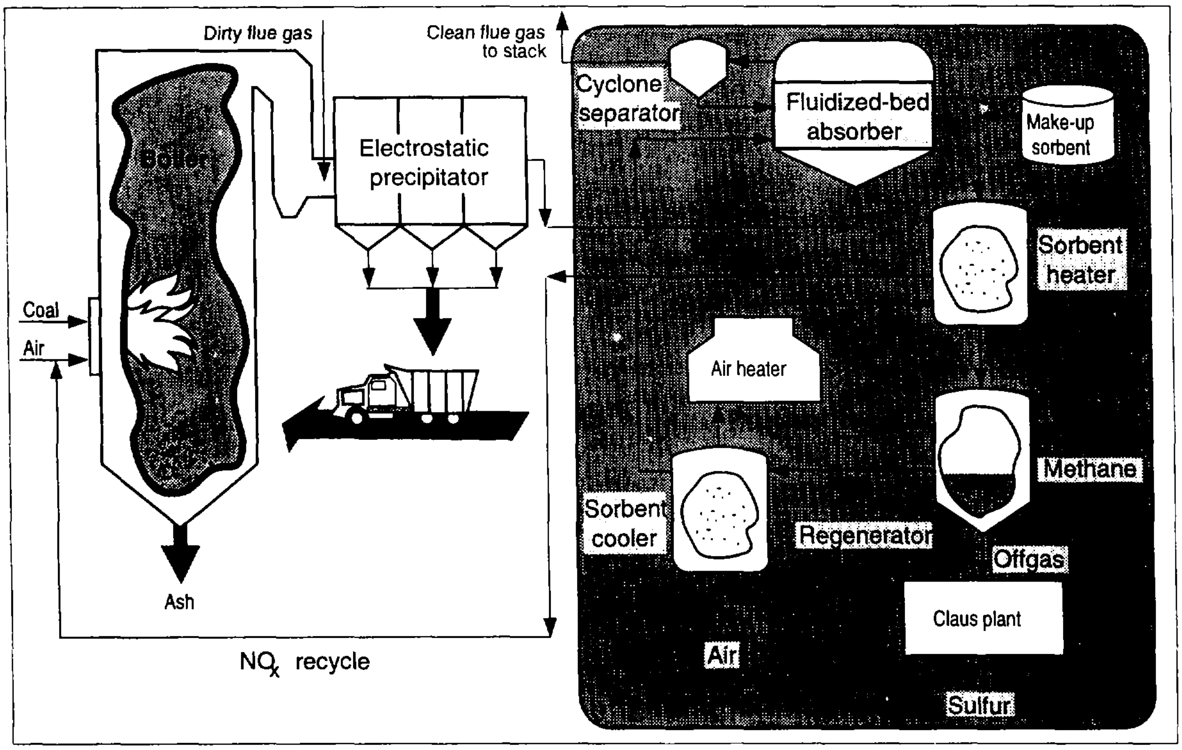


Figure 3.9 shows the SO_x/NO_x process. Sorbent is injected into an absorber, where it reacts with the SO_2 in the flue gas to form $CaSO_4$ and reduces the NO_x to elemental nitrogen. Sorbent regeneration and production of sulfur (through a Claus plant, bottom right) complete the process.

Figure 3.10 The SO_x-NO_x-ROX Box Process

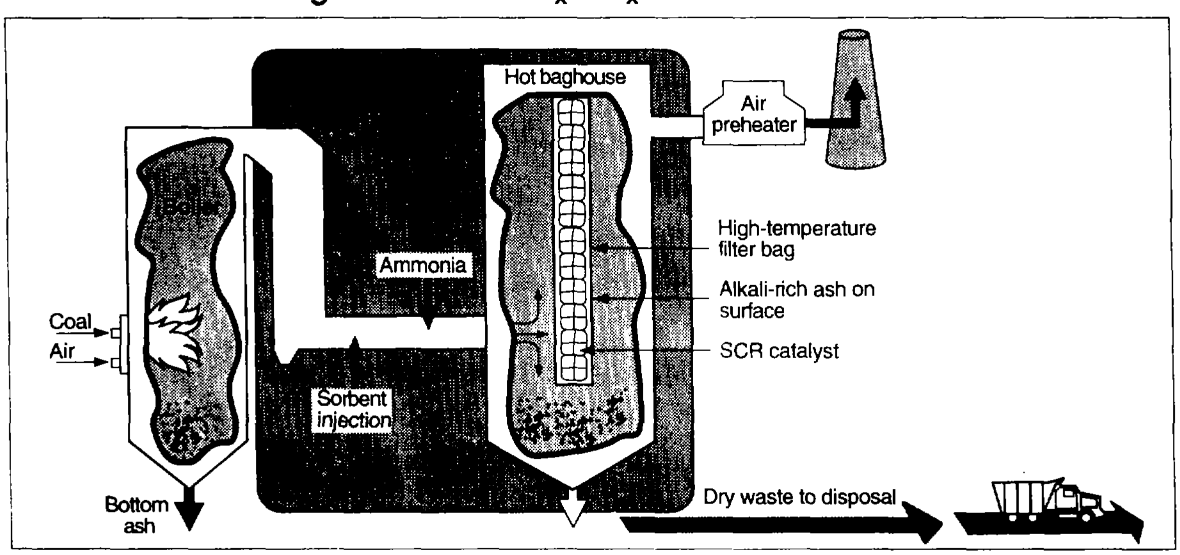


Figure 3.10 illustrates the SO_x-NO_x-ROX Box process. It is based on a high-temperature fabric filter (in the "hot baghouse," center), which includes an SCR catalyst. Sorbent injection before the baghouse removes the SO_2, and ammonia injection reduces NO_x into nitrogen.

Table 3.3 Comparison of Combined SO_2/NO_x Control Processes

Process	*Advantages*	*Disadvantages*
Adsorption/ regeneration	High-temperature gas is not required High removal efficiency Low volume of wastes Potentially marketable by-product	Solids recirculation is complex High sorbent costs High flue-gas pressure loss
Flue gas irradiation	High temperature gas is not required SO_2, NO_x, and particulate removal in one device Potentially marketable by-product	High auxiliary power High-cost reagent (ammonia) Potential for secondary emissions (e.g., N_2O) By-product difficult to dispose of
Wet scrubbing additive for NO_x removal	Easily retrofittable to scrubbers One vessel for SO_2 and NO_x removal Process chemistry also suitable for high-sulfur coals	Complex and precise process control needed Wastes contain nitrogen/sulfur compounds Flue-gas reheating may be required
Gas/solid catalytic operations	No solids recirculation High SO_2 and NO_x removal Potentially marketable by-product	High-temperature gas needed Acid collection adds complexity Catalysts must be replaced periodically
Electrochemical	Mechanically simple One device for both SO_2 and NO_x removal No reagents needed No high volume wastes	High auxiliary power required High-temperature gas required
Dry alkali	High-temperature gas not required Easily retrofittable to dry scrubbers	High simultaneous SO_2 and NO_x removal may not be possible Wastes difficult to dispose of Potential for secondary emissions (e.g., NO_2)

Source: Power Magazine (1990).

Availability. The following points describe the commercial conditions under which combined SO_x/NO_x control technology is available today.

- *Technology readiness.* Most of these processes are in the early development stage and are not expected to be commercially available before year 2000.
- *Suppliers.* See *Power Magazine* (1990).
- *Cost-effectiveness.* Early projected capital costs range from US$300 to 400/ kW; the O&M costs range from 10 to18 U.S. mills/kWh. The cost relative to that of other options cannot be assessed at this time because of the early developmental stage of these technologies.

Suitability. The suitability and deployment of the combined SO_2/NO_x control processes in developing countries should be assessed after they have been demonstrated and commercialized in industrialized countries (3 to 10 years, depending on the process).

Particulate Removal Technologies

Electrostatic Precipitator Technology Enhancements

ESP is a well-known technology for controlling emissions of particulates. The purpose of this section is not to describe the conventional ESP technology, but to present a number of recent design and operating enhancements made to improve the efficiency and cost-effectiveness of ESP, as well as to give the basic information on availability, construction time, and so on.

ESP performance improvements were made for a variety of reasons, including the following:

- Tightening of regulations for particulate removal
- Adverse impact of switching from one coal to another, or deteriorating coal quality, on ESP performance
- Adverse impacts of upstream processes (e.g., sorbent injection), which affect the morphology and resistivity of the ash.

ESP Design and Operating Enhancements. Enhancements of ESP technology include the following:

- Wide plate spacing, which reduces the specific collection area (SCA) and overall ESP costs while maintaining the collection efficiency by operating at higher voltages (sparking voltage level increases with wider plate spacing)
- Intermittent energization, which improves performance and reduces auxiliary power requirements (small performance improvement, low-cost option)
- Pulse power supply (moderate performance improvement, high-cost option)
- Increasing ESP size (high performance improvement, high-cost option)
- Flue-gas conditioning; both SO_3 and ammonia conditioning of the gas before entering the ESP are proven technologies that substantially improve the ESP performance
- ESP automatic voltage controls and other energy management systems (high performance improvement and low cost).

For more information see Chang and Altman (no date), EPRI (1994), and Offen and Altman (1991).

Availability. The following points describe the commercial conditions under which electrostatic precipitator enhancement technology is available today.

- *Technology readiness.* All the above ESP enhancements are commercially available.

- *Suppliers.* Most suppliers of conventional ESPs offer the above options for new ESPs, as well as for retrofit applications.
- *Cost-effectiveness.* Typical cost of a new ESP designed to remove 99.0 to 99.7 percent particulates (the U.S. standard) ranges from US$40 to 60/kW. Higher collection efficiency may increase the cost up to 100 US$/kW. The cost of the above ESP enhancements ranges from US$1 to 20/kW. The cost-effectiveness of each option is site-specific and depends on a number of factors, which include the performance and design specifications of existing ESP, ESP age and remaining life, required performance improvement (potentially required by new environmental regulations), and cost of power (U.S. mills/kWh).

  The flue-gas conditioning equipment costs do not necessarily increase with increasing unit size. That is, large units can be fairly inexpensive (US$1/kW) and small units very expensive. Total O&M costs of conventional ESPs range from US2 to 4 mills/kWh.

Construction. ESP enhancements (with the exception of an ESP size increase) do not require more than 2 to 6 weeks of unit outage. Increasing the size of the ESP requires a 2 to 3 month outage.

Suitability and Deployment. The ESP enhancements described in this section are suitable for developing countries but have not been widely used because particulate-related regulations are not as tight as they are in industrialized countries. If regulations are tightened and some clean coal technologies are used (especially spray dryers, sorbent injection, and fluidized-bed combustion) such ESP enhancements will be needed. If a market for such enhanced ESP features develops, supply should not be a problem.

Fabric Filter (Baghouse) Technologies

Bagfilters or baghouses are based on the following operating principle: particles and flue gas are separated in tube-shaped filter bags arranged in parallel flow paths. The particulates are collected either on the outside (dirty gas flow from outside-to-inside) or the inside (dirty gas flow from inside-to-outside) of the bag.

Technology. The main differences among the various types of fabric filter technologies are related to the type of bag cleaning method. There are four general types of baghouses: reverse-gas, shake-deflate, pulse-jet, and sonic cleaning. These are described in Bustard and others (1988) and Carr and Smith (1984).

Performance. Baghouses have been used in Canada, Europe, Japan, and the United States extensively during the last ten years because they are efficient at dust collection. Industrialized countries have started using bagfilters instead of ESPs because very often regulations require a collection efficiency above 99 percent, even for particles in the 0.05 to 1.0 micron range, which can be achieved more cost-effectively with bagfilters.

Reverse gas-type baghouses are the most widely used, but they are expensive to build and operate. In addition to their large size, the pressure drop (and hence, the required auxiliary power) increases with time after each filter cleaning. Improved fabric materials and the addition of sonic cleaning improve the performance and cost-effectiveness of this technology. For more detailed descriptions of the recent advances in baghouse technology see Carr (1988); Chang and Altman (no date); Makansi (1986).

Availability. The following points describe the commercial conditions under which baghouse technology is available today.

- *Technology readiness.* Presently, more than 30 GW of baghouse capacity is installed in the United States and Canada. Baghouse technologies have been demonstrated adequately, and are commercially available throughout the world. However, they are not used widely in developing countries because of the high capital costs and, occasionally, because of the need to import the filter bag material.
- *Suppliers.* A list of equipment suppliers is provided in Annex B, Table B6.
- *Cost-effectiveness.* In general, ESPs are more competitive (lower capital and levelized costs) than baghouses for collection efficiency below 99.0 to 99.5 percent. In cases in which more than 99.5 percent collection efficiency is required, especially for low-sulfur coals, baghouses are more cost-effective. Typical costs for baghouses range from US$50 to 70/kW. Levelized costs are 3.5 to 4.5 mills/kWh for baghouses.

Suitability. Baghouse technologies are suitable for developing countries. In particular, if developing countries use technologies such as spray dryers, sorbent injection, and atmospheric fluidized-bed combustion, baghouses will be required.

Deployment. The key factors for use of baghouses in developing countries are the following:

- Particulate emission requirements in developing countries favor ESPs, which are the most cost-effective systems for collection efficiencies of less than 99 percent.
- The fabric bags may not be locally available and will need to be imported, requiring hard currency.
- Power plant operating and maintenance personnel must be trained.

