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Advanced Power Assessment for Czech Lignite
Task 3.6, Volume I

Topical Report

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ABB CE	ABB Combustion Engineering
ACAA	American Coal Ash Association
AFBC	atmospheric fluidized-bed combustion
AMP	ammoniated polycarboxylic acid
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BATNERC	best available technology not exceeding reasonable cost
B&W	Babcock & Wilcox
BGL	British Gas/Lurgi
CC	combustion controls
CCT	Clean Coal Technology
CEZ	Czech Power Works Company
CFB	circulating fluidized bed
CFBC	circulating fluidized-bed combustion
CHP	combined heat and power facility (cogeneration facility)
COHPAC	Compact Hybrid Particulate Collector
$\mathrm{CombiNO_x}$	process to control SO_2 and NO_x
CRIP	controlled retracting injection point
CWF	coal–water fuel
daf	dry, ash-free
db	dry basis
DBA	dibasic acid
DCF	discounted cash flow
DMEC	Des Moines Energy Center
DOE	Department of Energy
DSC	differential scanning calorimetry
EER	Energy and Environmental Research Corporation
EERC	Energy & Environmental Research Center
EIA	Energy Information Agency
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
EU	European Union
FGD	flue gas desulfurization
FGR	flue gas recirculation
FT-IR	Fourier transform infrared analysis
FWEC	Foster Wheeler Energy Corporation
GDP	gross domestic product
GE	General Electric
GJ	gegajoule
HHV	higher heating value
HRSG	heat recovery steam generator
HTW	high-temperature Winkler
hvA	high volatile A
ID	induced draft

IEA	International Energy Agency, an agency within the OECD
IGCC	integrated gasification combined cycle
IGT	Institute of Gas Technology
IMF	International Monetary Fund
IPP	independent power producers
KRW	Kellogg Rust Westinghouse
kW	kilowatt
LFC	liquids from coal
L/G	liquid-to-gas ratio
LHV	lower heating value
LIDS	limestone injection dry scrubbing
LNB	low-NO_x burners
LNCFS	low-NO_x concentric firing system
LOI	loss on ignition
LP	low pressure
LRC	low-rank coal, includes subbituminous or brown coal and lignite
LRCWF	low-rank coal–water fuel
LSFO	limestone forced-oxidation
MACT	maximum achievable control technology
maf	moisture- and ash-free
MBG	medium-Btu gas
METC	Morgantown Energy Technology Center
mg	milligram
MIBRAG	Mitteldeutsche Braunkohlengesellschaft mbH
MJ	megajoule
MMBtu	million Btu
MSW	municipal solid waste
MTBE	methyl *tertiary*-butyl ether
MW	megawatt
MW_e	megawatt electrical
MW_{th}	megawatt thermal
NGR	natural gas reburning
nm	nanometer
Nm^3	normal cubic meter
NMR	nuclear magnetic resonance spectroscopy
NOXSO	process to control NO_x and SO_2 simultaneously
NSPS	New Source Performance Standards
O&M	operations and maintenance
OECD	Organization for Economic Cooperation and Development
OFA	overfire air
PETC	Pittsburgh Energy Technology Center
PFBC	pressurized fluidized-bed combustion
PJFF	pulse-jet fabric filter
REMS	rare earth magnetic separation
SCA	specific collection area
SCR	selective catalytic reduction
SDA	spray dryer absorbers
SNCR	selective noncatalytic reduction

SNG	synthetic natural gas
SNOX	combined SO_2 and NO_x control technology
TAMCO	Tampella Corporation (Finland)
TCC	turbine combustion control
UCG	underground coal gasification
UCPTE	West European Power Grid
TVA	Tennessee Valley Authority
USSR	Union of Soviet Socialist Republics
VOC	volatile organic carbons
W.C.	water column
WLS	wet limestone scrubbers
wt	weight
WTE	waste-to-energy
XRF	x-ray fluorescence
ZVU	Závody Vítězného Úmora

ADVANCED POWER ASSESSMENT FOR CZECH LIGNITE

EXECUTIVE SUMMARY

PERSPECTIVE ON THE CZECH ENERGY ECONOMY

Major reforms in the Czech energy sector have been initiated to reverse 40 years of central planning, subsidized energy pricing, unchecked pollution from coal-fired plants, concerns over nuclear safety and fuel cycle management, and dependence on the former U.S.S.R. for oil, gas, and nuclear fuel processing. Prices for electricity, heat, and natural gas paid by industry are close to western levels, but subsidized prices for households are as much as 40% lower and below economic cost. State control of major energy enterprises is being reduced by moving toward government-regulated, investor-owned companies to raise needed capital, but with a strategic stake retained by the state. Foreign firms will participate in privatization, but they are not expected to acquire a controlling interest in Czech energy companies.

Economic conditions in the Czech Republic are now improving after the disruptions caused by restructuring since 1989 and separation of the former Czech and Slovak Federal Republics in January 1993. The downturn in the economy after 1989 was concentrated in energy-intensive heavy industry, and recovery is paced by consumer trade, services, light industry and construction. Energy use in relation to gross domestic product (GDP) has declined, but it is still significantly higher than in OECD (Organization for Economic Cooperation and Development) countries. The GDP increased by 2% in 1994 after dropping 22% between 1989 and 1993. A positive balance of payments has been achieved, with foreign investment offsetting a small trade deficit. The government's external debt is only 4% of GDP.

Sources of primary energy in 1993 included 53% from lignite, 11.5% from hard coal, 14.5% from oil, 13% from gas, 7.5% from nuclear and 0.5% from hydroelectric power. One-third of the primary energy is imported, including most of the oil and gas. Demand for natural gas is projected to grow 6%–7% annually to the year 2005, with diversification of supply to reduce concentrated dependence on Russia. Nuclear energy will be expanded by the completion of two 1000-MW reactors after 1998. The only major domestic energy resources are lignite reserves of 2340 million tons and hard coal reserves of 980 million tons, sufficient for 30 and 50 years, respectively, at current use rates. Lignite production declined by 23% and hard coal by 27% between 1989 and 1993, and a further decline of up to one-third is projected by 2005 for economic and environmental reasons. Lignite which is priced at about US$1/GJ is competitive in many applications with natural gas at about US$3/GJ. Hard steam coal priced at about US$1.50/GJ faces strong competition from foreign coal supplies and imported natural gas. New uses for lignite that are both economic and environmentally acceptable would greatly benefit the national economy and promote the welfare of displaced miners. The quality of lignite varies widely, from 0.4% to 6% sulfur and 7% to 44% ash on a dry basis.

Current markets for lignite in the Czech Republic are diversified, including 55% going to electric power generation and smaller percentages to district heating plants, industrial plants, institutions, and households. The total electric generating capacity of 14,285 MW (1993) is comprised 77.6% by coal-fired units, 12.3% by nuclear, 9.6% by hydroelectric, and 0.5% by other sources. The Czech Power Works Company (CEZ) accounts for 72% of electrical generation. The decline in demand for electricity after 1989 appears to have come to an end, and an annual growth rate of 1.6% is projected to the year 2000. A reported 30% reserve capacity margin includes older combined heat and power (CHP) plants that generate little electricity. District heat and CHP plants in 1992 were fueled 67% on coal, 21% on gas, and 12% on oil. Smaller CHP plants are being converted to natural gas, and some larger coal-fired units are being equipped with pollution controls.

Serious air pollution affecting the health of 20% of the population is concentrated in the lignite-burning region in Northern Bohemia and Upper Silesia, near coking plants in Ostrava, and in urban areas where coal is used for heating. Environmental legislation passed in 1989 and 1992 reversed the past practice of dispersing major sources of pollution by using tall stacks and instead established source emissions standards and implementation guidelines based on "best available technology not exceeding reasonable cost" (BATNERC). Emission standards for large, new coal combustion sources (100 mg/m^3 particulate, 500 mg/m^3 SO_2, and 650 mg/m^3 NO_x) are close to European Union (EU) levels.

A least-cost power study performed for CEZ showed that its existing coal-fired units could be rehabilitated and upgraded with emission controls at less than half the cost of new capacity—including natural gas-fired combined cycle, pulverized coal-fired steam plant, lignite-fired integrated gasification combined cycle (IGCC), or nuclear. The CEZ has initiated a development program to bring all of the coal-fired units that will remain in operation after commissioning of new nuclear capacity into compliance with Czech Clean Air Standards by the end of 1998. Future needs for new or repowered CHP cogeneration plants in the Czech Republic may represent the best opportunity for advanced IGCC and pressurized fluidized-bed combustion (PFBC) technologies.

REPOWERING AGING POWER SYSTEMS

The repowering of an old but still serviceable steam cycle can extend service life, increase generating capacity, improve efficiency, and control emissions. The two main classes of technologies for repowering coal-fired units are 1) atmospheric fluidized-bed combustion (AFBC) used to generate steam for the original steam turbine and 2) gas turbine combined-cycle systems reusing part or all of the original steam cycle and variously configured to include a) a natural gas-fired turbine integrated with the coal-fired steam cycle, b) an IGCC system, or c) a PFBC/combined cycle (CC) system. The cost of repowering is reduced by reusing as much of the original steam cycle as possible; however, the need for design flexibility in matching components may limit this reuse.

AFBC repowering is a direct alternative to retrofitting flue gas desulfurization (FGD) and NO_x control systems on older boilers. SO_2 emissions can be controlled by 90% at a limestone-to-sulfur molar ratio typically below 3 and by 70% at a ratio below 2. NO_x emissions from AFBC are naturally low because of the low combustion temperature

(1450°-1700°F or 788°-927°C): typically below 0.3 lb/MMBtu (approximately 400 mg/m^3 for lignite firing at 6% oxygen in flue gas). These emission control capabilities meet the Czech emission standards for new power systems. An AFBC repowering project can involve either a bubbling bed with a superficial gas velocity below about 2 m/sec or a circulating fluidized-bed combustor (CFBC) with a velocity of about 6 m/sec, depending on the design of the old boiler and the objectives of the project. A bubbling bed AFBC design can typically be installed at lower cost by using a larger part of the old boiler. In the United States, both an 80-MW spreader stoker and a 125-MW pulverized coal-fired boiler have been modified for bubbling bed AFBC operation at a substantial saving over a new boiler. The alternative CFBC design offers a carbon burnout approaching 100% and a higher sulfur capture at lower limestone use rates, which are important advantages for high-sulfur Czech lignites.

Large gas turbines available in sizes up to 220 MW can be integrated into coal-fired combined-cycle repowering systems by recovering heat from the gas turbine exhaust in either 1) a heat recovery steam generator (HRSG), 2) a feedwater preheater, or 3) a coal-fired steam generator (the hot wind-box design). Under these options, a 150-MW gas turbine can be used in systems ranging in size from about 225 to 600 MW. Supplemental firing with natural gas can be used to increase the efficiency and operating flexibility of repowered systems. The discrete size limitation of gas turbines can be variously compensated for by supplementary firing of the HRSG, by injecting excess steam into the gas turbine, or by cooling the air to the turbine to augment its power rating. Excess steam can also be used in steam turbine drives on boiler feed pumps, fans, and other auxiliaries. High generating efficiency can best be maintained at partial load by operating the gas turbine at nearly full load and the steam turbine at partial load. An overall load reduction down to 35% of rating is practical with the gas turbine operating at not less than 50%. Indirect firing of the gas turbine on coal is technically feasible using either IGCC or PFBC/CC technologies, which are covered in this report under advanced power systems. Combined-cycle repowering is particularly feasible for CHP cogeneration facilities in the Czech Republic, as already implemented at the Vresova IGCC plant that is scheduled to commence operation in January 1996.

EMISSIONS CONTROL

Plans for controlling emissions from coal-fired power stations in the Czech Republic call for decommissioning 2300 MW of obsolete lignite-fired generating capacity and upgrading 6200 MW of newer coal- and lignite-fired capacity to meet emission standards by 1998. Information is presented in this report on U.S. systems for control of particulates, sulfur dioxide, and nitrogen oxides, based in part on technical data obtained from vendors for an EERC study performed for the Bulgarian lignite industry (EERC, 1995). The U.S. companies expressing interest in emission control projects in East Central Europe in the Bulgarian study are identified in this report.

A large number of technology options have demonstrated capabilities for controlling emissions from various boiler types burning different quality coals around the world, including electrostatic precipitators (ESPs), fabric filters, spray dryer absorbers (SDAs), wet limestone scrubbers (WLS), overfire air staging (OFA), low-NO_x burners (LNB), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). Based on U.S. experience, both ESPs and fabric filters are appropriate technology options for meeting Czech particulate emissions limit; SDA and WLS are appropriate technology options for meeting SO_2 emission limits; and OFA and LNB should be appropriate technology options for meeting NO_x emission limits. Successful retrofitting to meet emission limits for the least cost requires that these technologies be evaluated in combination with other changes in fuel supply and plant equipment. Plans for fuel switching and boiler rehabilitation should be factored into the emission control evaluation process on existing units. For new units, subject to stricter emission limits, the selection of emission control equipment should be factored into the bid process from the viewpoint of overall economics, performance, and reliability.