Hot-Gas Cleanup Technologies

Hot-gas cleanup technologies are in an early stage of development.

Technology. Hot-gas cleanup (HGCU) technologies have emerged as key components of advanced power generation technologies such as pressurized fluidized-bed combustion (PFBC), and integrated gasification combined cycle (IGCC). The main difference between HGCUs and conventional particulate removal technologies (ESP and baghouses) is that HGCUs operate at higher temperatures (500 to 1,000° C) and pressures (10 to 20 bar), which eliminates the need for cooling of the gas.

The most promising HGCU technologies are ceramic candle filters (see Figure 3.11), ceramic cross-flow filters, screenless granular-bed filters, acoustic agglomerators, and hot electrostatic precipitators.

Figure 3.11 Hot-Gas Ceramic Candle Filter

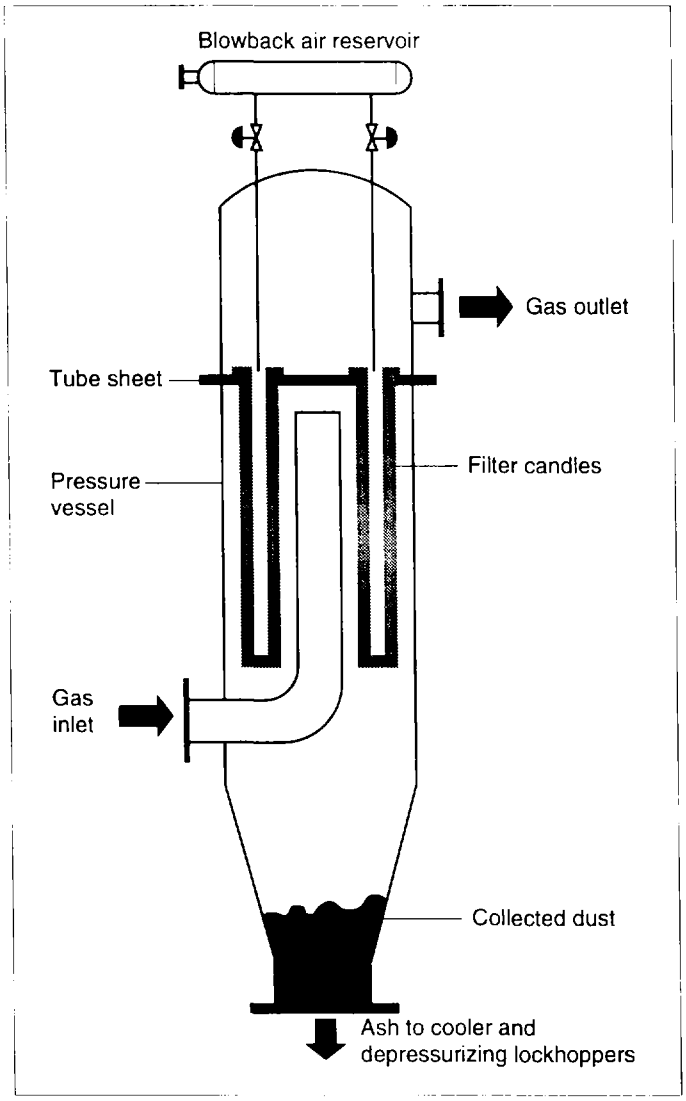


Figure 3.11 shows a schematic of a hot-gas filter. In the ceramic candle filter shown, gas flows from the outside of the candle inside (lower left). The particulates are collected on the outside surface of the candles, and the clean gas flows to the top of the pressure vessel and the stack through the gas outlet (upper right). Periodic cleaning of the candles is done by injecting air from the blowback air reservoir (top).

Performance. The particulate removal requirements of HGCU systems are driven by particulate emissions standards and operating requirements to maintain reliable gas turbine operation. Additional design requirements include maximum volatile organic and alkali content at the HGCU outlet. Typical design requirements include greater than 99.9 percent removal efficiency of particulates larger than 10 microns. In some cases, similar removal efficiencies are required for particle sizes as low as 2 microns.

Availability. The following points describe the commercial conditions under which hot-gas cleanup technology is available today.

- *Technology readiness.* HGCU is in the early demonstration stage in industrialized countries. Of the above technologies, the more advanced are the ceramic candles and ceramic cross-flow filters (at pilot-scale demonstration).
- *Suppliers.* The main developers of HGCU systems are Asahi Glass of Japan (ceramic candle filter), Combustion Power Co. of the United States (moving granular bed filter), Research Cottrell of the United States (hot ESP), Schumacher of Germany (ceramic candle filter), and Westinghouse Electric of the United States (ceramic cross-flow filter).
- *Cost-effectiveness.* Because HGCU technologies are at an early development stage, an evaluation of cost-effectiveness is premature. In addition, HGCU technologies do not compete directly with conventional particulate removal technologies (ESPs and baghouses).

Suitability. HGCU technologies are suitable for many of the coals found in developing countries. However, their applicability in developing countries is tied to the utilization of PFBC and IGCC technologies, which are still under development in industrialized countries.

4

Advanced Coal Utilization Technologies

Advanced coal utilization technologies include fluidized-bed combustion (both atmospheric and pressurized), which is generally ready for use in developing countries, as well as technologies still in high-cost or demonstration phases, such as integrated gasification combined cycle, and coproduction of electricity and clean fuels such as low- to medium-Btu gas and gasoline. In addition, this chapter discusses some advances in conventional pulverized-coal (PC) technologies that aim at enhancing cost effectiveness and efficiency.

Fluidized-Bed Combustion

Two basic types of fluidized-bed combustion are in operation—atmospheric fluidized-bed combustion (AFBC) and pressurized fluidized-bed combustion (PFBC). They are discussed below.

Atmospheric Fluidized-Bed Combustion

AFBC technologies are adaptable to both new and existing installations, work well in combination with other technologies, and are suitable for many local coals. However, their acceptance in many developing countries has been slowed by a lack of regulations requiring high removal of SO_2.

Technology. AFBC boilers differ from conventional pulverized-coal boilers in AFBC boiler/systems have the following processes and characteristics:

- Limestone is injected into the furnace to capture the sulfur and remove it as a dry by-product.
- Gas temperature in the boiler is 820 to 840° C (1,500 to 1,550° F), which affects the overall boiler design and the arrangement of heating surfaces.

Figure 4.1 highlights the main differences between AFBC and PC boilers, as well as the two AFBC types: bubbling and circulating.

A more detailed description of the AFBC process is provided in Tavoulareas (1991); Tavoulareas (1993); and EPRI and EMENA (1989).

Figure 4.1 Differences between Pulverized Coal and Atmospheric Fluidized-Bed Combustion Boilers

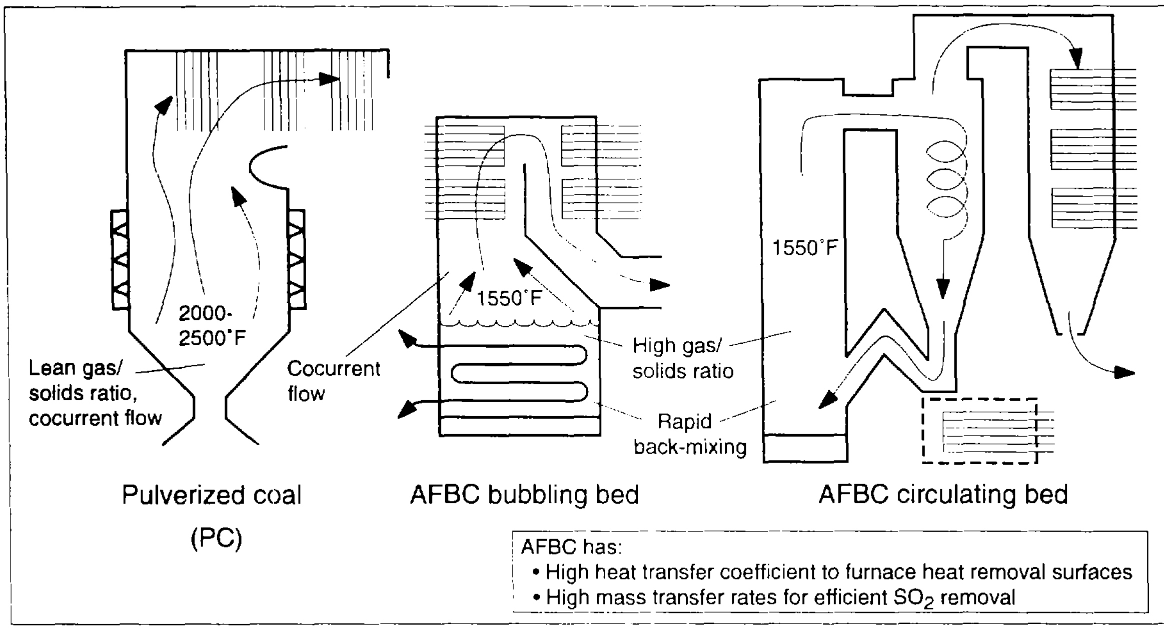


Figure 4.1 shows how AFBC boilers (center and right) differ from conventional PC boilers (left). AFBC boilers operate at lower gas temperature, have high solids/gas ratio, high furnace heat transfer rates, and high mass transfer rates for efficient SO_2 removal.
Source: EPRI and EMENA (1989), page 11.

Performance. AFBC boilers can remove up to 90 to 95 percent SO_2, while generating 100 to 300 ppm NO_x emissions. Bubbling AFBC usually removes 70 to 90 percent of the SO_2 depending on the coal's characteristics and the amount of limestone added. Circulating AFBC can achieve 95 percent SO_2 removal, with a calcium-to-sulfur (Ca/S) molar ratio of 1.5 to 2.0. NO_x emissions can be reduced further (to 10 ppm) with the addition of selective noncatalytic reduction (SNCR) processes. Boiler and overall plant efficiency of both AFBC types are similar to those of conventional pulverized-coal plants.

AFBC boilers are capable of burning low-quality coals (e.g., low-heating-value lignites, coal cleaning wastes, petroleum coke, and other waste materials). Also, the same boiler can accommodate a wider range of fuels than conventional pulverized-coal boilers.

Because of the addition of limestone to the process, AFBC plants generate more solid wastes than conventional pulverized-coal plants. However, pulverized-coal plants with sorbent injection or spray dryers are expected to generate similar amounts of solid wastes, while wet scrubbers produce sludge, which is more difficult to handle and dispose of. In the United States, AFBC solid wastes have been classified as nonhazardous and therefore can be used for a number of applications (sub-base material for road construction, lightweight aggregate, cement production, and low-strength concrete materials).

AFBC technology is suitable for new power plants, retrofit (replacement of the existing boiler with an AFBC), and boiler conversion (replacement of part of the boiler with AFBC) applications. AFBC can also be combined with other technologies to meet the specific needs of each site. Of particular interest is the combination of coal cleaning, pulverized-coal, and AFBC technologies. Physical coal cleaning may be used to provide clean coal for a pulverized-coal plant, whereas the coal cleaning wastes and raw coal can be burned in the AFBC. The ability to burn the coal wastes in the AFBC introduces significant flexibility as to how the coal cleaning plant operates. It can be operated in such a way that it produces lower sulfur coal without regard to the generation of wastes with high thermal value. This concept is described in more detail by Miliaras (1991).

Availability. The following points describe the commercial conditions under which atmospheric fluidized-bed combustion technology is available today.

- *Technology readiness.* AFBC technology has been demonstrated and is commercially available for modules up to 200 MW. More than 160 boilers (5.5 GW of installed capacity) are operating in North America, similar capacity is operating in Europe, and China has more than 2,000 small bubbling AFBC boilers in operation.

  A number of projects are planned or presently implemented in the 250 to 350 MW size range. Electric Power Development Corporation of Japan has converted a 350 MW PC boiler at Takehara to a bubbling AFBC. EdF of France is building a 250 MW circulating AFBC (Lurgi technology), and a 250 MW project is under consideration for funding by the U.S. Department of Energy. In general, projects above 200 MW have higher technological risks, which must be addressed on a project-by-project basis.

  Because of the high SO_2 removal requirements in developed countries (usually above 90 percent removal), most of the recent projects utilize the circulating AFBC option. Bubbling AFBCs are not expected to be widely used in developed countries.

- *Suppliers.* A list of suppliers is included in Annex B, Table B.7.

- *Cost-effectiveness.* AFBC technology is 5 to 15 percent less expensive than a similar size pulverized-coal plant with dry or wet scrubbers (70 to 90 percent SO_2 removal). Projected capital costs for a 150 to 200 MW AFBC range from US$1300 to 1600/kW. AFBC technology is the technology of choice when fuel flexibility is desirable, low-quality fuels are available, low-NO_x emissions are required, and high (70 to 90 percent) SO_2 removal is desired.

Construction. Lead time is one year less than that for conventional PC because of the ability to utilize small, standardized modules (e.g., 90 or 150 MW each).

Suitability. AFBC technology is particularly adaptable for developing countries because it can burn the local coals (especially in China, India, Pakistan, and Eastern Europe). In addition, AFBC is similar in design, manufacturing, and operation to pulverized-coal technology. Thus, it can be introduced and used by developing countries with minimal transition and effort.

Although circulating AFBC is the preferred option in developed countries, developing countries may also choose bubbling AFBC technology, which provides adequate SO_2 removal (70 to 90 percent), is less expensive, and is simpler to operate.

Deployment. The main barrier keeping AFBC from wide application in developing countries is the lack of high SO_2 removal requirements. In developing countries, AFBC has to compete against conventional pulverized-coal plants, which have no SO_2 control technology. As SO_2 removal requirements increase to 60 to 90 percent, more and more AFBC boilers are likely to be used in developing countries.

Pressurized Fluidized-Bed Combustion Technology

Four PFBC plants are operating in Europe, Japan, and the United States.

Technology. PFBC technology uses a combustion process similar to that of AFBC, but the boiler operates at higher than atmospheric pressure (5 to 20 bar), the gas is cleaned downstream from the PFBC boiler, and the gas is expanded in a gas turbine (see Figure 4.2). More details of the PFBC process, and the design variations, are presented in Tavoulareas (1991).

Performance. PFBC has the advantages of AFBC technology (high SO_2 removal, low-NO_x emissions, ability to burn low-quality fuels, and fuel flexibility) in addition to:

- Compact design suitable for shop fabrication and modular construction
- Easier retrofit than for AFBC into existing power plants, because of the limited space requirements
- Potential for achieving higher plant efficiency (up to 45 percent) than conventional pulverized coal or AFBC (36.5 percent)
- Lower capital costs than IGCC or pulverized-coal with wet scrubbers.

The demonstrated performance of PFBC technology is as follows:

- More than 90 percent SO_2 removal, with a calcium-to-sulfur (Ca/S) molar ratio of 1.5 to 3.0
- NO_x emissions at 100 to 200 ppm; NO_x emissions can be reduced further with the utilization of selective noncatalytic reduction technologies
- 40 to 42 percent efficiency in a combined cycle arrangement.

Availability. The following points describe the commercial conditions under which pressurized fluidized-bed combustion technology is available today.

- *Technology readiness.* PFBC technology is in the demonstration phase. Four PFBC plants are in operation (American Power Electric's Tidd in Ohio, ENDESA's Escatron in Spain, Stockholm Energi's Vartan plant, and EPDC's 70 MW Wakamatsu plant in Japan); all utilize PFBC modules of approximately 70

MWe. One demonstration plant is in the design-construction phase: Kyushu Electric's 350 MW K1 plant in Japan.

The leading PFBC suppliers are willing to provide the technology, with commercial guarantees. However, a thorough risk assessment is recommended as specific design features may not be proven and might introduce increased risks. Areas that should receive particular attention are

- Hot-gas cleanup technology; especially the demonstrated performance and reliability of the specific cleanup technology
- Coal and sorbent preparation and feed systems
- Effects of the PFBC boiler gas contaminants on gas turbine performance, reliability, and life expectancy.

• *Suppliers*. The leading developer and supplier of PFBC technology is ABB Carbon, with a number of licensors, such as Babcock & Wilcox in the United States and Ishikawajima Heavy Industries (IHI) in Japan. Other suppliers are Ahlstrom in Finland and Lurgi-Lentjes-Babcock in Germany.

Figure 4.2 PFBC Combined Cycle Technology

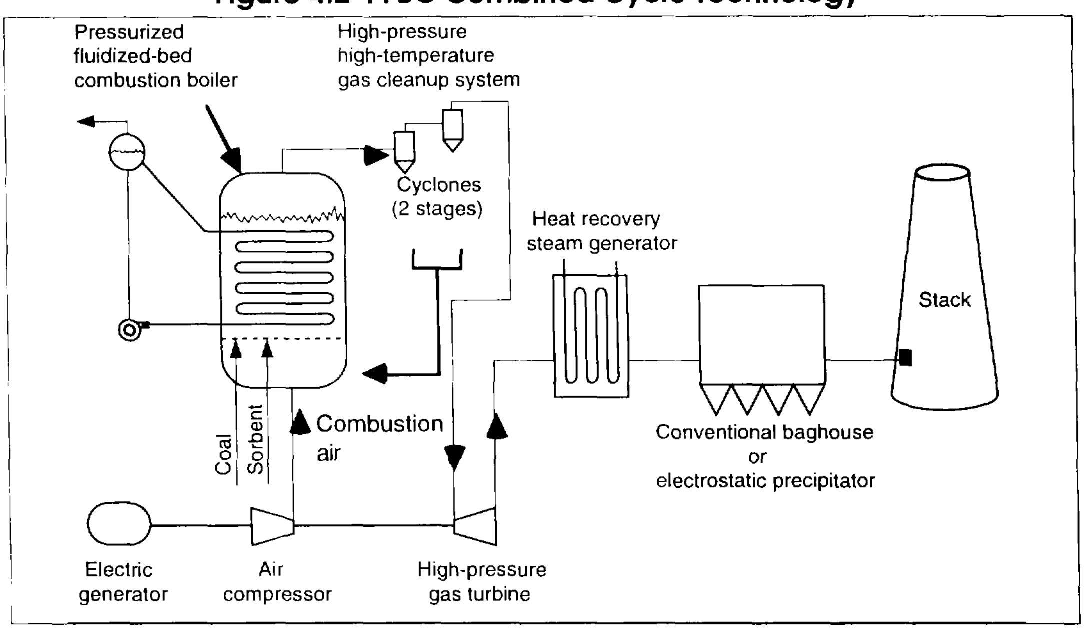


Figure 4.2 shows a typical pressurized fluidized-bed combustion (PFBC) combined-cycle system. Coal and sorbent are introduced at the bottom of the PFBC boiler (left), where the coal is burned and the sorbent reacts with the SO_2 to form $CaSO_4$. Cyclones (top center) or other hot-gas cleanup devices remove the particles from the flue gas, which expands in a gas turbine (bottom center) and then (center right) passes through a heat recovery steam generator (the turbine and steam generators constitute the "combined cycle"). Finally, the gases are directed through a conventional particulate removal device (ESP or baghouse) before they reach the stack (right).

- *Cost-effectiveness.* Projections of capital costs for PFBC range from US$1200 to 1550/kW (equivalent to or up to 20 percent less expensive than pulverized-coal with wet scrubbers). However, PFBC has other advantages over pulverized-coal with scrubbers: fuel flexibility, modularity, and suitability for retrofit.

Construction. Time for construction can be reduced by up to 2 years (relative to PC with scrubbers) using shop fabrication and modular construction. Therefore, a 70 MW PFBC plant can be built in 2 to 4 years.

Suitability. PFBC technology is particularly suitable for most coals available in developing countries, but technology demonstration may be needed. Local manufacturing may not be feasible for the key components (boiler pressure vessel, hot-gas cleanup system, and gas turbine) because of the need for specialized equipment and highly trained personnel. As such, a larger percentage of the capital costs may be required in foreign currency (as compared to that for PC with scrubbers).

Deployment. Some risks still remain associated with the performance of key PFBC components. Further demonstration of the performance, reliability, and cost-effectiveness of these technologies is needed in developed countries. Additional demonstration projects with different coals are needed in developing countries.

Coal Gasification Technologies

Integrated Gasification Combined-Cycle

Because of its high cost and early stage of development, IGCC technology is, for the near future, an unlikely choice of technology for developing countries with lenient SO_2 removal and NO_x emission regulations. However, it is one of the few technologies (the other being PFBC) that significantly increases power plant efficiency and will have a beneficial effect in reducing emissions of CO_2. As such, IGCC, like PFBC, is a technology that may be used in developing countries in the long term.

Technology. Coal gasification is a process that converts solid coal into a synthetic gas composed mainly of carbon monoxide and hydrogen. Coal can be gasified in various ways by properly controlling the mix of coal, oxygen, and steam within the gasifier. There are also several options for controlling the flow of coal in the gasification section (e.g., fixed-bed, fluidized-bed, and entrained-flow systems; see Figure 4.3). Most gasification processes being demonstrated use oxygen as the oxidizing medium.

IGCC, like PFBC, combines both steam and gas turbines ("combined cycle"). Depending on the level of integration of the various processes (see Figure 4.4), IGCC may achieve 40 to 42 percent efficiency.

The fuel gas leaving the gasifier must be cleaned (to very high levels of removal efficiencies) of sulfur compounds and particulates. Cleanup occurs after the gas has been cooled, which reduces overall plant efficiency and increases capital costs (see Figure 4.4), or under high pressure and temperature (hot-gas cleanup), which has higher efficiency. However, hot-gas cleanup technologies are in the early demonstration stage.

Figure 4.3 Generic Coal Gasification Reactors

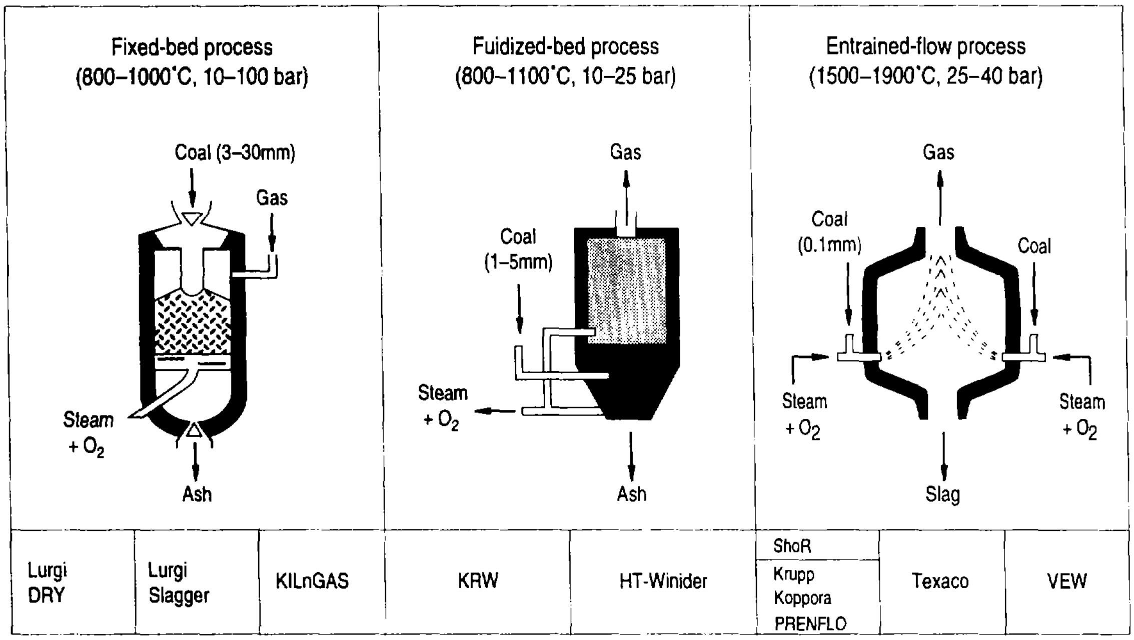


Figure 4.3 shows the main three coal gasification processes: Left: fixed bed; center: fluidized bed; and right: entrained flow.

Figure 4.4 Highly Integrated Gasification Power Plant Configuration

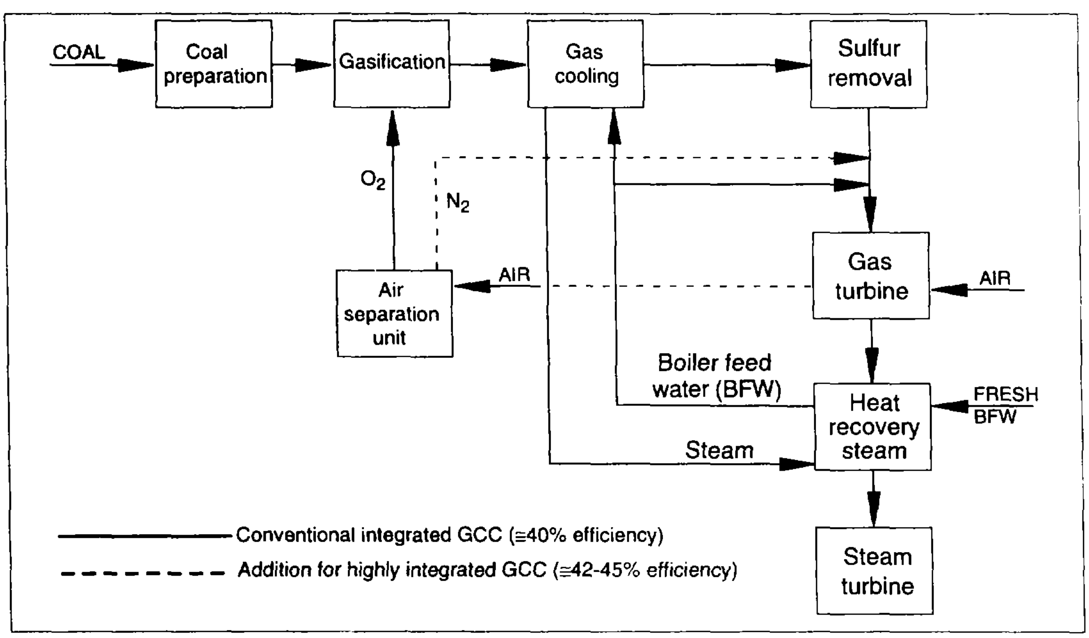


Figure 4.4 shows a typical IGCC process. Plant efficiency can be improved further by injecting the nitrogen from the air separation unit into the fuel gas before the gas turbine and using air from the gas turbine/compressor in the air separation unit (dotted lines).