Particulate Control

ESP technology is extensively used in Czech coal-fired power stations to control particulate emissions, and several ESP upgrades are available to meet higher levels of particulate control if required. Recommended ESP upgrades include the replacement of ESP internals using U.S.-designed plates and electrodes, an increase in collection area with greater sectionalization, the installation of new flue gas flow control devices to improve gas distribution, and the installation of new transformers, rapping systems, and controls. In some cases, existing ESPs can be upgraded for about half the cost of installing new ESPs. Some rehabilitation projects completed in East Central Europe have added 30%-40% more collection area into the existing casing without changing the plan area or ID fan by reducing the spacing between fields and increasing the height of the ESP but allowing for the reuse of existing support steel, ash hoppers, and handling system. Flue gas conditioning is also recommended as a low-cost option for improving ESP performance for stations considering low-sulfur coal options. In cases where ESP upgrades alone are not adequate to meet emission control requirements, an economical alternative would involve adding a high-face-velocity pulse-jet baghouse downstream of the ESP using the compact hybrid particulate collector (COHPAC) concept.

Fabric filters are the preferred particulate control technology on new U.S. boilers burning low-sulfur coals and generating high-resistivity fly ash that is difficult to collect in an ESP. Also, a fabric filter operating on a flue gas slipstream can be a cost-effective upgrade for an older boiler burning low-sulfur coal. Limitations on the use of fabric filters are primarily concerned with their larger space requirement and their potential for poor performance on certain problematic ashes. Solutions to problems with collection efficiency and pressure drop involve either chemical conditioning, particle agglomeration, or electrostatic enhancement.

Sulfur Dioxide Control

Plans reported by Czech sources in 1994 for the control of SO_2 emissions from coal-fired power stations called for repowering as many as nine units with AFBC (705 MW) and retrofitting FGD on thirty-one units (5740 MW). Projects for retrofitting WLSs on 3690 MW and SDAs on 220 MW had been committed up to that time, with start-up dates scheduled between 1994 and 1997. The selection of suppliers for the remaining FGD installations was reported as ongoing.

Because of the high sulfur content in the lignites used in many Czech power stations, WLSs are generally the most cost-effective choice for larger units (>200 MW) having a remaining operating life greater than 15 years and for those units requiring high removal efficiencies up to 95%. An SDA or a circulating fluidized-bed scrubber may be appropriate for some smaller power-generating units (50 to 200 MW) and CHP cogeneration units requiring 70% to 90% SO_2 control. Low-capital-cost retrofit technologies, such as furnace sorbent injection or duct injection, are not appropriate options even as short-term mitigation measures where limited financial resources must be focused to meet high levels of SO_2 control. Available financial resources should instead be invested in higher removal efficiency options that meet long-term objectives and minimize the cost of SO_2 control on a $/ton and levelized-cost basis. At the policy level, an emissions trading system such as was implemented in the United States in 1990 can be used to further minimize the overall cost of compliance on a systemwide basis.

Information on a number of advanced FGD technologies is summarized in this report. The majority of new systems currently being installed in the United States are limestone forced-oxidation (LSFO) units, for which the reported cost of retrofit installations average US$231/kW with a range of US$120 to US$348/kW. The use of organic acid additives in WLSs has been shown to increase SO_2 removals from 85%–90% to 95%–98% for existing scrubbers. SDA installations in the United States have been limited to units burning low-sulfur subbituminous coals and lignites, but pilot-scale tests on improved SDA systems performed by several organizations, including the Electric Power Research Institute (EPRI) and the Babcock & Wilcox Company, have demonstrated SO_2 removals of 95% for higher-sulfur coals. Other recently reported U.S. developments for achieving high SO_2 removal at lower cost include a condensing heat exchanger by Babcock & Wilcox, a clear liquor limestone scrubber by EPRI, an ammonia-based scrubber by GE Environmental Services, Inc., a magnesium-enhanced lime scrubber by Dravo Lime Company, and an advanced wet FGD high-velocity spray tower by ABB Environmental Systems. The U.S. Department of Energy (DOE) Clean Coal Demonstration Program has sponsored additional projects at utility scale demonstrating high-efficiency SO_2 control technologies that may offer advantages for Czech power stations, including the low-cost, single-module WLS by Pure Air, the combined SO_2–NO_x SNOX project by ABB Environmental Systems, and a number of others. Overall, a very wide range of SO_2 control technologies are available that are appropriate to the Czech power industry. A technical evaluation is needed for each retrofit unit and fuel to select the optimum technology for achieving the highest possible SO_2 removal and reliability and the lowest cost.

NO_x Control

Measures for controlling NO_x emissions are not yet being used on coal-fired boilers in the Czech Republic, based on available information. Five general classes of NO_x control technology can be used to achieve progressively higher levels of control at correspondingly higher cost: 1) Combustion controls including LNB and OFA achieve levels of 410–820 mg/Nm^3 at a capital cost of US$13–US$25/kW. 2) Natural gas reburning (NGR) achieves 340–615 mg/Nm^3 at US$21–US$34/kW. 3) Pulverized coal reburn (PCR) using subbituminous coal achieved 340–465 mg/Nm^3 in a demonstration test at a capital cost of US$66/kW. 4) Selective noncatalytic reduction injecting aqueous urea or ammonia in a carefully controlled temperature range achieves 410–680 mg/Nm^3 at a low capital cost of US$8–US$22/kW, but at a significant operating cost of US$500–US$1000/ton of NO_x removed. 5) Selective catalytic reduction achieves 150–250 mg/Nm^3 at a capital cost of US$60–US$100/kW and a levelized operating cost of about US$1000/ton of NO_x removed.

Based on U.S. experience, combustion controls using OFA, LNB, and fine tuning of the boiler should be appropriate technology for meeting the Czech Republic NO_x emission limit of 650 mg/Nm^3. However, since test data indicate significant variations in control levels for all methods of NO_x control depending on coal rank, boiler design, and operating conditions, a careful technical evaluation is needed to select the most appropriate design for each different generating unit and fuel. Combustion controls and reburning methods in general achieve lower NO_x emissions on pulvlerized coal-fired boilers for high-moisture low-rank coals than for bituminous coal, and emission levels well below the 650-mg/Nm^3 limit should be achievable for Czech lignites. OFA and LNB methods are not applicable to cyclone-fired boilers, and reburn methods would be the preferred approach for achieving the required control level. Potential problems that need to be considered in connection with NO_x combustion controls include possible slagging and fouling in the boiler, tube or waterwall wastage, increased levels of CO and unburned carbon, and steam temperature control. A summary of control performance for each of the above classes of control technology is given in this report along with vendor identification.

Integrated Emission Control Systems

A number of integrated concepts for controlling emissions (SO_2, NO_x, and/or particulate) from coal-fired systems are at various stages of evaluation and/or demonstration. The DOE Clean Coal Technology Demonstration Program is supporting several integrated concepts for simultaneous emission control: the NOXSO process, the Copper Oxide Process, the ABB Environmental Systems SNOX process, and the Babcock & Wilcox (B&W) "SO_x–NO_x–RO_x Box."

Although integrated emission control systems show promise for future commercial applications, their high capital costs and lack of commercial experience make them poor choices at this time for meeting the near-term requirements of the Czech power industry. However, new coal-fired power stations constructed in the next century are expected to make use of these more efficient integrated emission control technologies to produce salable by-products rather than waste products requiring disposal.

ADVANCED POWER SYSTEMS

Emerging power systems, including advanced CFBC, PFBC, and IGCC being demonstrated under the DOE Clean Coal Technology Program present opportunities for achieving generating efficiencies of 50% or higher with stringent control of SO_2, NO_x, and particulate emissions. At their present stage of development and demonstration, these coal-fired technologies offer superior environmental performance for repowering, cogeneration, and greenfield projects at costs that are close to comparable to pulverized fuel firing with full stack gas cleaning, but at considerably higher technical and financial risk. This assessment identifies certain technologies as being most suitable for lignites containing high levels of moisture, ash, and sulfur. However, the optimum design choices for low-quality lignite will change as progress is made in developing more advanced gas turbines, hot-gas cleaning methods, and other technology improvements. Considering the present adequacy of the installed electrical generating capacity in the Czech Republic, the time horizon for a baseload lignite-fired advanced power system will likely be delayed until these technical improvements have been fully developed and demonstrated to present an acceptable level of risk. However, repowering of CHP cogeneration facilities is a near-term opportunity for advanced power technologies as previously discussed.

The following advanced technologies can be identified as offering advantages for future cogeneration applications fueled on Czech lignite:

- CFBC offers the lowest risk and greatest flexibility for burning low-quality, high-ash, high-sulfur lignite with good turndown capability, high levels of sulfur and NO_x control, and high sorbent utilization.

- A PFBC/CC system operating on lignite is predicted to generate more than half of its power in the gas turbine, owing to the low level of in-bed heat transfer and high mass flow associated with high moisture. A simple and relatively low-cost PFBC system could be designed to generate limited amounts of power from high-moisture lignite using only a gas turbine without the steam turbine, making all of the steam production available for district heating or other thermal applications. Interest in this approach depends on the relative power and steam load requirements and the economics of the simplified system.

- The MW Kellogg Company developed a transport reactor (a pressurized, circulating, fast fluidized bed capable of operating in both combustion and gasification modes) that it recommends for firing a gas turbine on lignite, with supplementary firing on natural gas. Supplemental firing would raise the turbine inlet temperature and provide a high incremental efficiency for the natural gas burned. Also, within somewhat narrow limits, the division of energy flow between power generation and steam for heating could be adjusted by tempering with additional moisture in the transport combustor. The combination of tempering and supplemental firing represents a possibility for designing a system that would offer some flexibility to respond to both surge needs for electrical generation and changes in demand for steam.

- Underground coal gasification (UCG) has the potential for utilizing deep and otherwise uneconomic lignite deposits in the Czech Republic for power generation. The use of UCG for supplying fuel gas for a combined-cycle power system is estimated to offer a 10% to 20% savings in capital cost, plus lower operating costs, compared to a surface gasification system. UCG in the United States has advanced to near-commercial readiness as a result of tests performed between 1975 and 1987, based primarily on subbituminous coal and lignite. Methods have been developed for minimizing groundwater contamination at suitable sites. A careful evaluation of the geology and hydrogeology of the candidate site is an important requirement for a UCG project.

- The installation of a natural gas-fired combined-cycle system, suitable for later conversion to IGCC, raises important design and cost questions that need to be considered when initially selecting the gas turbine; these concerns are summarized in the text of this report. A preliminary choice of gasifier and related gas-cleaning equipment should be made at the time the gas turbine is selected to ensure compatibility.

The choice of a gasifier design for a lignite-fired cogeneration facility depends on the lignite properties and the planned timing of the IGCC project, assuming that hot-gas cleaning methods will be perfected for later conversion scenarios. Computed heat and material balances are presented in the report for fixed-bed, fluidized-bed, and entrained-flow type gasifiers to illustrate their operating characteristics in relation to the moisture, ash, and sulfur contents of the fuel. For a near-term lignite-fired IGCC, an oxygen-blown, dry-feed, high-temperature gasifier, such as the Shell entrained-flow unit coupled with cold-gas cleaning, would provide assurance of meeting all requirements, including feeding the lignite, achieving high carbon conversions, providing stringent sulfur control, producing a benign disposable waste (slag), and providing a very clean medium-Btu gas (MBG) fully suitable for gas turbine combustion. Slurry feed gasifiers such as the Destec or Texaco designs are recommended for high-moisture, high-ash lignites only if coal moisture has first been irreversibly reduced by drying at moderately high temperatures (240°–300°C) in steam or hot water. With future development, it may be possible to modify slurry feed systems to integrate a continuous and simplified hot-water-drying step at an acceptable cost. Alternatively, dry-feed systems based on fluidized-bed gasifiers such as the Tampella/Institute of Gas Technology (IGT), Kellogg Rust Westinghouse (KRW), or high-temperature Winkler (HTW) units or on a Lurgi-type fixed-bed gasifier can also be used with cold-gas cleaning, subject to certain fuel property requirements presented in the report.

For lignite-fired IGCC projects planned after 2000, air-blown gasifiers with hot-gas cleaning can be used to reduce cost and improve efficiency, most probably using either a fluidized-bed or a fixed-bed gasifier along with hot-gas cleaning modules for tar cracking (for fixed-bed gasifiers), in-bed and/or mixed-metal oxide sulfur control, alkali vapor capture, and porous ceramic particulate filtration to provide moderately clean fuel gas. However, hot-gas cleaning will introduce certain new design and operating problems, such as when in-bed sulfur capture requires an auxiliary combustion unit to convert calcium sulfide to a disposable sulfate waste and when mixed-metal oxide or cracking catalysts require regeneration.