After the fuel gas has been cleaned, it is burned and expands in a gas turbine. Steam is generated and superheated in both the gasifier and the heat recovery unit downstream from the gas turbine. The fuel gas is then directed through a steam turbine to produce electricity.

Performance. IGCC plants can achieve up to 45 percent efficiency, greater than 99 percent SO_2 removal, and NO_x below 50 ppm.

Availability. The following points describe the commercial conditions under which integrated gasification combined-cycle technology is available today.

- *Technology readiness.* IGCC is in the demonstration phase. After the completion of the 100 MW IGCC demonstration at Cool Water, California, in the United States (5-year program completed in 1989), a number of other demonstration projects have entered the design or demonstration phase in Europe, Japan, and North America.

  Most of these projects use entrained gasifiers (e.g., Texaco, Dow, and Shell technologies). However, the U.S. Department of Energy's Clean Coal Technology Program has selected two projects (Sierra Pacific's Piñon Project (80 MWe IGCC) using Kellogg technology, and the Tom Creek project (107 MWe IGCC) using the U-Gas technology developed by IGT), that are suitable for high-ash coals (such as those found in India and China). Also, a demonstration of Rheinbraun AG's HT Winkel fluidized-bed gasification process is planned in Europe. The results of these demonstration projects will be critical for assessing further the feasibility of these technologies for developing countries.

- *Suppliers.* A list of IGCC suppliers is provided in Annex B, Table B.8.

- *Cost-effectiveness.* IGCC cost projections range from US$1500 to 1800/kW; 10 to 20 percent higher than for pulverized-coal with wet scrubbers. IGCC technology may be the technology of choice when high SO_2 removal (e.g., 99 percent or higher) and low-NO_x emissions (below 100 ppm) are required.

Construction. Time for construction is expected to be similar to PC with wet FGD. However, phased construction (building of the gas turbine first, followed by the gasifier) can improve the economics of the IGCC plant by producing power as soon as the gas turbine is constructed.

Suitability. IGCC technology is in the early demonstration phase and is more expensive than competing alternatives. Entrained IGCC technologies are suitable for low-ash coals. High-ash coals, such as those in India, would require fluidized-bed gasification processes.

Deployment. The primary constraints to the application of gasification and IGCC plants in developing countries are that the technology needs further demonstration, the costs are higher than those of competing technologies, and the fact that environmental regulations in developing countries do not require the high SO_2 removal and low-NO_x emissions achieved by IGCC.

Coproduction of Electricity and Clean Fuels

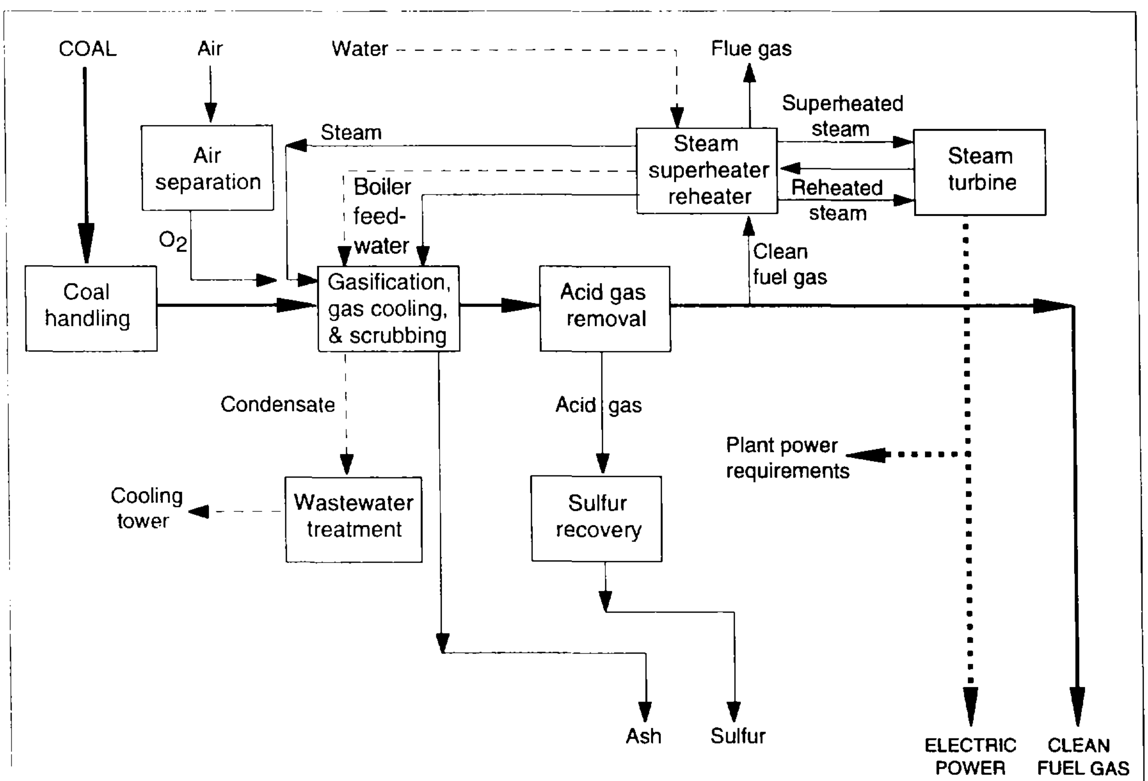
Because of the high cost of technology for the coproduction of electricity and clean fuels and its low cost-effectiveness at present price levels for coal and natural gas, it is currently not a suitable technology choice for developing countries.

Technology. Coproduction of electricity and clean fuels, such as methanol and gasoline, can be accomplished through the combination of coal gasification technology with other processes. Some potential applications, in addition to electricity generation, are as follows:

- Production of medium-Btu gas for industrial users
- Production of synthesis gas (hydrogen and carbon monoxide) for manufacturing of ammonia, methanol, and other chemicals
- Production of gasoline and other distillate fuels.

A generalized process flow diagram of coal gasification for coproduction of electricity and gas is shown in Figure 4.5.

Figure 4.5 Generalized Flow of Coal Gasification for Production of Fuel Gas



The system shown in Figure 4.5 differs from that shown in Figure 4.4 in that it uses only part of the fuel gas generated by the coal gasification process to produce electricity; the rest may be processed further to produce gasoline and distillate fuels or used as it is by the process industry.

The gas produced by a plant with a flow such as that shown in Figure 4.5 could be processed further to produce gasoline and distillate fuels. Similar arrangements are needed to produce synthesis gas.

Availability. The following points describe the present state of commercial development for coproduction technology.

- *Technology readiness.* A number of alternative technologies have been demonstrated, but are not fully commercialized.
- *Cost-effectiveness.* Coproduction processes using coal gasification are not cost-effective at present fuel prices (oil below US$20/barrel and natural gas below US$4/MBtu). Most technologies are expected to become cost-effective when oil prices exceed the US$40 to 50/barrel level.

Suitability. These coproduction technologies are not considered suitable for developing countries because they are in the early stages of development and their costs are high relative to those of conventional power generation methods.

Advances in Pulverized-Coal Output and Efficiency

To present a balanced picture of the coal-fired power generation and environmental control technologies, it is essential to mention developments in conventional pulverized-coal technology, which is used widely throughout the world. Whereas the clean coal technologies described in chapters 2 and 3 are developments directed at improving the environmental performance of pulverized-coal technology, other developments are enhancing its cost-effectiveness and overall efficiency. These include technological advances in design, control, and fault diagnosis, cutting-edge advances in thermodynamic efficiency, and wider applications of advanced plant rehabilitation and life-extension methods.

The purpose of this section is not to provide a complete review of these aspects but to raise the level of awareness about advances that need to be taken into account in comparing coal-fired technologies. More detailed assessment of pulverized-coal technology, as it pertains to utilization in developing countries, is needed.

Technology Advances

Significant improvements have been made in three main technical areas: improvements of the power plant design, instrumentation, and maintenance.

Design. The following improvements in the design of power plants are noteworthy for application in developing countries.

- Dynamic pulverizer classifiers for improved coal fineness and better combustion efficiency
- New types of air heaters (e.g., plate-type and heat pipe)

- Corrosion-resistant alloys or coatings (e.g., Cr-9 and 3.5 NiCrMoV steels), which make power plants more reliable

Instrumentation and Controls. Advances here include the following:

- Performance monitoring and optimization systems
- Digital controls
- Instrumentation for coal flow and size distribution measurement, acoustic pyrometry for furnace temperature measurements, unburned carbon loss monitoring and on-line coal quality monitoring
- Continuous emission monitoring equipment (especially for CO, O_2, CO_2, and NO_x).

Predictive and Preventive Maintenance. Systematic maintenance techniques are used widely in industrialized countries to minimize forced outages and maximize power plant output. With the rapidly increasing power and decreasing costs of personal computers, a variety of software has been developed and made available to the power industry at affordable cost.

A number of technologies have been developed also to provide early diagnosis of equipment deterioration and prediction of remaining life (next failure). Diagnostic monitoring equipment for rotating machinery (pulverizers, turbines, fans, and pumps) and pressure part components (e.g., boiler tubes) are commercially available and can assist the power plant operator in predicting when these components will fail and in taking preventive measures to avoid unit forced outages.

Thermodynamic Cycle Improvements. Recent thermodynamic cycle improvements include the utilization of supercritical, double-reheat steam cycles and once-through/variable pressure boilers with spiral-wound waterwalls, which have raised the plant efficiency to the 41 to 43 percent level (based on low heating value). Also, research has been initiated in many industrialized countries (Europe, Japan, and the United States) to integrate pulverized-coal technology with gas turbines into combined cycles with higher overall plant efficiency. However, these efforts are still in the pilot-stage and are not considered suitable for developing countries.

Life Extension/Rehabilitation

Use of diagnostic monitoring equipment for power plant life extension (rehabilitation) is, very often, the most cost-effective option available. Power plant reliability and, therefore, unit output (MW), decrease with time, even in well-maintained units. According to EPRI (no date-b), availability may drop from nearly 80 percent at the 20th year of operation to about 50 percent after the 30th year, to less than 30 percent after the 40th year. Poor maintenance accelerates the decline in reliability and output. Moreover, as one would expect, the expenses of refurbishment increase as the system output and availiability decline. On the other hand, an effective enhanced maintenance program can keep system availability at 80 percent or better over the life of the plant.

Life extension/rehabilitation methods have advanced significantly during the last two decades. Such methods apply to all critical power plant components (pulverizers, boiler, turbines, and balance-of-plant equipment) and include replacement of parts (e.g., air heater baskets and boiler economizer section) or whole components (e.g., replacement of low-pressure steam turbine), coatings with new materials (e.g., erosion-resistant coatings of boiler tubes), and installation of additional components (e.g., dynamic classifiers on the pulverizers).

Steam turbine and generator manufacturers have confirmed that considerable design margin exists in old (pre-1965) turbines, which can be refurbished to increase output with relatively small cost (Miliaras 1991). This output increase can be accomplished with design improvements such as

- Enhancement in steam admission and flow-path design geometry
- Replacement of several rows of last-stage blades with those of a more advanced design (before the early 1960s, blades were designed using two-dimensional flow theory; now, more advanced flow analysis has improved blade designs).
- Improved generator insulation
- Advanced controls.

Technology Readiness

Most technologies mentioned above are commercially available in industrialized countries and are highly suitable for developing countries. However, a lack of awareness about these technologies, as well as lack of incentives to improve power plant performance and methods to evaluate and plan life extension/rehabilitation projects, limit their utilization in developing countries.

Recommendation

Assessment of the status and suitability of the power plant life extension and rehabilitation technologies for developing countries is needed. It should include

- Status of the key technologies
- Suitability for developing countries and selection of the most suitable technologies
- Information on commercial availability
- Guidelines on how developing countries should evaluate and utilize key technologies
- Case studies (examples from specific power plants in developing countries).

5

Relationship between Environmental Regulations and Technology Choice

As described in chapters 2 to 4, each clean coal technology is capable of achieving a different level of emission reduction at a different cost level; or, for a given emission level required by environmental regulations, one or more technologies may satisfy the emission criterion in a cost-effective manner. Therefore, technology choice is closely tied to environmental requirements. The link between required removal of SO_2 and most cost-effective technology choice is summarized in Table 5.1 The most cost-effective processes for required levles of NO_x removal are shown in Table 5.2

Table 5.1 Most Cost-Effective Processes for SO_2 Removal

Required SO_2 removal (%)	*Most cost-effective processes*
≤ 30	Coal cleaning (depending on coal characteristics)
30 to 70	Dry sorbent injection (furnace sorbent injection, duct injection, dry scrubbers [FGD])
70 to 90	Atmospheric fluidized-bed combustion and dry scrubbers (FGD)
80 to 95	Atmospheric and pressurized fluidized-bed combustion and wet scrubbers (FGD)
>95	Integrated gasification combined cycle, wet scrubbers and pressurized fluidized-bed combustion

Note: FGD = flue-gas desulfurization.