PFBC with hot-gas particulate filtration can also be used along with auxiliary firing on either natural gas or coal carbonization gas, as developed by Foster Wheeler Energy Corporation (FWEC), to provide similarly high efficiency and emission control and potential cost savings.

UPGRADING TECHNOLOGIES AND ALTERNATIVE MARKETS FOR LIGNITE

Traditional markets for lignite in the Czech Republic are declining with the decommissioning of older coal-fired power plants and conversion of some district heating plants to natural gas, making the development of alternative uses for lignite an important goal for the national economy and the welfare of displaced miners. Various upgrading technologies are available that are applicable to the distinctive properties of lignite, which include a diverse molecular structure, an abundance of oxygen functional groups, high moisture content, highly variable sulfur content, high reactivity, and a wide range of associated mineral grains and exchangeable ions on active sites on the coal. An important criterion for a successful upgrading process is that it provides a substantial added value to pay for the cost of processing, which focuses attention on limited-tonnage high-value fuel products such as smokeless briquettes for space heating or on nonfuel products such as activated carbon more than on high-tonnage upgraded boiler fuels.

Coal Cleaning

Cleaning steam coals for use by electric utilities offers a number of economic benefits derived from reduced transportation and handling costs, reduced boiler tube erosion, mill wear, ash slagging and fouling, and increased pulverizer capacity, all of which may be important for Czech lignites. Cleaning for sulfur control is a primary objective only where the source emission limit can be met by gravity cleaning alone without installing a scrubber, which may not apply in the Czech Republic. However, the greatest benefit from cleaning Czech lignites would probably be gained where ash or sulfur reduction can be integrated as a step toward producing higher-value products.

The cleaning methods that are technically and economically most applicable to low-rank coals are gravity cleaning in heavy media and fine-coal cleaning by oil agglomeration using a polar oil that will adhere to the hydrophilic lignite surface. Various chemical cleaning methods including acid washing, aqueous caustic oxidation, and molten caustic leaching that can reduce ash and/or sulfur to very low levels are technically feasible but are too costly for most applications (e.g., US$0.60 to US$2/GJ in added fuel cost). Gravity-cleaning tests at 1.3 specific gravity performed by the EERC on Czech lignites from Bílina and Nastup achieved 23% to 48% reduction in ash and 23% to 43% reduction in sulfur at energy recoveries of 89% to 93%. Dry magnetic cleaning was less effective for these lignites. Tests on a combination of wet gravity cleaning and acid washing performed by the EERC on U.S. low-rank coals achieved 60%–80% ash removal and 30%–80% sulfur removal to produce products with typically 2%–3% ash and 0.2%–0.5% sulfur. The combination of cleaning by polar oil agglomeration and acid washing yielded even lower ash levels in the range of 1%–2%.

Drying and Carbonizing

Thermal upgrading of lignite has long been viewed as a principal prospect for overcoming problems of transportation and utilization relating to high moisture and low heating value. Commercial dryers that are suitable for evaporatively drying lignite under conditions where the temperature of the lignite remains below 100°C include rotating drum, fluidized-bed, entrained-flow, steam-tube, and beater-mill designs. These low-temperature drying methods have found limited application in the production of transportable upgraded fuels because of the instability of the dry coal product produced, which is very dusty and prone to moisture reabsorption and spontaneous ignition. In an effort to reduce these problems, a number of drying and pyrolysis processes operating at higher temperatures have been recently investigated in the United States, including the Syncoal process (which both dries and removes pyritic sulfur), the K-Fuel process, the LFC/Encoal process, the FMC process (producing form coke), and variations on coal pyrolysis studied under the U.S. DOE Mild Gasification Program. The combination of decarboxylation and tar migration occurring at temperatures above 240°C yields a more stable dried material, but some form of briquetting is still required to produce products with good handling and storage characteristics.

The most promising carbon products that can be produced for different markets based on drying, carbonizing and briquetting technologies are premium lump boiler fuel, smokeless briquettes, dry lignite powder, metallurgical form coke, and activated carbon. Marketable pyrolysis liquids can also be produced, but the cost of processing cannot be significantly offset by selling coal-derived liquid fuels at current petroleum price levels. In the United States, premium boiler fuels with a low sulfur content and high calorific value are being produced from low-rank coals under the DOE Clean Coal Technology Demonstration Program for test marketing to utilities and industrial plants; these markets are economically feasible in the United States only because of alternative-fuel tax credits. There is a potentially large market for residential smokeless fuels in East Central Europe, estimated as high as 50 million tons annually. Some smokeless briquettes of varying quality are produced in the Czech Republic, Poland, and Germany, but there is still an urgent need to address dispersed air pollution from household use of high-sulfur lignite and smoky briquettes in the former East Germany, Hungary, Bulgaria, Romania, and the Ukraine—which represents a market for coal cleaning, carbonizing, and additive technologies that can meet environmental and cost requirements. The production of dry lignite powder in the Czech Republic and Germany for use in the cement industry and other industrial applications could potentially be expanded by integrating coal cleaning to meet a wider range of customer needs. High quality metallurgical form coke with suitable strength and low sulfur and ash contents can be manufactured from selected low-rank coals, which would help to address heightened concerns over emissions from conventional slot-type coke ovens. Activated carbons, which depending on quality can have a value up to US$1000–US$2000/ton, are being produced from U.S. Gulf Coast lignite; entry into this low-tonnage high-value market depends on meeting stringent end-use specifications, including requirements for new applications as air toxic metal sorbents.

Low-Rank Coal–Water Fuel (LRCWF)

Coal–water fuel is a mixture of finely ground coal in water. CWF was originally produced only from subbituminous coal owing to the low energy density product resulting from slurrying high-moisture lignite in additional water. The technology for producing LRCWF from brown, lignitic, and subbituminous coals by irreversibly expelling water from lignite by heating pulverized coal-grind coal in saturated hot water at about 285°C and 75 bar pressure was developed by the EERC and demonstrated in a 6-ton/day pilot plant. Sufficient quantities of product were produced for testing in oil-fired boilers, and experimental coal slurry-fired diesel and turbine engines, indicating that the LRCWF had excellent combustion characteristics in terms of flame stability and carbon burnout. The economics of LRCWF allow it to compete with bituminous coal–water fuel or heavy oil, but not directly with coal. A potentially large market for LRCWF exists in Europe and around the world because of the many oil-fired utility boilers that are not fully utilized. In the Czech Republic, LRCWF made from selected lignite feedstocks that can be gravity cleaned to low levels of ash and sulfur could potentially be marketed for industrial boilers currently burning fuel oil.

Synthetic Liquid and Gaseous Fuels from Coal

Opportunities for synfuels are severely limited by low world prices for petroleum and natural gas. Production of manufactured gas in the Czech Republic is predicted to decline. Continuing production of synthetic pipeline gas (methane) from lignite at the Great Plains Gasification Plant in the United States is made possible only because of the government's substantial contribution to the original cost of plant construction and continuing payments from pipeline customers above the market price for gas, which will lapse within a few years. Plans are being developed for converting the Great Plains plant to the production of liquid hydrocarbons, methanol, and ammonia, along with by-product phenol and other low-volume chemical products. A similar strategy could be considered by Czech coal gas plants. A longer-term opportunity may be afforded by research findings at the EERC on the direct hydrogenation of lignite, which hold the promise of developing a low-severity liquefaction process specifically matched to the chemistry of low-rank coals that can be cost-competitive with petroleum in the not-too-distant future.

Humate Products

Oxidized lignite can be processed to produce a large number of humic acid products, ncluding soil conditioners, fertilizers, ion-exchange media for heavy metals, additives for drilling mud, binders, water treatment chemicals, odor control agents, and other products based on the properties of humates. Important humate properties include cation exchange, pH buffering, water retention, adsorption, nutrient transfer in plant physiology, and viscosity control in non-Newtonian liquids and gels. Research already under way on lignite humates in the Czech Republic may lead to the development of new businesses producing high-value specialty chemicals from lignite humates.

Coal Combustion By-Products

The commercial value of coal combustion by-products, including fly ash, bottom ash and desulfurization products (AFBC and FGD), has been well established by research and engineering practice. The use of fly ash in concrete and other construction materials enhances strength and durability while reducing cost. Ash and gypsum products can improve the tilth of clayey soils. Their cementitious and pozzolanic properties serve to immobilize hazardous metallic and organic wastes. Manufactured products can incorporate combustion by-products in all forms of cast concrete products, blended masonry cements, aggregate, mineral wool, gypsum wallboard, brick and other ceramic products, and fillers in metal and plastic castings or extrusions. There is a need in the United States, and possibly in the Czech Republic, for environmental and engineering standards to encourage more extensive reuse and recycling rather than disposal of a variety of materials heretofore categorized as wastes. The environmental safety of most combustion by-products has been established by research and practical experience, but additional regulatory definition is needed to establish comparability with cement, rock, and other construction materials. An emphasis on beneficial use of coal combustion by-products in the Czech Republic can provide important environmental and economic benefits in terms of improved waste management and efficient resource utilization.

ADVANCED POWER ASSESSMENT FOR CZECH LIGNITE

1.0 INTRODUCTION

The United States has invested heavily in research, development, and demonstration of efficient and environmentally acceptable technologies for the use of coal. This effort, involving the U.S. Department of Energy (DOE), as well as numerous U.S. industrial groups, has placed U.S. technology in a leadership role worldwide. The United States has the opportunity to use its leadership position to market a range of advanced coal-based technologies internationally.

At the same time, coal-mining output in the Czech Republic has been significantly decreasing. This decrease in demand can be attributed mainly to the changing structure of the Czech economy and to environmental constraints. By the year 2000, black coal production is estimated to be at 14.5 million tons and brown coal to be at 50 million tons, a reduction from 1993 levels of 18 and 67 million tons, respectively. The continued production of energy from indigenous brown coals is a major concern for the Czech Republic. The Czech Republic's strong desire to continue to use this resource is a challenge, but fortunately high-technology, value-added equipment and services are available from American partners.

Recent discussions with key groups in the Czech Republic, including the Czech Mining Association, have identified the following key needs:

- Identification of proven technologies that would be cost-effective options for the utilization of native Czech brown and black coals, while at the same time being good environmental performers.

- The necessity that all technologies identified meet environmental objectives consistent with the Czech Republic and European Union environmental laws.

- Identification of costs associated with the various technology options and possible financing alternatives, including financial approaches, possible funding institutions, and business configurations.

In an effort to meet these needs, the Energy & Environmental Research Center (EERC) undertook two major efforts. One effort involved an assessment of opportunities for commercialization of U.S. coal technologies in the Czech republic. This report is the result of that effort. The technology assessment focused on the utilization of Czech brown coals, since their abundance and low cost make them the most viable fuel for the Czech power industry. These coals are high in ash and sulfur, and the information presented in this report focuses on the utilization of these brown coals in an economically and environmentally friendly manner. Sections 3–5 present options for utilizing the as-mined coal, while Sections 6 and 7 present options for upgrading and generating alternative uses for the lignite.

The second effort undertaken by the EERC to help meet the needs identified by the Czech Republic was the presentation of two workshops in Prague. These workshops, entitled "Least-Cost Economic Power Generation in East Central Europe" and "Production and

Utilization of Ecological Fuels from East Central European Coals," provided an excellent opportunity to identify issues and solutions leading to the formulation of partnerships involving U.S. industry and Czech Republic industries. The proceedings of this conference are available from the EERC.

2.0 CZECH REPUBLIC NATIONAL ENERGY PERSPECTIVE

Energy trends and developments in the Czech Republic have been reported in some detail in two recent study reports prepared by the International Energy Agency (IEA, 1994; Daniel and Jamieson, 1992), and related topical information is available from many other sources (Czech Ministry of the Environment, 1993; Walker, 1993; U.S. DOE, 1993; U.S. EIA [Energy Information Administration], 1995; U.S. EPA [Environmental Protection Agency], 1992; U.S. Senate, 1991; IMF [International Monetary Fund], 1993; Brix, 1992; World Bank, 1991; Couch, 1988). Major reforms have been initiated to reverse the 40-year legacy of central planning, which includes subsidized energy pricing, unchecked pollution from coal burning plants, questions regarding safety of Soviet-built nuclear reactors and management of spent fuel, and dependence on the former U.S.S.R. for oil, gas, and the nuclear fuel cycle. Changes in the energy sector are evolving within the framework of a general transition to a market economy. Progress has been made in reducing the role of the state in energy supply and distribution, but the pace at which price subsidies will be eliminated and government control relinquished is still unclear. Regulated prices for petroleum products, especially gasoline, are higher than U.S. prices but low by western European standards. Prices for electricity, heat, and natural gas paid by industry are close to western levels, but the same prices for households are as much as 40% lower and well below economic cost. A well-defined regulatory framework for utility companies is not yet in place. Restructuring of coal mining to close uneconomic operations requires continuing government assistance. The Czech Power Works Company (CEZ) has developed plans to retrofit pollution controls on newer coal-fired power plants and to shut down obsolete plants when new nuclear units are commissioned. Long-term policies affecting energy prices, privatization, conservation, supply diversification, environmental cleanup, and nuclear safety are still in development as the Czech Republic endeavors to establish a market economy while avoiding unacceptable social and economic impacts.