Table 5.1 indicates that for each level of SO_2 removal, different technologies should be selected as more cost-effective.

Table 5.2 Most Cost-Effective Processes for NO_x Removal

Required NO_x reduction (%)	*Most cost-efffective processes*
30 to 60	Low-NO_x burners with or without overfire air are the most cost-effective. Similar NO_x reduction can be achieved with selective noncatalytic reduction and reburning, but these technologies are more expensive than low-NO_x burners.
50 to 70	Low-NO_x burners with reburning or SNCR are the most suitable technologies.
70 to 90	Selective catalytic reduction is the technology of choice.

Note: SNCR = selective noncatalytic reduction.

Because each technology has a different level of emissions (e.g., SO_2, NO_x, CO_2, particulates, solid wastes), statements regarding its attractiveness ("this is the technology of choice") should be accompanied by the main environmental requirements (e.g., SO_2 removal, NO_x emissions, particulate removal).

Sample environmental regulations of different countries are provided in Annex A.

6

Suitability of Clean Coal Technologies: A Screening Method

The most suitable technologies for each developing country and each project are unique. To identify the technology best suited for a particular situation, a number of criteria must be considered. This brief chapter lists some criteria for evaluating the suitability of CCTs and provides a general rating of the main technologies in tabular form.

Evaluation Criteria

The primary criteria for evaluation are listed below:

- Technology readiness
- Suitability for the characteristics of the coal to be used
- Suitability for environmental requirements (SO_2 removal, NO_x emissions, particulate removal, solid waste generation and disposal, and plant efficiency)
- Desirability of modular construction
- Capital and O&M costs
- Applicability to existing and new power plants
- Capability of indigenous personnel to specify, procure, design, manufacture, and operate the plant
- Impact on foreign exchange requirements.

A technology evaluation begins by checking and clarifying the criteria listed above. The next step is to identify all the relevant power generation and environmental control technologies. Finally, one can move on to evaluate each technology relative to the criteria and select the most appropriate technologies. These steps are discussed in detail below:

- *Readiness.* The technology should be commercially available in industrialized countries; at least 3 to 5 utility scale facilities (100 MWe or larger) should be in operation, demonstrating the successful implementation of the technology.

- *Suitability.* The technology should be suitable for the characteristics of the coal(s). Minor adaptation of the technology to the unique characteristics of certain coals would not be perceived as a major disadvantage. However, if major design changes are required, this would not reflect favorably on the technology.
- *Performance.* Parameters include SO_2 removal efficiency, NO_x generation, particulate emissions, solid waste generation, and plant efficiency (heat rate or CO_2 emissions).
- *Modularity.* Most developing countries will prefer prefabricated, easy-to-install modules, usually up to 100 to 200 MW each.
- *Costs.* Both capital and O&M (operating and maintenance) costs must be considered.
- *Applicability.* This indicates whether the technology is suitable for new power plants or retrofit applications. Considering that life extension and rehabilitation of existing power systems is of primary importance, in developing countries, technologies that are applicable for both new plants and retrofits would receive higher ratings.
- *Indigenous capability.* This relates to the ability to train local personnel easily in the process and power plant design, to develop the necessary manufacturing capability, and to be able to operate and maintain the facility.
- *Foreign exchange impact.* This relates to the foreign exchange requirements for technology acquisition, training, and purchasing of power plant components that cannot be manufactured in developing countries. (Note: a high rating means a small impact on foreign exchange requirements.)

The total rating reflects the cumulative score of all criteria considered and is accompanied by an indication of the applicability of a technology for short- or long-term applications. The total rating can be developed either by comparing the ratings of the technologies relative to each criterion or by assigning a weighting factor to each of the ratings (e.g., 1 for low, 2 for medium, and 3 for high).

Relevant Technologies

Table 6.1 summarizes the ratings of the technologies described in chapters 2 to 4. It should be noted that the rating, according to the above criteria, and the selection of the most promising technologies are to illustrate the methodology. The results are not applicable to all countries. However, they are based on realistic requirements and could be applicable to most developing countries.

Use of the word *long-term* means that the technology is either in the early stages of development in industrialized countries or needs extensive adaptation to the unique requirements of developing countries, which usually takes more than three to five years. It does not mean, however, that there is nothing to be done in the near future.

Table 6.1 Clean Coal Technologies for Developing Countries

Technology	Readiness	Suitability	Reduction of SO_2	Reduction of NO_x	Reduction of PM	Solid waste	Plant efficiency	Modularity	Capital costs	O&M costs	Applicability: New units	Applicability: Existing units	Indigenous capability: Process and design	Indigenous capability: Mfg.	O&M capability	Foreign exchange impact	Total rating	Term
Physical coal cleaning	●	●	●	n.a.	**O**	**O**	○	●	●	**O**	Y	Y	○	●	●	●	●	S
Low-NO_x burners	●	●	n.a.	●	**O**	n.a.	**O**	n.a.	●	●	Y	Y	**O**	●	●	●	●	S
Sorbent injection	**O**	●	**O**	n.a.	n.a.	○	n.a.	n.a.	●	**O**	Y	Y	○	**O**	**O**	**O**	●	S
Duct injection	**O**	●	**O**	n.a.	n.a.	○	n.a.	n.a.	●	**O**	Y	Y	○	**O**	**O**	**O**	●	S
Dry scrubber	**O**	●	●	n.a.	n.a.	○	n.a.	●	**O**	**O**	Y	Y	○	**O**	**O**	**O**	**O**	S
Wet scrubber	●	**O**	●	n.a.	n.a.	○	○	○	○	●	Y	Y	○	**O**	○	**O**	○	L
SNCR	○	**O**	n.a.	**O**	n.a.	n.a.	**O**	n.a.	**O**	**O**	Y	Y	○	**O**	**O**	**O**	○	L
SCR	●	**O**	n.a.	●	n.a.	n.a.	**O**	●	○	○	Y	Y	○	○	○	○	○	L
$DeSO_x/DeNO_x$	○	—	●	●	n.a.	—	—	—	○	○	Y	Y	○	○	○	○	○	L
Advanced ESP	●	●	n.a.	n.a.	●	**O**	n.a.	●	●	●	Y	Y	**O**	●	●	●	●	S
Bag filter	●	●	n.a.	n.a.	●	**O**	n.a.	●	**O**	**O**	Y	Y	**O**	**O**	**O**	**O**	**O**	S
Hot-gas clean-up	○	—	n.a.	n.a.	●	n.a.	n.a.	●	○	○	Y	N	○	○	○	●	○	L
Bubbling AFBC	●	●	●	●	n.a.	○	**O**	●	**O**	**O**	Y	Y	**O**	●	**O**	**O**	●	S
Circulating AFBC	●	●	●	●	n.a.	○	**O**	●	**O**	**O**	Y	N	○	●	**O**	**O**	●	S
PFBC	**O**	●	●	●	n.a.	○	●	●	○	**O**	Y	Y	○	○	○	○	**O**	L
Entrained IGCC	○	●[a]	●	●	●	●	●	●	○	○	Y	N	○	○	○	○	○	L
Fluidized bed IGCC	○	●[b]	●	●	●	●	●	●	○	○	Y	N	○	○	○	○	○	L
Large subcritical PC	●	●	n.a.	n.a.	n.a.	n.a.	**O**	○	**O**	**O**	Y	N	●	●	●	**O**	●	S
Large supercritical PC	●	●	n.a.	n.a.	n.a.	n.a.	●	○	○	**O**	Y	N	○	○	○	○	**O**	L
Plant life extension	●	●	n.a.	n.a.	n.a.	n.a.	●	n.a.	●	●	N	Y	**O**	●	**O**	**O**	●	S

● High rating (good performance, low cost, good capability, low impact on foreign exchange)
O Medium rating
○ Low rating

— = Data not available
Mfg. = manufacturing
n.a. = Not applicable
PM = particulate matter
L = long
S = short
Y = yes
N = no

[a] For high-heating-value coals only. [b] For lignites and high-ash coals only.

7

Conclusions and Recommendations

Many clean coal technologies are available or in development, including coal cleaning; improved or new methods for coal combustion; environmental control technologies (add-ons to existing plants); and advanced methods for using coal in environmentally cleaner ways (fluidized-bed combustion, gasification, and coal-derived clean fuels). These technologies have been developed primarily in industrialized countries, although some have been demonstrated adequately in the industrialized countries and can be considered as available for use in developing countries. Ultimately, the choice of a particular technology for a specific country must take into account the close relationship between a proven technology and that country's environmental needs and regulations.

Technology Choices for Developing Countries

Considering the environmental regulations of most developing countries, the state of development of clean coal technologies, the limited financial resources available in developing countries, and other factors, it is worth summarizing the technologies that have been identified as suitable for short- and long-term applications in developing countries.

Technologies for Short-Term Applications

Technologies suitable for the short term include the following:

- Conventional physical coal cleaning
- Low-NO_x combustion technologies
- Sorbent and duct injection
- Dry scrubbers
- Circulating AFBC
- Advanced electrostatic precipitator technologies

- Bagfilters (only when sorbent/duct injection and AFBC technologies are also introduced)
- Large subcritical pulverized-coal and life extension/rehabilitation technologies.

Technologies for Long-Term Applications

Technologies suitable for application in the long term include the following:

- Pressurized fluidized-bed combustion (PFBC)
- Large supercritical pulverized coal
- Wet scrubbers (flue-gas desulfurization).

This selection is generic and may not be applicable to all developing countries. Country-specific assessments are recommended to identify the most suitable technologies and the specific actions to be undertaken.

Additional Recommendations for Developing Countries

The following additional recommendations are offered on appropriate clean coal technologies for developing countries:

- *Physical coal cleaning technologies are easily adaptable for use in developing countries and are cost-effective in most cases.* Coal cleaning reduces transportation costs, sulfur and particulate emissions, and improves power plant reliability. Developing countries are urged to adopt coal pricing policies that reflect the quality of the coal and its impacts on power production costs and emission generation.
- *Low-NO_x burners should be included in the design specifications of all future power plants and provisions should be made for overfire air ports.* Such specifications will not increase the power plant costs by more than US$5 per kW, but they will result in significant savings when future environmental regulations require further NO_x reductions.
- *Efficient operation of power plants, especially when NO_x emissions must be minimized, is as important as installation of low-NO_x burners.* Therefore, power plant operators must be trained and supplied with the appropriate power plant instrumentation, controls, and optimization software needed to keep NO_x emissions low.
- *Dry scrubbers and sorbent injection technologies offer an attractive alternative to developing countries through which moderate sulfur removal can be achieved at relatively low cost.* However, further demonstration of most sorbent-based technologies will be required in developing countries.

- *Electrostatic precipitator technology has undergone significant advances and should be introduced more vigorously into developing countries.* This technology also has a short payback period (1 to 5 years).
- Bagfilters may be required in developing countries, especially if technologies such as sorbent injection, dry scrubbers, and fluidized-bed combustion are used.
- *Atmospheric fluidized-bed combustion technology, especially the circulating type, is particularly suitable for developing countries.* Use of this technology should be promoted.

Recommendations for the World Bank

To promote the use of environmentally benign technologies without encouraging developing countries to select high-risk/high-cost technologies, the following actions are suggested:

- *Develop a set of criteria that must be met by each technology before it can qualify for use in developing countries.* One criterion, for example, could require that the technology have been used in at least five to ten power plants of 100 MW or larger in industrialized countries, and that it has performed well and reliably. Another criterion would require that the technology have demonstrated good performance with a coal similar to the coal to be used for projects in developing countries.
- *Perform a technology risk assessment that identifies the risks associated with the technology and proposes a risk management plan.* Such an assessment should identify all the risks, as well as their source, and provide ways to minimize them or manage them. For example, in some cases, the technology developers would be willing to accept the technology-related risks through equity-participation or special guarantee arrangements.
- *Initiate a study to assess the cost-effectiveness of power plant life extension/rehabilitation technologies.* This would be a prelude for identifying the most suitable technologies for developing countries, and developing guidelines on how to screen and select the best options.

Annex A
Sample Environmental Regulations in Selected Countries

Table A.1 Standards of Ambient Air Quality and Emissions in Asian Countries

(Unit: mg/m^3, unless otherwise indicated)

Pollutant	*Country*	*Annual average*	*24-hour maximum*	*Daily average*
SO_2	China	0.06	0.50	0.15
	India			
	Indonesia			0.26(0.1ppm)
	Philippines		0.85 (0.3ppm)[a]	0.37 (0.14ppm)
	Thailand	0.10		0.30
	(Reference)			
	World Bank	0.10	0.5 (Outside)	-
				1.0 (inside)
	USA	0.06(0.02ppm)[b]	0.26 (0.1ppm)[b]	
		0.08 (0.03ppm)[c]	0.365 (0.14ppm)[c]	
			1.3 (0.5ppm)[b d]	
	FRG	0.14 (0.05ppm)		0.40 (0.14ppm)
	Japan		0.26	0.11 (0.04ppm)
NO_x	China		0.15	0.1
	India			
	Indonesia			0.093 (0.05ppm)
	Philippines		0.19 (0.1ppm)[a]	
	Thailand		0.32[a]	
	(Reference)			
	World Bank	0.1 (0.05ppm)		
	USA	0.1 (0.05ppm)		
	FRG	0.1 (0.05ppm)		0.30 (0.15ppm)
	Japan			0.04-0.06
Dust	China		1.00[e]	0.30[e]
			0.50[f]	0.15[f]
	India			
	Indonesia			0.26
	Philippines		0.25[a]	0.15
	Thailand	0.10		0.33
	(Reference)			
	World Bank	0.10	0.50	
	USA	0.065[b]	0.15[b]	
		0.075[c]	0.26[c]	
	FRG	0.1[g]		0.2[g]
		0.2[h]		0.4[h]
	Japan		0.20	0.1

Source: (Kataoka 1993).

[a] 1-hr average. [b] Secondary-based on environmental effects. [c] Primary-based on health effects on humans. [d] max 3-hr-once yearly. [e] Total suspend. [f] Fly dust. [g] <10um. [h] <10um.

Table A.2 Air Emission Standards for Large (> 50 MW) Coal-Fired Boilers

(Unit: mg/Nm^3)

Country/region	*Suspended particulates*	*Nitrogen oxides*	*Sulfur oxides*
Australia	80	500;[a] 800 (>30 MW)[b]	2,000
Austria	50	200 (>300 MW); 250 (>300 MW FBC boilers); 300 (150–300 MW); 400 (50–150 MW)	200
Belgium	50	650 (>300 MW); 400 (50–300 MW)[c]	200 (>300 MW);[d] 400 (>300 MW);[e] 1,200 (100–300 MW); 2,000 (50–100 MW)
Bulgaria			650
Canada	125 (43 g/GJ)	740 (258 g/GJ)	715 (250 g/GJ)
China	200; 400; 600[f]		Calculated according to the formula $q = P \times 10^{-6} \times He^2$ where P is a factor specified by regulation to various regions and He equals stack height.[g]
Czech Republic	100	650	500 (>300 MW); 1,700 (50–300 MW)
Denmark	50	200	400 (>500 MW); 2,000–400 (101–499 MW, sliding scale); 2,000 (<100 MW)
European Union	50 (>500 MW); 100 (<100 MW)	650; 1,300[h]	400 (>500 MW); 2,000–400 (101–499 MW, sliding scale); 2,000 (<100 MW)[i]
Finland	60 (20 g/GJ)	135 (>300 MW), (50 g/GJ); 405 (50–300 MW) (150 g/GJ)	380 (>150 MW); (140 g/GJ); 620 (50–150 MW); (230 g/GJ)
France	50 (>500 MW); 100 (<500 MW)	650 (>50 MW); 1,300 (>50 MW)[j]	400 (>500 MW);[k] 800 (400–500 MW);[l] 2,400-4xMW (100–500 MW)[m]
Germany[n]	50	200 (>300 MW); 400 (50–300 MW)	400 (>300 MW) and 85% sulfur removal; 2,000 (100–300 MW) and 60% sulfur removal; 2,000 (50–100 MW)
India[o]	150 (>210 MW);[g] 350 (<210 MW)		
Indonesia[p]	400–600	170–460	570–866[q]
Italy	50	200 (>500 MW); 300 (300–500 MW utility FBC boilers); 650–200 (300–500 MW, sliding scale); 650 (50–300 MW)	400 (>500 MW); 800 (>400 MW); 1,600–400 (200–500 MW, sliding scale); 2,000–1,600 (100–200 MW, sliding scale); 2,000 (50–100 MW)

Continues on next page

Table A.2 (continued)

Country/region	*Suspended particulates*	*Nitrogen oxides*	*Sulfur oxides*
Japan	50 (>200,000 Nm^3/ hr gas emission); 100 (40,000–200,000 Nm^3/hr gas emission); 150 (<40,000 Nm^3/hr gas emission)	410 (>700,000 Nm^3/hr gas emission), (200 ppm); 510 (40,000–700,000 Nm^3/hr gas emission),[r] (250 ppm); 720 (<40,000 Nm^3/hr gas emission), (350 ppm)	Set individually according to the formula $K \times 10^{-3} \times He^2 = (m^3/h)$ K = area constant; He = stack height (m). Range: 170–860 (60–300 ppm)
Korea[s]	250	875, (350 ppm)	2,200, (700 ppm)
Netherlands	50	200 (>300 MW); 500[t] (<300 MW)	200 (>300 MW) and 90% sulfur removal by FGD; 700 (<300 MW)
New Zealand[u]	125;[v] 250[w]	410, (200 ppm)	125
Philippines[x]	150;[y] 200[z]	1,000; (350 g/GJ)	1,500; (573 ppm)
Poland	190–600; (70–1,370 g/GJ)[aa]	100–490, (35–170 g/GJ)[bb]	540–1,760, (200–650 g/GJ)[cc]
Romania			400 (>500 MW); 2,000–400 (100–500 MW, sliding scale); 2,000 (50–100 MW)
Spain	50 (>500 MW); 100 (50–500 MW)	650; 1,300[dd]	400 (>500 MW); 2,000–400 (101–499 MW, sliding scale); 2,000 (50–100 MW)[ee]
Sweden	50	80 (>300 MW); (30 g/GJ); 135 (<300 MW); (50 g/GJ)[ff]	160 (>500 MW); (30 g/GJ); 270 (<500 MW); (50 g/GJ)
Switzerland	50	200 (>300 MW); 400 (50–300 MW)	400 (>100 MW) and 85% sulfur removal; 400 (<100 MW)[gg]
Taiwan	25–500[hh]	720–1,025; (350–500 ppm)	1,430–3,145; (500–1,400 ppm)[ii]
Thailand[jj]	400	940, (500 ppm)	1,300, (500 ppm)
Turkey	150[kk]	800; 1,800[ll]	400 (<300 MW FBC boiler); 1,000 (>300 MW); 2,000 (<300 fixed bed boiler)
United Kingdom[mm]	50 (>500 MW); 100 (50–100 MW)	650	400 (>500 MW); 2,000–4(MW-100) (100–500 MW); 2,000 (50–100 MW)[nn]
United States	60; (0.05 lb/MBtu)	615–740; (0.5–0.6 lb/MBtu, and 65% removal)[oo]	1,480 (>73 MW), (1.2 lb/MBtu)[pp]

Continues on next page

Table A.2 (continued)

Units of measure: MW = megawatt; mg/Nm^3 = milligrams per normal cubic meter; g/GJ = grams per Gigajoule; lb/MBtu = pounds per million British thermal unit; ppm = parts per million parts of flue gas.

Conversion factors: 1 mg/Nm^3 = 2.86 g/GJ; 1 mg/Nm^3 = 1,230 lb/MBtu; 1 mg/Nm^3 NO_X = 2.05 ppm NO_X; 1 mg/Nm^3 SO_2 = 2.86 ppm SO_X.

Note: Table A.2 was compiled by Ms. Magda Lovei, World Bank Environment Department.

Source: Except as otherwise indicated, the source for suspended particulates and NO_X standards is Soud (1991) and that for SO_2 standards is International Energy Association (1993).

a. Applicable to industrial plants.

b. Applicable to utility plants.

c. Standards applicable to plants built after December 31, 1995:
- 200 mg/Nm^3 (>100 MW)
- 400 mg/Nm^3 (50–100 MW).

d. Post-1995 standard, applicable to plants for which first application for authorization was submitted after June 3, 1987.

e. Pre-1995 standard, applicable to plants for which first application for authorization was submitted before June 3, 1987.

f. Applicable to Class I–III areas, respectively (Resources for the Future, 1992):
- Class I: nature reserves, scenic spots, places of historic interest
- Class II: urban areas, suburbs, industrial areas
- Class III: other places.

g. Dingrong (no date).

h. Applicable to fuels with less than 10 percent volatile compounds.

i. For combustion plants firing indigenous high- or variable-sulfur coal, the following standards apply:
- 90 percent removal (>500 MW)
- 60 percent removal (<300 MW)
- 40–90 percent removal sliding scale (167–499 MW)
- 40 percent removal (100–166 MW).

j. Applicable to fuels with less than 10 percent volatile compounds.

k. Plants that, because of special characteristics of the coal, cannot meet the set standards must achieve 90 percent sulfur removal.

l. Applicable to plants with less than 2,200 hours/year operating time.

m. Plants that use domestic coal and, because of special characteristics of the coal, cannot meet the set standards should achieve
- 40 percent sulfur removal (100≤167 MW) and
- (0.15 MW + 15) percent sulfur removal (167≤500 MW).

n. International Energy Agency (1992).

o. Government of India (1986).

p. Budihardjo (1993).

q. In SO_3.

r. Applies where construction started after April 1, 1987. International Energy Agency (1992).

s. Moon (1993).

t. For PF boilers licensed after 1993, applicable standard is 100 mg/m^3.

u. International Energy Agency (1992).

v. Applicable to large emitters.

Continues on next page.

Table A.2 (continued)

w. Applicable to small and medium emitters.
x. Philippines Department of Natural Resources (1993).
y. Applicable to urban and industrial areas.
z. Applicable to other areas.
aa. Lowest standard applicable to PF wet bottom boilers firing lignite, highest to stationary stroker boilers firing hard coal.
bb. Depending on coal type and removal technology.
cc. Depending on coal quality and furnace type.
dd. Applicable to fuels with less than 10 percent volatile compounds
ee. Additional standards:

- utility plants firing indigenous coal: 60 percent sulfur removal
- utility plants firing imported coal: 800 mg/Nm^3
- plants firing indigenous high or variable sulfur coal: 60 percent sulfur removal.

ff. Additional guidelines:

- combustion plants emitting more than 300 t NO_X per year: 135–270 mg/m^3 (100–200 g/GJ)
- combustion plants emitting less than 300 t NO_X per year: 270–540 mg/m^3 (100–200 g/GJ).

gg. Additional requirements for FBC boilers under 100 MW: 75 percent sulfur removal.
hh. Limits depend on quantity of flue gas emitted and location of power plant.
ii. Additional standards for

- utility plants: 1,430–2,145 mg/m^3 (500–750 ppm)
- imported coal fired plants: 3,145 mg/m^3 (1,100 ppm)
- domestic coal fired plants: 4,000 mg/m^3 (1,400 ppm).

jj. Source: Chiewwattakee, 1993.
kk. Limit can be doubled by government permission for lignite-burning facilities. International Energy Agency (1992).
ll. For units using pulverized coal. International Energy Agency (1992).
mm. Her Majesty's Inspectorate of Pollution (1991).
nn. Additional standards for combustion plants firing indigenous high or variable sulfur coal:

- 90 percent sulfur removal (>500 MW)
- 40 + 0.15 (ME-166) percent sulfur removal (155–500 MW)
- 40 percent sulfur removal (100–166 MW)
- 2,250 mg/m^3 (50–100 MW individual boilers and furnaces).

oo. Depending on mine location and furnace type.
pp. Additionally, maximum achievable limits:

- greater than 90 percent sulfur removal: 1,480 mg/Nm^3 (1.2 lb/MBtu)
- ninety percent sulfur removal: 740–1,480 mg/Nm^3 (0.6–1.2 lb/MBtu)
- between 70 and 90 percent sulfur removal: 740 mg/m^3 (0.6 lb/MBtu).

Annex B
Equipment Suppliers

A general reference to U.S. suppliers is provided in the "93/94 Buyers' Guide Issue to Power Plant Products and Services," in *Power Engineering*, September 1993.

Table B.1 Suppliers of Coal Cleaning Technologies

Supplier name	*Headquarters (country)*	*Address*	*Contact person*	*Telephone number*	*Fax number*	*Notes*
AO Energomachexport	Germany					
Allen and Garcia Co.	United States					
Daniels Co.	United States					
Envirotech Coal Services Corp.	United States					
Heyl & Petterson, Inc.	United States					
Lively Mfg & Equipment Co.	United States					
McNally Pittsburgh, Inc.	United States					
Roberts & Schaeffer Corp.	United States					
Warman International Inc.	United States					

Note: Suppliers from other countries were not readily available at the time of preparation of this report. Countries such as Germany, United Kingdom and Australia have organizations providing coal cleaning technologies throughout the world.

Table B.2 Suppliers of Low-NO_x Combustion Technologies

Supplier name	*Headquarters (country)*	*Address*	*Contact person*	*Telephone number*	*Fax number*	*Notes*
Babcock Energy	United Kingdom					
International Combustion Ltd	United Kingdom					
Burmaister & Wain	Germany					
Steinmuller	Germany					
Mitsubishi HeavyIndustries	Japan					
Babcock-Hitachi	Japan					
ABB/CE	United States	Windsor, CT or Chattanooga, TN				
Babcock & Wilcox Corp	United States	Barberton, OH				
Foster Wheeler Corp.	United States	Livingston, NJ				
Pheonix Corp	United States					
Riley Stoker	United States	Boston, MA				
Pillard	France	13 Rue Raymond Teissere 13272 Marseille Cedex 08	Mr. Maurice Idoux, Export Manager	(33) 91 80 90 21	(33) 91 25 72 71	

Table B.3 Suppliers of Sorbent and Duct Injection Processes

Supplier name	*Headquarters (country)*	*Address*	*Contact person*	*Telephone number*	*Fax number*	*Notes*
Babcock & Wilcox	United States					
CONSOL Inc. (Coolside process)	United States					
Dravo Corp. (HALT process)	United States					
Bechtel Corp.[a]	United States					
Lurgi Corp.	Germany					
Wulff GmbH (Reflux CFB)						
Tampella Corp. of Finland (LIFAC)	Finland					
Airpol Inc. (AIRPOL)	United States					
Damp (ADVACATE)	United States					

[a] Markets the Confined Zone Dispersion (CZD) process.