2.1 Transition of the Czech Economy

The overall economic condition of the Czech Republic has stabilized and is improving despite the difficulties involved in restructuring the economy and the separation of the former Czech and Slovak Federal Republics in January 1993 (IEA, 1994). Gross domestic product (GDP) increased by 2% in 1994 after dropping by 22% between 1989 and 1993. The GDP growth in the first half of 1995 of 4% clearly indicates an accelerated growth of the Czech economy. Unemployment is the lowest in the region, at 3.5% in April 1994. However, real wages have fallen about 20%. Annual consumer price inflation peaked at 21% in 1993 because of the monetary shock following the Czech and Slovak defederalization, but then dropped back below 10% in 1994. A positive current account balance of $600 million was achieved in 1993 as the result of $983 million in foreign investment offsetting a modest $245 million trade deficit. The government's external debt is only 4% of GDP.

Privatization of small business was completed in 1992, and larger enterprises were partially divested from government ownership in 1993 and 1994 through direct sales to domestic or foreign investors and vouchers distributed to the public. Proceeds from privatization are being placed in the National Property Fund to be used for restructuring the economy. The state at present retains a controlling interest in major energy enterprises, including 100% ownership of oil refining, distribution, and marketing; 100% of the Transgas

Pipeline Company; 70% of the Czech Power Company; and about 50% of "unbundled" gas and electric distribution companies and coal-mining companies.

The ultimate goal is to move toward government-regulated, investor-owned companies under arrangements that raise needed capital but retain a "strategic stake" for the state. Foreign firms are not expected to acquire a controlling interest in Czech energy companies at any time in the near future. The privatization of distribution companies will continue for both domestic and foreign companies, and the government also plans a significant decrease of its stake in coal companies.

The downturn in the economy after 1989 was caused largely by a collapse in energy-intensive industrial production, and recovery is paced by improvements in consumer trade, services, light industry, and construction. Steel production dropped 30% between 1989 and 1992, along with substantial declines in other metals and mineral products including copper, nickel, tin, uranium, zinc, coal, and agricultural fertilizers (U.S. Bureau of Mines, 1992). Consequently, energy demand after declining to three-fourths of its 1987 high remains at a 20-year low. 1994 and 1995 energy statistics indicate some growing trends.

2.2 Resources and Energy Supply

Although energy use in the Czech Republic has declined, it is still 2–4 times higher in relation to industrial output than in OECD (Organization for Economic Cooperation and Development) countries. Primary energy supplies in 1993 were estimated by the IEA to be derived 53% from lignite, 11.5% from hard coal, 14.5% from oil, 13% from gas, 7.5% from nuclear, and 0.5% from hydroelectric power (IEA, 1994). About one-third of this energy is imported, including almost all oil and gas, which is still obtained primarily from the former Soviet Union. Coal, which is the main domestic source of energy, is projected to provide a declining share of total energy requirements. Nuclear energy has developed rapidly since 1978 and will expand further with the completion of two 1000 MW reactors after 1998.

2.2.1 Coal

Czech coal reserves of 2340 million tons of lignite and 980 million tons of hard coal (IEA, 1994) would last for approximately 30 and 50 years, respectively, if current production rates were maintained and considerably longer with contraction of the coal industry. Mining conditions are generally economically favorable for lignite but not for hard coal. The reported quality of lignite varies widely on a dry basis, from 0.4% to 6% sulfur and 7% to 44% ash (Young and Musich, 1995; IEA, 1994; Couch, 1989). The better lignite reserves are located in the Most region of North Bohemia (1800 million tons) and the better hard coal reserves at Ostrava in Moravia (900 million tons). Significant reserves of lower-quality lignite are found in the Sokolov region of western Bohemia (470 million tons).

Total coal production declined by 24% between 1989 and 1993 (from 112 million to 85 million tons), reflecting a 23% drop for lignite and 27% for hard coal (IEA, 1994). Traditional markets for lignite in the Czech Republic, unlike those in western countries, are not dominated by electric power generation (55% of lignite consumption), but involve many smaller users, such as district heating plants, industries, public institutions, and even households. Hard coal demand in 1993 was divided between 40% steam coal and 60% coking coal. Czech hard coal production for both domestic and export markets faces strong price competition from lower-cost foreign coal producers and natural gas. Lignite mines producing lower-quality fuel are very dependent on the nonpower market, and government policy appears to favor converting a significant part of this market to natural gas for reasons of efficiency and environmental protection. Some projections of domestic coal use to 2005 indicates a substantial further decline of 45% for lignite (61 million to 33 million tons) and 35% for hard coal (15 million to below 10 million tons). Restructuring of the industry up until 1994 had led to the closure of nine underground hard coal mines (down from 24 to 15 mines) and one surface and five underground lignite mines (20 to 14 mines), with a commensurate drop in total employment from 195,000 to 105,000 (IEA, 1994). Continued dramatic downsizing is projected to force employment levels down as low as 15,000 by 2010 in three large lignite surface mines producing a total of 30 million tons annually and three large underground hard coal mines producing 5 million tons (IEA, 1994). The most important question will be the creation of alternative employment for displaced miners. Both the social welfare of the miners and the economy of the Czech Republic can be greatly benefited by finding new environmentally acceptable applications for lignite, the only known large economic domestic energy resource, in both advanced power systems and manufactured products.

Lignite is expected to maintain a significant position in coal-fired power plants and combined heat and power (CHP) plants owing to its availability and relatively low cost, typically US$1/GJ for lignite compared to US$1.50/GJ for hard steam coal and US$3.00/GJ for natural gas. The characteristics of lignites from northern and western Bohemia are shown in Table 1. These coal analyses were used as the principal basis for the assessments performed under this study.

2.2.2 Natural Gas

Demand for natural gas, which competes with coal rather than oil in the Czech Republic, is expected to grow at a rate of 6%–7% annually out to the year 2005, paced by industrial, district heating, and CHP plants. The highly subsidized household gas market is not profitable and will not expand rapidly unless prices are deregulated. Future escalation in the price of natural gas will have an important effect on the national economy and the choice of fuel supply, including the use of coal in future heat and power generation.

The Czech Republic remains dependent on Russia for the majority of its gas supply. Domestic natural gas production is expected to continue to supply only about 2% of demand. Manufactured gas (blast furnace gas, coke oven gas, town gas, and other sources) which represented 27% of the total gaseous fuel supply in 1992 on an energy basis will decline in the future. Future options that are being explored to reduce concentrated dependence on Russian gas supplies include imports from Kazakhstan, Norway, or other North Sea suppliers; coal bed methane; and links to proposed new European pipelines.

The Transgas Pipeline Company operates profitable transit pipelines through the Czech Republic to France and Germany and also operates the high-pressure gas transmission grid within the country. Underground gas storage capacity is equivalent to 3 months average consumption, but maximum withdrawal rates are not sufficient to meet peak winter demand in case of total interruption of imports. Eight recently established regional gas distribution companies face problems of nonpayment from industrial customers and need outside investment

TABLE 1

Lignite Analyses Used for Assessing Czech Least-Cost Power Options

Source:	Young	SD a.s.	Young	Martinek	Martinek	Martinek	Martinek
Year:	1995	1994	1995	1998	1998	1988	1988
Mine/Region:	Bílina	Bílina	Nástup	N. Bohemia	N. Bohemia	Sokolov	Sokolov
Samples:	Average of 4	Range	1	Range	Average	Range	Average
Proximate Analysis							
Moisture, wt% as-mined	30.1	24–30	38.7	6–55	29.4	35–41	37.5
Ash, wt dry basis	7.3	11–43	18.8	26–44	25.5	22–55	36.8
Volatile Matter, wt daf[1]	51.5	52–54	55.3	52–56			
Fixed Carbon, wt daf	48.5		44.7				
Ultimate, wt daf							
Carbon	73.0		69.8				
Hydrogen	6.0		5.5				
Oxygen	18.7		20.9				
Sulfur	1.2		2.1	0.8–5	2.0	1.2–10	3.0
Nitrogen	1.1		1.6				
Total	100.0		100.0				
Sulfur Forms, wt daf							
Organic	0.78	0.5–0.8	1.27				
Pyritic	0.38	0.6–1.0	0.73				
Sulfatic	0.05	0.08–.16	0.15				
Total	1.21	1.18–1.96	2.14				
Heating Value							
HHV,[2] as-mined							
Btu/lb	8442		6173		6505		4802
MJ/kg	19.6		14.4		15.1		11.2
HHV, daf							
Btu/lb	13,032		12,401		12,367		12,156
MJ/kg	30.3		28.8		28.8		28.3

TABLE 1 (continued)

Source:	Young	SD a.s.	Young	Martinek	Martinek	Martinek	Martinek
Year:	1995	1994	1995	1998	1998	1988	1988
Mine/Region:	Bílina	Bílina	Nástup	N. Bohemia	N. Bohemia	Sokolov	Sokolov
Samples:	Average of 4	Range	1	Range	Average	Range	Average
LHV,[3] as-mined							
Btu/lb	7769		5519		5934		4214
MJ/kg	18.1	10.8–17.4	12.8	9–18.6	13.8	9.7–11.7	9.8
LHV, daf							
Btu/lb	11,994		11,087		11,791		11,178
MJ/kg	27.9		25.8		27.4		26.0
Ash XRF[4] Analysis, wt% as oxide							
SiO_2	36.3	45–60	49.8				
Al_2O_3	24.2	23–30	10.9				
Fe_2O_3	10.2	6–14	14.6				
TiO_2	1.2	1.3–2.3	0.4				
P_2O_5	0.6	0.2–0.4	0.8				
CaO	8.0	3–9	7.4				
MgO	4.1	0.2–1.8	2.6				
Na_2O	1.4	0.4–1.1	0.6				
K_2O	1.1	0.6–1.8	0.4				
SO_3	12.8	0.1–2.1	12.5				

[1] Dry, ash-free.

[2] Higher heating value.

[3] Lower heating value.

[4] X-ray fluorescence.

capital to cover equipment modernization (e.g., metering) and conversion from town gas to natural gas.

2.3 Electric Power Generation

At the end of 1993, the total installed electrical generating capacity of the Czech Republic was 14,285 MW (Table 2), comprised 77.6% by coal-fired units, 12.3% by nuclear, 9.6% by hydroelectric, and 0.5% by other source, e.g., gas and oil (Vlcek and Spilkova, 1995). CEZ accounts for 72% of this capacity, independent power producers (IPPs) 15%, and "autoproducers" 13%. This installed capacity provices more than a 30% reserve margin. Nuclear capacity was more fully utilized than coal or hydro in 1994, contributing 27.1% versus 66.5% and 6.4%, respectively, to CEZ power generation (IEA, 1994). The reported generating capacity for CHP plants, 8882 MW_e (IEA, 1994), includes many older generating facilities that see negligible use. Total demand for electricity dropped about 9% from 1990 to 1991 (Daniel and Jamieson, 1992), and industrial demand was 21% lower in 1993 than in 1990 (IEA, 1994). However, total electrical demand increased by about 1% between 1992 and 1994 because of an offsetting increase in residential demand, and it appears that the decline in electricity use may have come to an end. The reference level projection developed by CEZ indicates an average annual growth of 1.6% between 1994 and 2000 (IEA, 1994). The latest trends in consumption indicate that the rate of growth may be significantly higher.

CEZ operates a system of 440-, 220-, and 110-kV transmission lines interconnected with synchronized grids in Slovakia, Poland, Hungary, Romania, Bulgaria, the former Soviet Union, and part of former East Germany. Future goals include improvement in frequency control to be able to synchronize with the West European Power Grid (UCPTE). Power distribution in the Czech Republic is through eight distribution companies that purchase power from CEZ and sell power to end users. Considering the pricing arrangement and the surplus power supply, neither the CEZ nor the distribution companies have an incentive to develop demand-side management programs that would improve long-term supply with existing facilities. However, the delay in construction at Temelin combined with fast-growing demand is depleting the surplus power.

Government energy policies supporting the expansion of nuclear power, replacement of coal by less polluting fuels (e.g., natural gas and renewable resources), installation of flue gas cleaning on selected coal-fired plants, support for CHP cogeneration plants, least-cost

TABLE 2

Electrical Generating Capacity in the Czech Republic (Vlcek and Spilkova, 1995)

	Coal	Nuclear	Hydro	Other	Total
CEZ, MW	7,332	1,760	1,178	--	10,270
IPPs, MW	1,929	--	193	--	2,122
Autoproducers, MW	1,817	--	--	76	1,893
Totals, MW	11,078	1,760	1,371	76	14,285
Totals, %	77.6	12.3	9.6	0.5	

planning, and demand side management will greatly influence the future development of the power industry in the Czech Republic. CEZ has initiated a 1994–2000 development program that includes 1) completion of the Temelin nuclear power plant (2000 MW) under a subcontract with Westinghouse to Skoda Praha as the primary contractor, 2) gradual decommissioning of obsolete lignite-fired plants (2300 MW) coordinated with the start-up of Temelin, and 3) upgrading of remaining coal-fired units scheduled to remain in operation after 1998 (6800 MW). A least-cost development study performed for CEZ (Vlcek and Spilkova, 1995) showed that existing units could be upgraded with emission controls and other measures for addressing a range of availability requirements at less than half the cost of new capacity—including natural gas-fired combined cycle, pulverized coal-fired steam plant, lignite-fired integrated gasification combined cycle (IGCC), or nuclear. The expected outcome of this development program will be to bring all coal-fired units into compliance with the Czech Clean Air Act by the end of 1998 and to allow CEZ to maintain its position as a least-cost supplier of electricity for some years after 2000.

2.4 District Heating Plants

Hot water for heating is supplied to most of the urban population of the Czech Republic by 113 district heating plants, including heat-only and CHP facilities, with capacities ranging from 7 to 1100 MW_{th} and from 0 to 220 MW_e (IEA, 1994). These plants are fueled 67% on coal, 21% on gas, and 12% on oil (Daniel and Jamieson, 1992). Approximately one-third of domestic coal consumption (both lignite and hard coal) is used by heating plants. Many of these plants use low-quality local coal in old and inefficient equipment, and most are in need of rehabilitation or replacement. System upgrading needs include the installation of household metering and remediation of high heat and fluid losses, which together cause heating loads in the Czech Republic to be about 240% higher than in some other industrialized countries (IEA, 1994). Until recently, few plants had any pollution control equipment despite serious emissions problems. Some power plants, including Melnik and Opatovice, operate CHP plants that are being retrofitted with flue gas desulfurization (FGD).

Conversion of district heating plants to natural gas firing, which is encouraged by government policy, has been accomplished in some smaller facilities in Prague. However, in larger plants including CHPs, local lignite priced at about US$1/GJ is competitive with natural gas priced at about US$3/GJ, even with pollution control costs added. In the future, CHP cogeneration plants may represent the best opportunity for applying advanced IGCC and pressurized fluidized-bed combustion (PFBC) technologies in the Czech Republic.

2.5 Environmental Goals

The priorities of the Czech Ministry of the Environment are targeted first on air quality impacts caused by coal combustion—followed by air, soil, and groundwater impacts due to coal and uranium mining, oil refining, and petrochemical processing (IEA, 1994).

Serious air pollution is estimated to affect the health of 20% of the population adversely, and Prague is reported to have the highest average concentration of air pollutants of any European capital. Air pollution is particularly severe in the lignite-burning region in Northern Bohemia and Upper Silesia, also near coking plants in Ostrava, and in urban areas where coal or briquettes are burned for space heating. Air quality improvement goals are 1) to eliminate smog and critical air pollution episodes in urban areas, 2) to gradually reduce pollution to levels that protect long-term health and the natural environment, and 3) to comply with international agreements on transboundary air pollution (Vejvoda, 1994). The air emissions of most immediate concern are SO_x, NO_x, and particulates from large coal-fired utility and district heating boilers and volatile organic carbons (VOCs) from road vehicles, coke plants, and coal-burning space heaters. Mercury and arsenic have also been identified as air pollution concerns.

Soil and groundwater remediation goals are concerned with coal mine reclamation, coal cleaning wastes, underground mine subsidence (Northern Moravia), in situ acid leaching of uranium, and heavy hydrocarbon and benzene wastes discharged from refineries.

Environmental legislation passed in 1989 and 1992 reversed the past practice of relying on pollution dispersion using tall stacks and instead established source emission standards and implementation guidelines based on principles of "the polluter pays" and "best available technology not exceeding reasonable cost" (BATNERC). Emission standards applying to large new coal combustion sources (100 mg/m^3 particulate, 500 mg/m^3 SO_2, and 650 mg/m^3 NO_2) are close to European Union (EU) standards.

3.0 REPOWERING

Competition in the power supply marketplace is spurring many electric utility decisions. Regulators are also exerting some control on the industry. Acting in concert, recent regulatory and market forces are creating a scenario favorable to repowering, reinforcing its viability as an option for competitive utilities. The significant forces behind repowering include:

- A future need for new capacity.
- A favorable link between repowering and environmental compliance strategies.
- A growing source of cost-effective repowering projects because of the age distribution of existing fossil-fueled units.
- The likelihood of further clean air legislation limiting emissions of CO_2 and other greenhouse gases.
- The comparative economics of greenfield power plants vs. repowering facilities greatly favoring the latter.
- The difficulty in siting and permitting new power plants

The following discussion assumes these forces will create a significant market for repowering and discusses repowering options available to the electric utility company.

3.1 Repowering Defined

Repowering offers utilities an option for their aging power plants besides decommissioning—an option that can cut emissions while boosting plant efficiency, reliability, output, and service life. Older, less efficient plants, candidates for repowering, are low on the dispatcher's list. If repowering moves the unit from the bottom to the top, then its capacity factor, fuel costs, overall site emissions, labor, and water consumption move up too. Therefore, not only is the life of the unit extended by repowering, but the plants value to the utility is greatly enhanced.

Repowering is defined here as options for an old, but still serviceable, steam cycle to 1) improve efficiency significantly and/or 2) expand capacity while 3) obtaining a more favorable environmental profile. Several repowering schemes are available, but the most common ones that utilities are considering for fossil fuel-fired steam/electric units focus on replacement of the original steam generator with one of the following: a gas turbine/generator and heat recovery steam generator (HRSG), an atmospheric fluidized-bed combustor (AFBC), an IGCC, or a PFBC/combined cycle (PFBC/CC). The repowering options include partial repowering–replacing a boiler with an HRSG coupled to a gas turbine; station repowering–use of the existing infrastructure but not the original steam cycle; and site repowering–reusing an existing site but none of the original equipment.

Gas turbine combined-cycle power plants are considered the most prominent repowering strategy. The benefits of a natural gas-fired combined-cycle facility include rapid load change and start-up capability, high reliability, low emissions, and high efficiency. Repowering with an advanced gas turbine and/or generators and HRSGs can improve the overall plant thermal efficiency by as much as 20%, with tripled plant output in some cases.

The technical challenge in any repowering project is the successful integration of new and existing equipment based on economic, efficiency, reliability, and emissions criteria. Most repowering applications have used the existing steam turbine generator, condenser, and cooling systems. In some cases, the steam turbine generator was replaced, but major parts of the balance-of-plant equipment, foundation, and building were retained. The remainder of this chapter focuses on several repowering schemes.

3.2 Recent U.S. Repowering Projects

A review of recent repowering projects in the United States reveals options for all forms of fuel. Oil-/gas-fired boilers at Florida Power & Light Company's Lauderdale Station were replaced with gas-fired gas turbine/HRSG trains. The same is happening at New Jersey Public Service Electric & Gas Company's Bergen Station and is planned for San Diego Gas & Electric Company's Spluth Bay Station. At Virginia Power Company's Chesterfield Station, two small coal-fired boilers, retired at the time of repowering, became part of gas-fired combined-cycle plants.

Gas-fired boilers at Gulf Power Company's Nelson Station were replaced with petroleum coke-fired circulating fluidized-bed (CFB) boilers. Several pulverized coal-fired boilers were replaced with coal-fired bubbling and circulating FBCs in recent years. Additionally, the DOE Clean Coal Technology Demonstration Program is demonstrating repowering of coal-fired steam cycles by application of both coal gasification and PFBC of coal.

In Europe, many repowerings involve addition of a gas turbine exhausting into the existing fossil-fired boiler. This is commonly referred to as the "hot windbox" or turbocharged boiler repowering concept. This has not been a major priority option in the US, but could be. The Midland Cogeneration Venture has converted two large nuclear steam turbines into a gas-fired combined-cycle arrangement. Although Midland was never completed as a nuclear facility, several operational nuclear plant steam turbines are planned for repowering with gas turbines/HRSGs.

Repowering is essentially resulting in the incremental gain in relative importance of the Brayton cycle over the Rankine cycle. The common denominator in most of the repowering projects is the addition of gas turbine/generator capacity, either to a conventional fossil fuel-fired or nuclear steam generator-steam turbine-based plant.

3.3 Addition of Gas Turbines

Integrating gas turbines and HRSGs with an existing steam turbine/generator to produce a combined-cycle unit is by far the most common type of repowering project that utilities have implemented. Gas-turbine based combined-cycle repowering projects range in size from 40 to 1600 MW, depending on the number and size of the turbine/generators involved. Replacing aging steam generators with HRSGs generally eliminates reliability issues associated with aging units and permits a switch to natural gas.

Gas turbines can be easily integrated and operated in combination with steam cycles. The three main plant repowering concepts utilizing gas turbines include repowering with an HRSG, repowering with a fully fired steam generator, and repowering with feedwater preheating. When properly designed, all three repowering concepts can provide up to 50% additional output. For a 150-MW gas turbine, for example, approximately 75 MW can be recovered from the unit's exhaust energy.

The application of these concepts reveals the potential performance of repowering with one 150-MW gas turbine for a wide range of plant sizes. The combined-cycle arrangement with HRSG provides the best performance and offers up to 54% net efficiency. The fully fired combined-cycle arrangement (hot wind-box) is optimized when a 150-MW gas turbine is installed as a part of a 600-MW unit. The feedwater preheat arrangement can be applied to a wide plant-capacity range and can increase plant efficiency as the host plant's size becomes smaller. These repowering concepts all lead to significant emission reductions, especially when natural gas or gasified fuel is used.

As with most market trends, the technical evaluation related to these repowering options reveals many challenges. As a rule of thumb, the more the existing steam cycle is relied upon, the more difficult the repowering will be. The most basic challenge is to match the old steam cycle parameters to the new part of the plant. In the case of gas turbine/HRSG repowerings, the thermal output of the HRSG must be matched to the existing steam turbine/generator. Steam turbines are generally custom-designed for the desired output. Gas turbines, on the other hand, come in discrete sizes, each characterized by a specific exhaust energy flow available to generate steam. How well this steam flow, or combination of steam flows, matches the present-day characteristics of the steam turbine determines the efficiency and output of the repowered unit.

Ways of getting around the discrete size limitation of gas turbines are 1) the use of supplementary firing of the HRSG, 2) injecting steam into the gas turbine if excess steam is available, and 3) employing evaporative coolers and/or inlet air chillers to augment the power available from the gas turbine, depending on ambient temperature. All will add to the cost and complexity of the retrofit and influence the ultimate unit heat rate. Steam or water injection into the gas turbine, for instance, imposes higher maintenance costs on the gas turbine and greater water treatment needs.

Excess steam also can be used to drive a boiler feed pump, and existing motor drives can be replaced with a steam turbine drive, depending on the relative worth of electricity and steam at the site. Alternatively, the steam turbine can be uprated or derated using a variety of techniques, including replacing steam path components to accomplish high duty, operating the steam turbine at reduced last-stage steam flows, and so on.

These repowering concepts are well suited to plants that satisfy midrange power demand because the plant's best net efficiency is achieved when the gas turbine is at about full load and the steam turbine is at half load. Plant load cycling in the 35% to 100% range is possible with the gas turbine output being lowered to not more than 50% of its rated load.

If the turbine's exhaust energy in a feedwater preheat repowering application cannot be recovered efficiently in one steam turbine, it can be divided between two steam turbines. The recoverable gas turbine exhaust energy is split in half, and the capacity of each of the two steam cycles has only to be increased by one-half of the total gain. This can be more easily achieved without reaching low-pressure (LP) turbine, cooling water supply, generator or transformer limits.

3.4 AFBC Repowering/Impacts of Coal Properties on CFBC Performance

Repowering with an AFBC is an alternative that gives plants a fuel choice while meeting stringent emissions requirements. In particular, SO_2 emission can be reduced by 90% or more by injecting limestone or other sorbents into the turbulent burning fuel stream. The relatively low furnace temperatures of these systems (1450° - 1700°F) help keep NO_x levels low, typically below 0.3 lb/MMBtu. NO_x emissions can also be further reduced by a factor of 10 or more by employing selective catalytic reduction (SCR) with ammonia or urea injection. This allows even the most stringent emission requirements to be met.