Table B.4 Suppliers of Wet and Dry FGD Processes

Supplier name	*Headquarters (country)*	*Address*	*Contact person*	*Telephone number*	*Fax number*	*Notes*
ABB Environmental Systems	United States	Windsor, CT				
Air Products Inc.	United States	Allentown, PA				
Airpol, Inc.	United States					
General Electric Environmental Systems	United States	Schenectady, NY				
Joy Environmental Technologies	United States					
NaTec Resources, Inc.	United States					
Research Cottrell	United States	Atlanta, GA				
Wheelabrator Air Pollution Control	United States					
Chiyoda Corp.	Japan					
Flakt	Denmark					
Lurgi Corp.	Germany					
Tampella Power Corp.	Finland					
CNIM[a]	France	35 Rue De Bassano 75008 Paris	Mr. Guy Chanty, Export Manager	(33 1) 44 31 11 00	(33 1) 47 23 09 20	
LAB SA	France	Tour Credit Lyonnais 129 Rue Servient 69431 Lyon Cedex 03		(33) 78 63 70 90	(33) 78 60 94 87	
Procedair	France	25-27 Boulevard De La Paix 78100 St-Germain En Laye		(33 1) 39 73 92 15	(33 1) 39 73 09 17	
Genevet[b]	France	37 Blvd Malesherbes 75008 Paris	Mr. Michel Comte, Export Manager	(33 1) 42 65 91 72	(33 1) 42 65 63 04	
INOR[b]	France	8 Rue Henri Becquerel 92508 Rueil Malmaison Cedex		(33 1) 47 10 03 50	(33 1) 47 32 04 54	
GEC Alsthom Group Boilers & Environmental Systems Division	France	38 Avenue Kleber 75795 Paris Cedex 16		(33 1) 47 55 20 00	(33 1) 47 55 21 10	

[a] Postcombustion flue-gas cleaning (semi-wet limestone injection process for SO_2 neutralization).
[b] Postcombustion advanced flue-gas cleaning.

Table B.5 Suppliers of SCR Systems

Supplier name	*Headquarters (country)*	*Address*	*Contact person*	*Telephone number*	*Fax number*	*Notes*
ABB	United States					
Babcock & Wilcox	United States					
Cormetech, Inc.	United States					
Engelhard Corp.	United States					
Joy Environmental Systems	United States					
Norton Co.	United States					
Riley and Rhoen-Poulenc Inc.	United States					
Siemens	Germany					
GEC Alsthom Group Boilers & Environmental Systems Division	France	38 Avenue Kleber 75795 Paris Cedex 16		(33 1) 47 55 20 00	(33 1) 47 55 21 10	

Table B.6 Suppliers of Bagfilters

Supplier name	*Headquarters (country)*	*Address*	*Contact person*	*Telephone number*	*Fax number*	*Notes*
ABB Environmental Systems	United States					
Airpol, Inc.	United States					
Babcock & Wilcox Corp.	United States					
Electric Power Technologies	United States	Menlo Park, CA				
Fisher-Klosterman Inc.	United States					
Flex-Kleen Corp.	United States					
Fuller Co.	United States					
Hoffman Air & Filtration Systems, Division of Clarkson Industries, Inc.	United States					
Joy Environmental Technologies	United States					
Research Cottrell	United States	Atlanta, GA				
Southern Research Institute	United States	Birmingham, AL				
Wheelabrator Air Pollution Control	United States					
Zurn Air Systems	United States					
Flakt, Environmental Systems	Denmark					
Deutsche Babcock AG	Germany					

Table B.7 Suppliers of AFBC Boilers

Supplier name	*Headquarters (country)*	*Address*	*Contact person*	*Telephone number*	*Fax number*	*Notes*
Ahlstrom	Finland					
Pyropower	United States					
Foster Wheeler	United States					
Lurgi Corp.	Germany					
ABB/Combustion Engineering	United States					
Stein Industries	France	B.P. 74 78141 Velizy Villacoublay Cedex	Mr. Jacques Barthelemy, Export Director	(33 1) 34 65 45 45	(33 1) 34 65 43 99	
Gotaverken and Studsvik	Sweden					
Tampella Power Corp.	Finland					
Babcock & Wilcox	United States					
Combustion Power Corp.	United States					
Energy Products of Idaho	United States					
Keeler/Dorr-Oliver	United States					
Deutsche Babcock Werke	Germany					

Table B.8 Suppliers of IGCC Processes

Supplier name	*Headquarters (country)*	*Address*	*Contact person*	*Telephone number*	*Fax number*	*Notes*
Dow Chemical	United States					
GEC Alsthom Group Boilers & Environmental Systems Division	France	38 Avenue Kleber 75795 Paris Cedex 16		(33 1) 47 55 20 00	(33 1) 47 55 21 10	
M.W. Kellogg	United States					
Shell (USA)	United States					
Texaco	United States					
Institute of Gas Technology (IGT)	United States					

Notes:

European suppliers: British Gas, Lurgi, Shell and Rheinbraun AG (HT Winkel fluidized-bed gasification process).

Japanese suppliers: Mitsubishi is developing a air-blown entrained gasification process.

References

Budihardjo, Sayid, R.M. 1993. "Integrating Improved Coal Technologies into the Energy System." Paper presented at IEA Second International Conference on The Clean and Efficient Use of Coal and Lignite: Its Role in Energy, Environment and Life. Bangkok, 30 November – 3 December.

Bustard, C. J., and others. 1988. "Fabric Filters for the Electric Utility Industry." EPRI publication CS-5161; vol. 1: *General Concepts;* vol. 2: *Sonic Cleaning Guidelines.*

Canada Gazette. 1990. *Thermal Power Generation Emissions National Guidelines for New Stationary Sources.* Part I.

Carr, R. C., and W. B. Smith. 1984. "Fabric Filter Technology for Utility Coal-Fired Power Plants." EPRI publication CS-3724-SR, October.

Chang, R., and R. Altman. No date. "Advances in Particulate Control Technology." EPRI.

Chiewwattakee, Atthaya. 1993. "Reducing Environmental Impact From Using Coal and Lignite in Thailand." Paper presented at IEA Second International Conference on The Clean Efficient Use of Coal and Lignite: Its Role in Energy, Environment and Life. Bangkok, 30 November – 3 December.

Cichanowicz, E. 1990. "Engineering Evaluation of Combined NO_x/SO_2 Technologies." *EPRI Journal,* pp. 4–7.

Claussen, R. L., and others. 1993. "Engineering and Design Guidelines for Duct Injection Retrofits." Paper presented at the SO_2 Control Symposium, Boston, Massachusetts, August 24–27.

DePero, M. J., and others. 1993. "Final Results of the DOE LIMB and Coolside Demonstration Projects." Paper presented at the 2nd Annual Clean Coal Technology Conference, Atlanta, Georgia, September 7–9.

Dingrong, Zheng. "A Study of the World Bank Environmental Guidelines and an Appraisal of Coal Fired Plant in the People's Republic of China." Draft.

Dooley, B., and R. Viswanathan. No date. "Life Extension and Assessment of Fossil Power Plants." EPRI publication CS-5208. Palo Alto, California, United States.

Epperly, W. R., and J. E. Hoffman. 1989. "Control of Ammonia and Carbon Monoxide Emissions in SNCR Technologies." Paper presented at the AIChE Conference, August 20–23.

EPRI (Electric Power Research Institute). 1983. "Coal Gasification Systems: A Guide to Status, Applications, and Economics." EPRI publication AP-3109, June.

_____. 1985. "The Value of a Power Plant's Remaining Life: A Case Study with Baltimore Gas & Electric Co." EPRI publication EA-4347, November. Palo Alto, California, United States.

_____. 1986. "Generic Guidelines of Life Extension of Fossil Fuel Power Plants." EPRI publication CS-4778. Palo Alto, California, United States. November.

_____. 1993. *Proceedings of the SO_2 Control Symposium (Section 5A).* Boston, Massachusetts, August 24-27. Available from EPRI (also available from U.S. EPA and U.S. DOE). Palo Alto, California, United States.

_____. 1994. "Meeting the Particulate Control Challenge: State-of-the-Art Tools for Controlling Particulate Emissions from Fossil-Fired Power Plants."

_____. No date-a. "Economic Evaluation of Plant-upgrading Investments." Palo Alto, California, United States. EPRI publication EA-3890.

_____. No date-b. Strategy for Fossil Plant Life Extension at Boston Edison Co.'s Mystic Unit #6." EPRI publication CS-4779.

EPRI and EMENA (World Bank Europe, Middle East, and North Africa Vice-Presidency). 1989. *The Current State of Atmospheric Fluidized-Bed Combustion Technology.* World Bank Technical Paper 107. Washington, D. C.

Eskinazi, D. 1993. "Retrofit NO_x Controls for Coal-Fired Utility Boilers." EPRI publication TR-102071, Summer. Palo Alto, California, United States (licensed material).

European Community. 1988. *Council Directive* 88/609 of 24 November on the limitation of emission of certain pollutants into the air from large combustion plants, O.J. L 336/1. Published in the European Community Deskbook. 1992. The Environmental Law Institute, Washington D.C.

Exxon Research & Engineering. 1989. "Thermal DeNO_x Process." April.

Frank, N. W., and S. Hirano. 1988. "Combined NO_x/SO_2 Removal by Electron-Beam Processing." Paper presented at the 4th Symposium on Integrated Environmental Control, Cosponsored by EPRI, Air Pollution Association and the American Society of Mechanical Engineers. Washington, D.C., March 2–4.

Government of India. 1986. "Environment (Protection) Rules." Schedule I. In *Gazette of India: Extraordinary.*

Haslbeck, J. L., and others. 1993. "NO_xSO Combined NO_x/SO_2 Flue Gas Treatment Process—Proof of Concept." Paper presented at the SO_2 Control Symposium (Section 5A), Boston, Massachusetts, August 24-27. Available from EPRI, U.S. EPA, and U.S. DOE. Washington, D.C.

Her Majesty's Inspectorate of Pollution). 1991. *Chief Inspector's Guidance to Inspectors.* Environmental Protection Act 1990 Process Guidance Note IPR 1/1. Combustion Processes Large Boilers and Furnaces 50 MW(th) and Over. London: HMSO.

International Energy Agency. 1990. *NO_x Control Technologies for Coal Combustion.* International Energy Agency Coal Research, London.

_____. 1992. *Coal Information 1992.* International Energy Agency.

_____. 1993. *FGD Power Plants.* International Energy Agency Coal Research, London.

Japan Electric Power Information Center, Inc. 1992. *Thermal Power and Environmental Pollution Control in Japan.*

Jechoutek, Karl G., and others. 1992. *Steam Coal for Power and Industry: Issues and Scenarios.* Energy Series Paper 58. World Bank, Industry and Energy Department. World Bank, Washington D.C.

Kataoka, S. 1993. "Coal Burning Plant and Emission Control Technologies." Paper presented at the 2nd Annual Clean Coal Technology Conference, Atlanta, Georgia, September. 7–9.

Keen, R. T., and others. 1993. "Enhancing the Use of Coal by Gas Reburning and Sorbent Injection." Paper presented at the 2nd Annual Clean Coal Technology Conference, Atlanta, Georgia, September 7–9.

Makanski, Jason. 1990. "Will Combined SO_2/NO_x Processes Find a Niche in the Market?" *Power Magazine* (September): 26–28.

Miliaras, S. 1991. "Clean Coal Technologies for Developing Countries." Preliminary draft for United Nations Energy Resources Branch, September.

Moon, Hee Sung. 1993. "Integrating Coal Use into Korean Energy Systems." Paper presented at IEA Second International Conference on The Clean Efficient Use of Coal and Lignite: Its Role in Energy, Environment and Life. Bangkok, 30 November – 3 December.

Offen, G., and R. Altman. 1991. "Issues and Trends in Electrostatic Precipitation Technology for U.S. Utilities," *Journal of the Air and Waste Management Association* 42(2).

Philippines Department of Environment and Natural Resources. 1993. *Administrative Order.* No. 14. Manila.

Podolski, W. F., and others. No date. "PFBC Technology." Noyes Data Press.

RFF (Resources for the Future). 1992. *Handbook of Regulations on Environmental Protection in China.* Original Compiled in Chinese by the Beijing Municipal Environmental Protection Bureau.

Soud, Hermine N. 1991. *Emission Standards Handbook: Air Pollutant Standards for Coal-fired Plants.* IEACR/43 International Energy Agency Coal Research, London.

Tavoulareas, S. 1991. "Fluidized-Bed Combustion Technology." *Annual Review of Energy* (October): 25–27.