AFBCs have reached commercial maturity over the last decade and are generally considered relatively low-risk technology for repowering. In fact, operating staffs familiar with conventional boiler technology typically have few, if any, problems adjusting to AFBCs. Most single-unit AFBCs now serve plants smaller than 100 MW. Several plants in the 150- to 180-MW range are now in operation, and advanced designs are available to produce enough steam to power a 300–400 MW steam turbine/generator.

Several utilities in the United States have been successfully converted to AFBC plants utilizing western U.S. subbituminous and lignitic coals: the 125-MW Black Dog plant in Minnesota, the 80-MW Heskett plant in North Dakota, and the 110-MW Nucla plant in Colorado. All of these repowering projects used partial repowering. In the case of the Heskett plant, almost all of the original steam generator and turbine was reused. At the Black Dog plant, a portion of the original steam generator was reused, as was the original turbine. At Nucla, the original steam generator was totally replaced by the AFBC and new turbines added to increase the total plant output.

Thermal and environmental performance and operating costs of an atmospheric CFBC are functions of operating conditions, design parameters, and fuel properties. Design parameters are selected/optimized before fabrication and installation of a system, while operating parameters are manipulated after the system is installed. Obviously, a combination of expected operating parameters must be specified in order to design the system to deliver the desired rate and form of energy while meeting the required emission standards. Likewise, the design fuel, and any other potential fuels that may be used in the system, must be specified prior to design of the system, as fuel properties can have a significant impact on the design and operation of a CFBC. These "design-point conditions" are projections from pilot-scale tests, extrapolations from similar fuels or systems, or copies of existing successful systems.

The main purpose of this section is to discuss the differences that exist among fuel properties and to relate these differences to the design and performance of a CFBC. Knowledge of specific properties will be critical in the design phase, while an understanding of other properties will be more critical during operation. A summary of the effects of coal properties on CFBC system design and performance is presented in Table 3.

3.4.1 Thermal Performance

Because of the action of the circulating solids, CFBCs typically operate with a high heat flux. The heat flux for full-load conditions ranges from about 25,000 to 35,000 Btu/hr ft^2. The heat flux increases with increasing temperature and velocity, but is generally independent of fuel type. Fuel type may indirectly affect heat flux, to a small degree, by its effects on recirculation rates and particle-size distributions. No differences are expected for the variations within the Maritsa mine.

The lignitic coals are typically very reactive, and carbon burnout approaching 100% is achieved. It is anticipated that high carbon burnout will be accomplished with the Czech lignite. Factors affecting the carbon burnout for this coal will be the relatively high ash and sulfur levels, which result in a high solids removal rate. Because the carbon content in the bed is typically around 3%, high-solid drain rates will result in higher unburned carbon losses. Several fluid-bed heat exchanger/bed removal systems have been designed and are offered as options to CFBCs. These systems increase efficiency by providing an opportunity to burn off residual solids and to capture the sensible heat in the bottom ash before discharge. A cost/benefit analysis of using such a system is warranted.

A modified version of ASME (American Society for Testing and Materials) PTC 4.1 is used to calculate boiler efficiencies for CFBCs. Overall boiler efficiencies are affected by the carbon burnout of the fuel and a number of other parameters. Since low-rank coals (LRCs) typically contain high levels of moisture, more heat is required (lost) during the combustion of low-rank coals to vaporize the extra moisture. When operating at a specific temperature and excess air, the high-moisture fuels generate greater mass flows through the system per delivered Btu than low-moisture fuels, resulting in a higher fraction of the energy being recovered in the downstream convective heat recovery unit. The amount of generated energy which ends up in the flue gas can vary from 65% for fuels with 40% moisture to 40% for the relatively dry bituminous coals. The shift of energy results in a reduction of boiler efficiency due to greater stack losses for the high-moisture coals. Other losses in boiler efficiency result from the conversion of fuel hydrogen to water, unrecoverable heat from the discharge of ash and spent sorbent, and the calcination of the raw sorbent. A boiler efficiency credit is given for the sulfation of the sorbent, as this process produces usable heat. The Czech lignites will lose efficiency because of the high ash, but will probably see little sorbent-related reduction in boiler efficiency.

Coal properties will have an effect on the initial design of a CFBC and the operation of an existing system. For example, a system designed for the high-moisture fuel would require a larger fuel feed system to generate the same amount of steam and/or electricity as a unit designed for a low-moisture fuel. Downstream heat recovery equipment would have to be larger for higher-moisture Czech fuels to account for the higher flue gas flow rates. No ash recycle from secondary cyclones or baghouses will be required to obtain acceptable levels of carbon burnout.

TABLE 3

Effects of Coal Properties on CFBC System Design and Performance

Coal Property	Effect on System Requirements and Design	Effect on System Thermal Performance	Effect on System Environmental Performance
Heating Value	Determines size of feed subsystem, combustor, particulate collection equipment, and hot duct.	Efficiency impacted by moisture and ash content (see below).	Determines size of particulate collection devices.
Moisture Content	Can impact feed system design and capacity and size of convective pass.	Higher moisture lowers thermal efficiency.	Very high moisture can increase CO emissions because of afterburning.
Ash Content	Determines size and type of particulate control subsystem and size of ash-handling subsystems.	Higher ash lowers thermal efficiency via heat losses from hot-solids removal.	None, with proper design.
Volatile/Fixed-Carbon Content	Impacts fuel feed method.	Lower combustion efficiency for fuels with low V/FC content.	None, with proper design.
Sulfur Content[1]	Determines required capacity of sorbent subsystem and ash-handling subsystem.	Higher sulfur can lower thermal efficiency via heat losses from added solids for SO_x control (see ash content above).	None, or proportional,[2] if site and system size are regulated. Determines SO_2 emissions (in conjunction with alkaline ash) if uncontrolled.
Nitrogen Content	None, with common designs and typical regulations.[3]	None, with common designs.[3]	Impacts NO_x emissions.
Chlorine Content	Can impact selection of materials for cool-end components. May cause higher corrosion rates for in-bed tubes.	Typically none. Very high chlorides can lower thermal efficiency by requiring operation at higher exhaust temperatures.	Impacts HCl emissions.
Alkaline Ash Content	Can reduce size of sorbent subsystem.	None.	Higher ash alkalinity lowers uncontrolled SO_x emissions.
Sodium and Potassium Content	High sodium can dictate fouling prevention measures and allowance for agglomeration (e.g., sootblowing, frequent bed draining, aeration of downcomer).	Higher sodium can lower thermal efficiency because of tube fouling and heat losses from more frequent hot-solids removal.	Higher sodium lowers uncontrolled SO_x emissions. Sodium tends to reduce fly ash resistivity for ESP performance improvement, may also enhance fabric filter performance.
Ash Fusibility	Low fusion temperatures can impact design, because of allowance for fouling and agglomeration potential.	Lower fusion temperatures impact thermal efficiency in the same way as higher sodium content.	Typically none.

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[1] The forms of sulfur can have an impact, with high pyrite content requiring longer gas residence time in the bed. The result may be increased operating pressure and blower capacity.

[2] Sulfur content can determine SO_x emissions, depending on which regulation applies (e.g., U.S. New Source Performance Standards [NSPS] regulations stipulate fractional removals).

[3] For low-NO_x regulations, a staged combustion or postcombustion NH_3-based suppression design may be required. Staged-combustion designs can have higher CO emissions. Postcombustion NO_x suppression subsystems can lower the thermal efficiency slightly and do emit NH_3.

3.4.2 Environmental Performance

Emissions from a CFBC operating on a given fuel can generally be controlled using proper system design and operation. While system requirements are dependent upon coal properties, the actual emissions are dependent upon the system design and operation. It is currently possible to meet all present and proposed Czech standards with state-of-the-art CFBC technology.

While firing coals in a CFBC, the amount of sulfur capture is primarily determined by the total alkali-to-sulfur ratio. The alkali is provided by the mineral matter and cations contained within the coal and any added sorbent. The forms of alkali in the coal and combustor operating conditions, primarily temperature, are also important. Once the coal and sorbent properties are known, system design and operating specifications can be set to achieve virtually any level of sulfur capture. Although theoretical sulfur captures approaching 100% can be achieved, typically 90% to 95% capture is considered economical in an FBC.

In specifying design and operating conditions for the CFBC, it is critical to know how much sorbent addition is required to meet applicable emission standards. This can vary greatly with coal and sorbent types. For example, test data on various fuels at the EERC show that to retain 90% sulfur, the required alkali-to-sulfur ratio ranges from 1.4 to 4.9, depending on coal type, and an alkali-to-sulfur ratio of 2–3 may be needed. Pilot-scale testing can verify the required sorbent quantities.

The source and size of limestone can also have an impact on sulfur capture. As a part of testing performed at the EERC, two different limestones were tested while a bituminous coal was burned. Limestone size was also a test parameter. Using a coarse limestone (–20 mesh), 40% of the calcium in the limestone was utilized for sulfur capture. A fine limestone (–40 mesh) of the same type resulted in a sorbent utilization of only 29%. A second limestone of fine-particle size (–40 mesh) showed similar performance, with approximately 29% utilization. To capture 70% of the sulfur, alkali-to-sulfur ratios of 1.8 for the coarse limestone and 2.3 for the two fine limestones tested would be required. In this case, the reactivity of the two limestones was similar. The poorer utilization for the finer limestone was probably the result of shorter residence time in the combustor. The collection efficiency for the cyclone decreases with decreasing particle size, and small sorbent particles may leave the system after only one pass. For limestones with different reactivities, the add rates can also vary as a function of limestone type.

When a new unit is designed or when fuel switching is considered with a CFBC, it is important to understand the characteristics of the coal and the sorbent to be used. The alkali-to-sulfur ratio will have the greatest impact on sulfur retention and emissions. However, the required alkali-to-sulfur ratio will depend greatly on fuel properties and can also vary significantly with limestone properties. Likewise, the utilization of sorbent alkali can vary between sorbents and have a significant effect on the amount of sorbent addition required. It is, therefore, recommended that new designs or new fuels be based on either pilot plant testing of that specific fuel and sorbent combination or on operating data from an existing plant burning that or a very similar fuel. This is critical for the Maritsa design since the limestone feed requirements are so high.

NO_x emissions from CFBC are inherently low, and experimental work and recent experience from operational CFBC facilities have indicated that NO_x emissions beyond the low thermal NO_x background levels can be controlled by the proper design and operation of CFBC systems such as staged combustion. This indicates that CFBC systems will not be limited by NO_x emissions and that fuel properties only determine the system requirements to achieve the desired level of NO_x emissions. Several types of postcombustion NO_x-suppressant subsystems can also be applied to CFBCs if further reduction of NO_x emissions is required. This indicates that although NO_x emissions are fuel-specific for a specific design and operating scenario, the emissions can be controlled within a given range by proper design and operation.

3.5 Coal Gasification/Combined Cycle

Several distinctly different choices for IGCC repowering are available. Typically, IGCC involves the replacement of a coal-fired boiler with the gasification process, gas turbines, and HRSGs. Integrating the gas turbine into the gasification process requires careful attention and planning, as does integration of the gasifier and companion gas turbine into the existing steam cycle.

In order to maximize plant efficiency, advanced IGCC plants may utilize air from the gas turbine compressor outlet as a portion of the necessary process air. As a result, compressors and other components designed for optimum performance while firing natural gas may differ significantly from those designed to fire coal gas. Other differences between an IGCC and natural gas-fired combined cycle include the emissions profile and waste streams. One key advantage of a repowered IGCC over the traditional coal-fired plant it replaces is the removal of sulfur from the syngas before it is burned to produce power.

Two repowering projects sponsored in part by DOE focus on repowering existing coal-fired power plants with a coal gasification process, gas turbine/generator, and HRSG. Gasification technologies are discussed in greater detail in Section 5.

3.6 Available Repowering with PFBC

Repowering with commercially available PFBC/CC technology can increase a plant's net heat rate by 10% to 20% and power output by 20% to 25% This technology also offers SO_2 removal efficiencies of over 95% at calcium-to-sulfur ratios as low as 1.1. In addition, NO_x emissions can be maintained in the 0.1 to 0.3 lb/MMBtu range and even lower with add-on controls such as SCR. The technology is similar to AFBC, but the fluidized-bed boiler is contained within a pressure shell.

PFBC developers aim to repower larger steam turbine/generators than IGCC developers do, who are going after projects where 150–200 MW of capacity are added in the form of gas turbines/generators to repower a 50- to 100-MW steam turbine/generator. PFBC technologies are discussed in more detail in Section 6.

3.7 Other Options

A number of other less conventional options for repowering are worth mentioning. Replacing a fossil fuel boiler with a municipal solid waste (MSW)-fired steam generator, adding district heating capabilities, combining diesel engines exhausting into a fossil-fired boiler, and even adding an ultrahigh-temperature steam turbine train are all viable options. In one case, an electric utility and a waste-to-energy (WTE) firm have partnered to repower two idle coal-fired units. Several evaluations of similar arrangements across the United States are under way. If a state-of-the-art WTE plant, with a full slate of acid gas, particulate, and NO_x controls, replaces an uncontrolled fossil-fired boiler, the emissions reduction can be substantial.

For repowering with WTE, output efficiency gains are not the compelling features of the project. Avoiding the equivalent amount of landfilling, reducing emissions at an existing site, and avoiding the permitting and new emissions source of a new WTE plant may be viewed as a great environmental gain. The utility also reaps the traditional benefits of repowering—utility control over generation, favorable financing, least-cost fuel supply, emission offsets, and so on.

Very high overall thermal efficiencies can be achieved if repowering includes modifying the steam cycle for district heating. Many of the large electric generating plants that have been installed in Europe over the last decade feed extensive district-heating networks. While including district heating in a repowering scheme does not lower emissions in an absolute sense, it avoids a separate emissions source and fuel and hardware expenses to generate steam and heat separately. On the other hand, balancing electric and thermal energy flows reduces the operating flexibility. Seasonal differences in electric and thermal demand must be accounted for.

Repowering with diesel engines combines the high efficiency and great fuel flexibility of engines with the economics of existing coal-fired generators. In one scheme, oil-/gas-fired engines exhaust into a coal-fired boiler modified to fire micronized coal. Heat rates in the range of 9000 Btu/kWh have been projected for such cycles. According to promoters, the temperature and O_2 content of diesel engine exhaust are most compatible with traditional boilers. Exhaust acts as preheated combustion air to the burners. Fresh air is added to optimize combustion and achieve stable flames. This plus the reduced gas losses associated with lower O_2 levels lead to higher boiler efficiency.

This scheme required back-end cleanup to achieve respectable emissions levels. However, assuming a back-end cleanup system was installed, it can do double duty, removing pollutants from both the diesel and the Rankine cycle portions of the power plant. This may allow the use of lower-quality, less expensive fuels in the engine. Other potential advantages noted relative to gas turbines are greater flexibility in matching prime mover to existing steam cycle; less impact on performance from ambient temperature or ambient air conditions, especially at coastal sites; less arduous operations and maintenance (O&M) because of the ruggedness of engines compared to gas turbines; and better capability for meeting radically changing thermal and electric loads.

3.8 Summary

Repowering is a cost-effective method of rehabilitating and extending the life of an aging plant. Repowering is also an ideal solution to utilities seeking new capacity and wanting to avoid the costly process, in terms of time and capital, of building a greenfield power plant. In today's fast-paced and increasingly competitive power supply, repowering makes sense as part of a utility's business plan, as well as its capacity plan. As electric utility executives look to improve the profitability of their companies, they must focus on maximizing the output and performance of fossil-fueled power plants. Repowering will become a major part of the strategic plan to achieve this goal.

4.0 EMISSIONS CONTROL

Air pollution in the Czech Republic has been reported to affect the health of 20% of the population (OECD, 1994; Jílek and Novotný, 1994). As a result, emission control regulations in the Czech Republic have become more restrictive since the breakup of the former Soviet Union and the Czech Republic's move toward a market-based economy. Current regulations restrict particulate emissions for new and existing units having a capacity of >50 MWth to 100 mg/Nm^3 (0.074 lb/MMBtu) regardless of fuel source. Sulfur dioxide emissions for new and existing units with a capacity of 50 to 300 MWth and >300 MWth are limited to 1700 mg/Nm^3 (1.26 lb/MMBtu) and 500 mg/Nm^3 (0.37 lb/MMBtu), respectively. The emission of nitrogen species, as NO_2, is restricted to 650 mg/Nm^3 (0.48 lb/MMBtu) for all coal- or lignite-fired units having a capacity of >0.2 MWth. Table 4 summarizes the current Czech Republic emission limits for solid, liquid, and gaseous fuels.

Key factors affecting electrical generating plant operations in central European countries generally include fuel shortages, variable and poor fuel quality (high moisture, ash, and sulfur), furnace slagging, flame impingement, furnace tube failures, high furnace exit temperatures, superheater failures, superheater and reheater overheating, air inleakage, burner area erosion, economizer erosion, induced-draft (ID) fan erosion, poorly performing

TABLE 4

Current Air Emission Limits for Stationary Combustion Sources in the Czech Republic (OECD, 1994; Jílek and Novotný, 1994)[1]
(enforced from November 1991)

	Pollutant	Plant Capacity or Type, MWth	Emissions Limit, mg/Nm^3	lb/MMBtu	Mandatory Performance of FGD Equipment (when FGD is needed to meet SO_2 emissions limit)
Solid Fuels	Particulates	>50	100	0.074	
		5–50	150	0.111	
	SO_2	>300	500	0.37	85% removal
		50–300	1700	1.26	70% removal
		0.2–50	2500	1.85	
	NO_2	>0.2	650	0.48	
		smelters	1100	0.81	
	CO	>0.2	250	0.18	
Liquid Fuels	Particulates	>50	50	0.037	
		0.2–50	100	0.074	
	SO_2	>300	500	0.37	85% removal
		5–300	1700	1.26	
	NO_2	>5	450	0.33	
	CO	>0.2	175	0.13	
Gaseous Fuels	Particulates	>0.2	10	0.007	
	SO_2	>0.2	35	0.026	
	NO_2	>0.2	200	0.147	
	CO	>0.2	100	0.074	

[1] Emission limit basis is dry gas, 101.32 KPa, 0°C, and 6 vol% O_2 for solid fuel (no wood), 11 vol% O_2 for wood, and 3 vol% O_2 for liquid and gaseous fuels.

electrostatic precipitators (ESPs) ($<99\%$ particulate control), and limited turndown capacity. Because fuel shortages and quality may be key issues for some plants, resolution of these issues is important prior to evaluating options for boiler rehabilitation or technology options for reducing particulate, SO_2, and NO_2 emissions. Once the fuel source and characteristics have been identified, boiler rehabilitation and emission control options can be evaluated.

Coal-fired electrical generating capacity operated by utilities and cogenerators totals 9261 MW, representing 64.8% of the total electrical generating capacity in the Czech Republic. At this time, plans call for decommissioning roughly 2300 MW of obsolete lignite-fired capacity and upgrading newer coal- and lignite-fired units representing 6200 MW of capacity for continued service after 1998. Decommissioned lignite-fired capacity will be replaced by new nuclear capacity totaling 2000 MW. Although fuel quality has been a problem, there are no plans for extensive fuel switching. Therefore, unit rehabilitation activities must be based on the continued use of the high-moisture and high-ash lignite.

Sections 4.1 Particulate Control, 4.2 Flue Gas Desulfurization, 4.3 Nitrogen Oxides, and 4.4 Integrated Emissions Control Systems briefly discuss U.S. experience with various emission control technology options. In addition, technology options that may be appropriate for use by the Czech Republic power industry are discussed. U.S. companies that have indicated an interest in conducting business in central Europe and have demonstrated experienced in the design, construction, installation, or operation of these technology options are identified. It cannot be overstated that the general comments made in the following sections are just that, general comments. These comments are based on limited information. Ultimately,any detailed station or unit rehabilitation plans must be based on thorough, detailed technical evaluations of each unit, including the consideration of social and economic constraints specific to the Czech Republic. A key element to controlling the cost of upgrades would be the manufacture of components in the Czech Republic or other Central European countries, where possible.

4.1 Particulate Control

Commercially available technologies such as ESPs and fabric filters have demonstrated their ability to control particulate emissions for a variety of fuel (bituminous and subbituminous coal and lignite) and boiler types around the world. In the United States, both ESPs and fabric filters have been used successfully to control particulate emissions in order to meet the current emission limit, NSPS, of 0.03 lb/MMBtu (40 mg/Nm^3) for units capable of firing >250 MMBtu/hr (>73 MWth) of heat input. This standard also limits opacity to $<20\%$ and applies to units newly constructed or expanded after September 18, 1978. The use of ESPs in the U.S. utility sector has been significantly greater than the use of fabric filters because of their earlier technical development and acceptance for utility applications. Based on U.S. experience, both ESPs and fabric filters should be appropriate technology options for meeting the Czech Republic's particulate emission limits of 100 and 150 mg/Nm^3 (0.074 and 0.111 lb/MMBtu).

4.1.1 Electrostatic Precipitators

The vast majority of present-day U.S. coal-fired systems make use of ESPs for particulate control. Current ESP designs and performance are generally adequate to meet the particulate NSPS, 0.03 lb/MMBtu (40 mg/Nm^3), for a wide variety of boiler designs and fuel types (bituminous coal, subbituminous coal, and lignite). However, ESP performance is highly dependent on flue gas and fly ash composition and sensitive to flue gas flow rates, temperature, and particulate loadings. Although overall ESP particulate collection efficiency can be high, >99%, collection performance is significantly reduced for particles between 0.1 and 1.0 microns in diameter. Reduced collection efficiency for fine particulate is caused by particles of different diameters having different effective migration velocities as well as particle reentrainment resulting from rapping characteristics. Therefore, conventional ESP technology is least effective at controlling fine-particle emissions, the anticipated focus of future U.S. regulations. However, European experience indicates that ESPs can meet more stringent emission standards for certain applications (Porle et al., 1993).

Options for improving ESP performance include design modifications, upgraded power supplies and controls, chemical conditioning, pulse energization, prechargers, wet ESPs, and particle agglomeration, applied individually or in combination. One design modification that can improve particle collection in an ESP is increasing the specific collection area (SCA, ft^2/1000 acfm). However, the cost of an ESP is directly related to its size and is dictated by the design SCA. Therefore, simply increasing the size of an ESP to improve performance is cost-prohibitive; more cost-effective design improvements are necessary.

One ESP design feature that has seen significant improvement over the years has been the discharge electrode design. Early ESP designs in the United States were referred to as a weighted wire type (Miller and Laudal, 1987; Crynack, 1992). A more rugged and reliable design referred to as the rigid frame, originated in Europe and became popular in the United States in the 1970s (Crynack, 1992; Wright and Graves, 1979). In the 1980s, a general electrode design referred to as a rigid discharge electrode became popular and has been implemented by utilities to upgrade ESP performance (Blacet and Arstikaitis, 1993; Kaminskí and Altman, 1993). Several specific discharge electrode geometric designs are all referred to as rigid discharge electrodes. The advantages of improved electrode designs include reduced cost, ease of installation, and improved electrode alignment, rapping characteristics, ESP reliability, and overall performance.

Collection electrode design has also changed over the years, with U.S. designs primarily using shielded flat plates. Early designs made use of narrow plate spacings, while some early work and work completed in the 1970s showed that wider plate spacings result in higher particulate collection efficiencies (Heinrich, 1978; Engelbrecht, 1983; Nichols, 1978; Miska et al., 1978; Matts, 1978). However, wide plate spacings are not appropriate in applications with high inlet particulate loadings consisting of very fine particles, as these conditions can result in high space charges and corona quenching. Electrode spacing is a critical design parameter requiring careful consideration of ESP design characteristics, flue gas composition, and fly ash characteristics in each application. Wider plate spacing has been successfully used in several recent utility ESP upgrades (Blacet and Arstikaitis, 1993; Kaminskí and Altman, 1993; Kohl and Meinders, 1993).

Improvements have also been made to rapping mechanisms and control. In many cases, poor ESP performance has been related directly to problems with the rapping system. Rapping intensity and frequency have a significant effect on overall ESP performance (Oglesby and Nichols, 1977; Andrews et al., 1993; Tumati, 1993). Insufficient rapping intensity and/or frequency can result in inadequate cleaning of collector plates and reduced collection efficiency. Excessive rapping intensity and/or frequency can result in ash reentrainment and reduced efficiency. Increasing the number of rapper locations and reducing rapping intensity, along with application of computer controls to permit adjustments to rapping intensity and frequency for individual fields in an ESP, have contributed significantly to improvements in ESP performance.

The advent of microprocessors to replace analog controllers has significantly improved the performance of high-voltage power supplies and controls for ESPs, resulting in reduced power usage and improved performance (Andrews et al., 1993; Weaver et al., 1992; Artz and Neundorfer, 1992). Microprocessors permit rapid on-line monitoring of ESP operating conditions and permit precise control of power input to the electrodes.

Design and component improvements, such as those described, have contributed significantly in recent years to observed increases in total mass particulate collection efficiency (<99% to >99%). However, these design improvements alone are not adequate to meet the performance requirements necessary for ESPs to control fine particulate emissions effectively and meet the particulate emission limits anticipated in the future.