_____. 1993. "Clean Power Technology Menu for India." Report prepared for U.S.AID, August 27.

Williford, C. W. 1989. "Review of Coal Pretreatment Methods for Enhancement of Coal Liquefaction." EPRI preliminary draft paper, December 29.

Distributors of World Bank Publications

ARGENTINA
Carlos Hirsch, SRL
Galeria Guemes
Florida 165, 4th Floor-Ofc. 453/465
1333 Buenos Aires

Oficina del Libro Internacional
Alberti 40
1082 Buenos Aires

AUSTRALIA, PAPUA NEW GUINEA, FIJI, SOLOMON ISLANDS, VANUATU, AND WESTERN SAMOA
D.A. Information Services
648 Whitehorse Road
Mitcham 3132
Victoria

AUSTRIA
Gerold and Co.
Graben 31
A-1011 Wien

BANGLADESH
Micro Industries Development Assistance Society (MIDAS)
House 5, Road 16
Dhanmondi R/Area
Dhaka 1209

BELGIUM
Jean De Lannoy
Av. du Roi 202
1060 Brussels

BRAZIL
Publicacoes Tecnicas Internacionais Ltda.
Rua Peixoto Gomide, 209
01409 Sao Paulo, SP

CANADA
Le Diffuseur
151A Boul. de Mortagne
Boucherville, Québec
J4B 5E6

Renouf Publishing Co.
1294 Algoma Road
Ottawa, Ontario
K1B 3W8

CHINA
China Financial & Economic Publishing House
8, Da Fo Si Dong Jie
Beijing

COLOMBIA
Infoenlace Ltda.
Apartado Aereo 34270
Bogota D.E.

COTE D'IVOIRE
Centre d'Edition et de Diffusion Africaines (CEDA)
04 B.P. 541
Abidjan 04 Plateau

CYPRUS
Center of Applied Research
Cyprus College
6, Diogenes Street, Engomi
P.O. Box 2006
Nicosia

CZECH REPUBLIC
National Information Center
P.O. Box 668
CS-11357 Prague 1

DENMARK
SamfundsLitteratur
Rosenoerns Allé 11
DK-1970 Frederiksberg C

DOMINICAN REPUBLIC
Editora Taller, C. por A.
Restauración e Isabel la Católica 309
Apartado de Correos 2190 Z-1
Santo Domingo

EGYPT, ARAB REPUBLIC OF
Al Ahram
Al Galaa Street
Cairo

The Middle East Observer
41, Sherif Street
Cairo

FINLAND
Akateeminen Kirjakauppa
P.O. Box 128
SF-00101 Helsinki 10

FRANCE
World Bank Publications
66, avenue d'Iéna
75116 Paris

GERMANY
UNO-Verlag
Poppelsdorfer Allee 55
53115 Bonn

GHANA
Greenwich Mag. and Books
Rivera Beach Hotle
PO Box 01198
Osu-Accra

GREECE
Papasotiriou S.A.
35, Stournara Str.
106 82 Athens

HONG KONG, MACAO
Asia 2000 Ltd.
46-48 Wyndham Street
Winning Centre
7th Floor
Central Hong Kong

HUNGARY
Foundation for Market Economy
Dombovari Ut 17-19
H-1117 Budapest

INDIA
Allied Publishers Ltd.
751 Mount Road
Madras - 600 002

INDONESIA
Pt. Indira Limited
Jalan Borobudur 20
P.O. Box 1181
Jakarta 10320

IRAN
Kowkab Publishers
P.O. Box 19575-511
Tehran

IRELAND
Government Supplies Agency
4-5 Harcourt Road
Dublin 2

ISRAEL
Yozmot Literature Ltd.
P.O. Box 56055
Tel Aviv 61560

R.O.Y. International
P.O.B. 13056
Tel Aviv 61130

Palestinian Authority/Middle East
P.O. Box 19502, Jerusalem

ITALY
Licosa Commissionaria Sansoni SPA
Via Duca Di Calabria, 1/1
Casella Postale 552
50125 Firenze

JAMAICA
Ian Randle Publishers Ltd.
206 Old Hope Road
Kingston 6

JAPAN
Eastern Book Service
Hongo 3-Chome, Bunkyo-ku 113
Tokyo

KENYA
Africa Book Service (E.A.) Ltd.
Quaran House, Mfangano Street
P.O. Box 45245
Nairobi

KOREA, REPUBLIC OF
Pan Korea Book Corporation
P.O. Box 101, Kwangwhamun
Seoul

Daejon Trading Co. Ltd.
P.O. Box 34, Youido
Seoul

MALAYSIA
University of Malaya Cooperative Bookshop, Limited
P.O. Box 1127, Jalan Pantai Baru
59700 Kuala Lumpur

MEXICO
INFOTEC
Apartado Postal 22-860
14060 Tlalpan, Mexico D.F.

NETHERLANDS
De Lindeboom/InOr-Publikaties
P.O. Box 202
7480 AE Haaksbergen

NEW ZEALAND
EBSCO NZ Ltd.
Private Mail Bag 99914
New Market
Auckland

NIGERIA
University Press Limited
Three Crowns Building Jericho
Private Mail Bag 5095
Ibadan

NORWAY
Narvesen Information Center
Book Department
P.O. Box 6125 Etterstad
N-0602 Oslo 6

PAKISTAN
Mirza Book Agency
65, Shahrah-e-Quaid-e-Azam
P.O. Box No. 729
Lahore 54000

Oxford University Press
P.O. Box 13033
Karachi - 75350

PERU
Editorial Desarrollo SA
Apartado 3824
Lima 1

PHILIPPINES
International Book Center
Suite 1703, Cityland 10
Condominium Tower 1
Ayala Avenue, H.V. dela Costa Extension
Makati, Metro Manila

POLAND
International Publishing Service
Ul. Piekna 31/37
00-677 Warszawa

PORTUGAL
Livraria Portugal
Rua Do Carmo 70-74
1200 Lisbon

SAUDI ARABIA, QATAR
Jarir Book Store
P.O. Box 3196
Riyadh 11471

SLOVAK REPUBLIC
Slovart G.T.G Ltd.
Krupinska 4
P.O. Box 152
852 99 Bratislava 5

SINGAPORE, TAIWAN, MYANMAR, BRUNEI
Gower Asia Pacific Pte Ltd.
Golden Wheel Building
41, Kallang Pudding, #04-03
Singapore 1334

SOUTH AFRICA, BOTSWANA
For single titles:
Oxford University Press Southern Africa
P.O. Box 1141
Cape Town 8000

For subscription orders:
International Subscription Service
P.O. Box 41095
Craighall
Johannesburg 2024

SPAIN
Mundi-Prensa Libros, S.A.
Castello 37
28001 Madrid

Libreria Internacional AEDOS
Consell de Cent, 391
08009 Barcelona

SRI LANKA AND THE MALDIVES
Lake House Bookshop
P.O. Box 244
100, Sir Chittampalam A. Gardiner Mawatha
Colombo 2

SWEDEN
Fritzes Customer Service
S-106 47 Stockholm

Wennergren-Williams AB
P. O. Box 1305
S-171 25 Solna

SWITZERLAND
Librairie Payot
Case postale 3212
CH 1002 Lausanne

Van Dierman Editions Techniques - ADECO
P.O. Box 465
CH 1211 Geneva 16

TANZANIA
Oxford University Press
Maktaba Street
P.O. Box 5299
Dar es Salaam

THAILAND
Central Department Store
306 Silom Road
Bangkok

TRINIDAD & TOBAGO
Systematics Studies Unit
#9 Watts Street
Curepe
Trinidad, West Indies

UGANDA
Gustro Ltd.
1st Floor, Room 4, Geogiadis Chambers
P.O. Box 9997
Plot (69) Kampala

UNITED KINGDOM
Microinfo Ltd.
P.O. Box 3
Alton, Hampshire GU34 2PG
England

ZAMBIA
University of Zambia Bookshop
Great East Road Campus
P.O. Box 32379
Lusaka

ZIMBABWE
Longman Zimbabwe (Pvt.) Ltd.
Tourle Road, Ardbennie
P.O. Box ST 125
Southerton
Harare

RECENT WORLD BANK TECHNICAL PAPERS *(continued)*

No. 243 Menke and Fazzari, *Improving Electric Power Utility Efficiency: Issues and Recommendations*

No. 244 Liebenthal, Mathur, and Wade, *Solar Energy: Lessons from the Pacific Island Experience*

No. 245 Klein, *External Debt Management: An Introduction*

No. 246 Plusquellec, Burt, and Wolter, *Modern Water Control in Irrigation: Concepts, Issues, and Applications*

No. 247 Ameur, *Agricultural Extension: A Step beyond the Next Step*

No. 248 Malhotra, Koenig, and Sinsukprasert, *A Survey of Asia's Energy Prices*

No. 249 Le Moigne, Easter, Ochs, and Giltner, *Water Policy and Water Markets: Selected Papers and Proceedings from the World Bank's Annual Irrigation and Drainage Seminar, Annapolis, Maryland, December 8-10, 1992*

No. 250 Rangeley, Thiam, Andersen, and Lyle, *International River Basin Organizations in Sub-Saharan Africa*

No. 251 Sharma, Rietbergen, Heimo, and Patel, *A Strategy for the Forest Sector in Sub-Saharan Africa*

No. 252 The World Bank/FAO/UNIDO/Industry Fertilizer Working Group, *World and Regional Supply and Demand Balances for Nitrogen, Phosphate, and Potash, 1992/93–1998/99*

No. 253 Jensen and Malter, *Protected Agriculture: A Global Review*

No. 254 Frischtak, *Governance Capacity and Economic Reform in Developing Countries*

No. 255 Mohan, editor, *Bibliography of Publications: Technical Department, Africa Region, July 1987 to April 1994*

No. 256 Campbell, *Design and Operation of Smallholder Irrigation in South Asia*

No. 257 Malhotra, Sinsukprasert, and Eglington, *The Performance of Asia's Energy Sector*

No. 258 De Geyndt, *Managing the Quality of Health Care in Developing Countries*

No. 259 Chaudry, Reid, and Malik, editors, *Civil Service Reform in Latin America and the Caribbean: Proceedings of a Conference*

No. 260 Humphrey, *Payment Systems: Principles, Practice, and Improvements*

No. 261 Lynch, *Provision for Children with Special Educational Needs in the Asia Region*

No. 262 Lee and Bobadilla, *Health Statistics for the Americas*

No. 263 Le Moigne, Giltner, Subramanian, and Xie, editors, *A Guide to the Formulation of Water Resources Strategy*

No. 264 Miller and Jones, *Organic and Compost-Based Growing Media for Tree Seedling Nurseries*

No. 265 Viswaneth, *Building Partnerships for Poverty ReductionThe Participatory Project Planning Approach of the Women's Enterprise Management Training Outreach Program* (WEMTOP)

No. 266 Hill and Bender, *Developing the Regulatory Environment for Competitive Agricultural Markets*

No. 267 Valdés and Schaeffer, *Surveillance of Agricultural Prices and Trade: A Handbook for the Dominican Republic*

No. 268 Valdés and Schaeffer, *Surveillance of Agricultural Prices and Trade: A Handbook for Colombia*

No. 269 Scheierling, *Overcoming Agricultural Pollution of Water: The Challenge of Integrating Agricultural and Environmental Policies in the European Union*

No. 270 Banerjee, *Rehabilitation of Degraded Forests in Asia*

No. 271 Ahmed, *Technological Development and Pollution Abatement: A Study of How Enterprises Are Finding Alternatives to Chlorofluorocarbons*

No. 273 Grimshaw and Helfer, editors, *Vetiver Grass for Soil and Water Conservation, Land Rehabilitation, and Embankment Stabilization: A Collection of Papers and Newsletters Compiled by the Vetiver network*

No. 274 Govindaraj, Murray, and Chellaraj, *Health Expenditures in Latin America*

No. 275 Heggie, *Management and Financing of Roads: An Agenda for Reform*

No. 276 Johnson, *Quality Review Schemes for Auditors: Their Potential for Sub-Saharan Africa*

No. 277 Convery, *Applying Environmental Economics in Africa*

No. 278 Wijetilleke and Karunaratne, *Air Quality Management: Considerations for Developing Countries*

No. 279 Anderson and Ahmed, *The Case for Solar Energy Investments*

THE WORLD BANK
A partner in strengthening economies
and expanding markets
to improve the quality of life
for people everywhere,
especially the poorest

Headquarters
1818 H Street, N.W.
Washington, D.C. 20433, U.S.A.

Telephone: (202) 477-1234
Facsimile: (202) 477-6391
Telex: MCI 64145 WORLDBANK
MCI 248423 WORLDBANK
Cable Address: INTBAFRAD
WASHINGTONDC

European Office
66, avenue d'Iéna
75116 Paris, France

Telephone: (1) 40.69.30.00
Facsimile: (1) 40.69.30.66
Telex: 640651

Tokyo Office
Kokusai Building
1-1, Marunouchi 3-chome
Chiyoda-ku, Tokyo 100, Japan

Telephone: (3) 3214-5001
Facsimile: (3) 3214-3657
Telex: 26838

13308
9 780821 333082
ISBN 0-8213-3308-9