Chemical conditioning agents are a low-cost option for modifying flue gas and fly ash characteristics in order to improve ESP performance, and work in this area has been ongoing for many years. Chemical conditioning agents have included water, sodium compounds, ammonia, sulfur trioxide (SO_3), and various proprietary compounds (Hilborn, 1993). Ammonia and SO_3 are the most common and successfully used conditioning agents. In the case of ammonia, its relatively low cost, readily available supplies, and simple injection system remain key elements of its continued use. However, ammonia has only been effective as a conditioning agent in limited ESP applications (Dismukes, 1975, 1983; Ferrigan and Roehr, 1993). Use of ammonia as a conditioning agent in ESPs appears to be most beneficial for chemically acidic fly ash. The benefits of ammonia conditioning are believed to include a space charge effect permitting a higher operating voltage, reduced reentrainment as a result of increased ash cohesiveness, and a reduction of stack opacity as a result of vapor-phase reactions preventing the formation of sulfuric acid mist.

By far the most commonly used conditioning agent continues to be SO_3. When injected into the flue gas, SO_3 adsorbs onto the surface of fly ash particles, reducing ash resistivity, effectively reducing back corona, and improving overall ESP performance (Oglesby and Nichols, 1977; Andrews et al., 1993; Hankins and Gorge, 1993). The amount of SO_3 required to achieve the desired effect is usually small (<20 ppm). However, the required amount in any particular application is dependent on fly ash chemistry and flue gas temperature. Fly ash generated as a result of firing coals with high calcium levels in the ash will require larger concentrations of SO_3 to overcome the neutralizing effect of calcium (Dismukes, 1975). Low-sulfur coal applications are the primary commercial use for SO_3 conditioning in ESPs (Dismukes, 1975; Ferrigan and Roehr, 1993). In some cases, SO_3 conditioning is part of the original ESP design strategy for low-sulfur coal applications. In other cases, SO_3 conditioning is a retrofit requirement subsequent to a utility switching from a high- to a low-sulfur coal. In many early cases, the improvement in ESP performance was dramatic, with particulate collection efficiencies increasing from <80% to >90%. In other cases, the effect was less dramatic, with efficiencies increasing from 90%–95% to 95%–99%.

The combined use of ammonia and SO_3, referred to as dual flue gas conditioning, has been successfully tested at the pilot scale and implemented at full scale for certain applications (Fletcher, 1985; Dahlin et al., 1984, 1986; Ferrigan et al., 1992). Dual conditioning is defined as the independent but simultaneous injection of SO_3 and ammonia. Full-scale application of dual conditioning has shown that, for some ashes, the use of ammonia in combination with SO_3 enhances the ability of the SO_3 to reduce resistivity for a given SO_3 concentration. In addition, enhanced ash cohesivity has been observed with dual conditioning, even with high LOI, effectively reducing ash reentrainment. Also, in cases where excess SO_3 in the flue gas resulted in a "blue plume," the addition of ammonia reduced the SO_3 concentration necessary to reduce resistivity effectively and reacted with excess SO_3 to eliminate the blue plume condition.

Recent pilot-scale work using dual conditioning and a range of problematic fuels (lignite, subbituminous coal, and bituminous coal), characterized as having a high ash resistivity requiring some level of SO_3 conditioning to achieve acceptable ESP performance, has indicated some advantages for the dual conditioning approach (Krigmont et al., 1992; Miller et al., 1993). Specifically, ammonia appears to enhance the ability of SO_3 to reduce resistivity and simultaneously increases ash cohesiveness. The desired effect is accomplished using lower concentrations of SO_3 in combination with ammonia than would be required with SO_3 alone. Overall performance results indicate a significant reduction in total mass emissions. More importantly, the data show a significant decrease in fine-particle emissions (<10 microns).

Based on full- and pilot-scale data, a combination of improved ESP design and equipment and the application of flue gas conditioning may be adequate to meet more stringent particulate emission limits in the future for certain fuels. However, the universal application of ESPs to meet future regulations is unlikely, and in the final analysis, technology selections will be based on technical performance and competitive economics. Therefore, the role of ESPs in future industrial and utility markets is unclear.

Pulse energization is another technique for overcoming ESP performance problems relating to high resistivity ashes (Feldman and Aa, 1982; Porle and Bradburn, 1986; Landham et al., 1986; Kumar and Feldman, 1992; Landham et al., 1993; Noguchi and Sakai, 1993). The development of solid-state electronics and inexpensive high-voltage sources made pulse energization a commercial option in the 1970s. Application of a high-voltage pulse, at a relatively constant potential generates a strong uniform corona, reducing excessive sparking and back corona. The overall effect is an improvement in current density and uniformity of distribution. Results from full-scale applications have shown that pulse energization is an effective option for returning an ESP to a performance level consistent with its original design or reducing the size and, effectively, the cost of a new ESP. However, pulse energization is no more effective technically or economically than flue gas conditioning.

Precharging, generally referred to as multistage electrostatic precipitation, is another ESP design option that was conceived many years ago but only became a technical and economical possibility with the advent of solid-state electronics. The concept involves charging particles and collecting particles in separate stages (Tassicker and Schwab, 1977; Masuda, 1984; Cooper et al., 1977; Sparks et al., 1979; Durham et al., 1986; Clements et al., 1986). Separating the stages allows charging fields 3 to 5 times higher than those used in conventional ESPs without sparkover. The concept permits the precharging field to be small, even for large volumetric flue gas flow rates. Various precharger designs are offered by various companies.

Wet ESPs are considered a technical option for collecting material found to be problematic in conventional ESPs (Okuda and Wada, 1984; Stanley, 1980; Kumar and Fledman, 1994; Fujishima and Tsuchiya, 1993). Water is used to clean the collecting plates; resistivity is reduced as a result of saturating the flue gas with moisture; and reentrainment is minimized. The wet ESP has also been observed to control acid mist and fine-particle emissions more effectively. Problem areas include moisture-saturated flue gas, application difficulties for high-SO_2 and dust-loading conditions, the wastewater treatment required, and the potential for material corrosion. However, wet ESPs are being applied commercially to industrial and utility systems.

Particle agglomeration is a concept under development that attempts to modify the size of fly ash particles in order to improve the performance of cyclones, conventional ESPs, and fabric filters. Specifically, individual fine particles (<5 microns) collide and stick together, forming larger particles that are more easily collected. Early work focused on acoustic agglomeration (Shaw and Wegrzyn, 1977; Wegrzyn et al.,1979; Cooper et al., 1976; Reethof and McDaniel, 1983; Faeser and Reethof, 1985; Scott et al., 1977). This concept used high-frequency sound to promote the oscillating motion of particles entrained in the gas stream. Although some technical success was achieved, problems relative to energy consumption, adequate sound insulation to protect operations personnel, and limited performance results at a flue gas mass loading consistent with utility systems were noted. There has been little development work in recent years. The recent focus of development efforts has been on the use of electrostatic charging of particles to promote particle agglomeration. All this work appears to be fairly recent,and development efforts are mostly proprietary. Thus little information has been published.

In order for ESP technology to play a significant role in meeting future U.S. particulate emissions standards, it will be necessary to demonstrate improved fine-particle capture at a cost competitive with other technologies. However, current commercial ESP technology options should be more than adequate to meet the needs of the Czech Republic's coal-fired electrical generating systems.

4.1.2 Fabric Filters

Although one of the oldest methods for removing solid particles from a gas stream, fabric filtration began to play a prominent role in particulate emissions control in the U.S. utility sector only in the early 1970s. Initially, fabric filters were thought to be the answer to the performance problems experienced by ESPs. For many applications, specifically low-sulfur coals generating high-resistivity ashes, fabric filters were found to be a good alternative to ESPs. Full-scale performance results demonstrated particulate control levels ranging from 98% to nearly 99.99% (Barranger, 1986; Dahlin et al., 1984; Southern Research Institute, 1991). Operating differential pressure ranged from 4 to 8 inches W.C. (water column), and typical bag life increased to 3 years since early installations in the 1970s. Baghouse reliability has been excellent, with problems corrected during scheduled outages or in service, resulting in essentially no impact on boiler availability. Fabric filters were also observed to collect fine particles more efficiently than conventional ESP's (Buonicore et al., 1978; Wyss et al., 1980;

Preston, 1986). Specifically, the fractional efficiency for a fabric filter is 99% versus 95% for an ESP for particles ranging in size from 0.1 to 1.0 microns.

However, fabric filters have their own set of disadvantages. These include large space requirements, the application of expensive specialized fabrics for potentially chemically active environments, dust explosion and fire hazards, reduced performance for fine particles (<2.5 microns), and susceptibility to performance limitations (particulate collection efficiency and differential pressure) for problematic ashes. As a result, fabric filtration research has focused on several fundamental areas: dust cake formation, fabric development, pressure drop control, and improving fine particle collection. Even a brief discussion of these topics is not possible in this document; however, a summary of these topics with extensive references was prepared and published by EERC personnel in 1987 (Miller and Laudal, 1987).

Early utility fabric filter installations were low face velocity (<3 ft./min), reverse-gas or shake-deflate units using a woven fiberglass fabric. Based on successful performance in the industrial sector, pulse-jet fabric filters (PJFF) have recently begun to penetrate the utility industry worldwide (Vandewalle and Johnson, 1993; Robertson and Strangert, 1993; Belba et al., 1992; Belba, 1991). The primary advantage for the PJFF is its higher operating face velocity (3 to 6 ft/min) which results in a smaller overall unit that is significantly less expensive to build than the reverse-gas or shake-deflate units. Early concerns with bag life and cleaning system complexity have been resolved to a large degree with the development of more durable fabrics and simpler low-pressure, high-volume cleaning concepts. Particulate collection efficiencies have met the U.S. 0.03 lb/MMBtu NSPS in all cases, with many systems controlling emissions to less than 0.01 lb/MMBtu (14 mg/Nm^3). However, this level of performance may not be adequate to meet the stricter emission limits anticipated in the future.

Pilot-scale tests sponsored by the Electric Power Research Institute (EPRI) have shown that pulse-jet baghouses have broad application to utility systems (Etheridge et al., 1992; Heaphy et al., 1992). A slipstream baghouse operating on a older boiler firing a low-sulfur coal demonstrated particulate collection efficiencies of 99.99%, with an operating differential pressure of 4 inches W.C. Measured outlet emissions were generally <0.002 lb/MMBtu (<3 mg/Nm^3). Results on a high-sulfur application also showed good particulate collection performance, with emissions generally <0.01 lb/MMBtu (<14 mg/Nm^3). However, in this case, bag failures began to occur after 3000 hours of operation. Based on the data from these pilot-scale tests, it appears that PJFFs can successfully control particulate emissions from utility boilers to meet current NSPS standards and, in some cases, may be able to meet the stricter standards anticipated in the future.

Options for improving fabric filter fine-particle performance include design modifications, electrostatically enhanced filtration, chemical conditioning, and particle agglomeration, applied individually or in combination. In a fabric filter, a significant proportion of the emissions results from emission spikes during cleaning cycles. Therefore, any design or operational modification that would reduce cleaning cycle frequency or the resulting emission spike would improve the fine-particle collection efficiency of fabric filters. Another design approach that would improve the fine-particle collection in a fabric filter is to increase the fabric collection area, effectively operating at low face velocities. However, the cost of a fabric filter is directly related to its size. Therefore, simply increasing the size of the fabric filter to improve performance is cost-prohibitive; more cost-effective design options are necessary.

Development of electrostatically enhanced fabric filters has been ongoing for more than 20 years (Donovan, 1985; Viner et al., 1986; Humphries et al., 1984; Crask and Applewhite, 1983; Felix and McCain, 1979; Greiner and et al., 1981; Chambers et al., 1986; Hovis and Viner, 1986; Helfritch, 1992). Results indicate that for some design variations, both particulate emissions and differential pressure can be significantly reduced, cost-effectively. However, high ash resistivity can be problematic, and power consumption in some cases can be significant. Commercial implementation of electrostatically enhanced fabric filters has not occurred because of the perceived complexity of a combined fabric filter and high-voltage components and the absence of a need for a technology capable of meeting performance goals beyond those possible with conventional fabric filtration. However, the recent interest in fine-particle emissions (<2.5 microns), air toxics, and the anticipation of more restrictive particulate emission regulations may motivate commercial development of electrostatically enhanced fabric filters.

Flue gas conditioning, as applied to fabric filters, has seen continued development success since the early 1980s (Felix et al., 1986; Miller and Laudal, 1985; Laudal and Miller, 1986, 1987; Miller, 1989). Early work on a full-scale utility baghouse demonstrated that ammonia conditioning improved particulate collection efficiency from <98% to >99.9% on a total mass basis, but no fractional efficiency data were reported. Early pilot-scale data showed that using a combination of SO_3 and ammonia can be effective in reducing fine particulate emissions as well as total emissions by several orders of magnitude. In addition, operating pressure drop was reduced by 30% to 75%. The basis for improved performance is an increase in the cohesive strength of the dust cake, which reduces particle penetration but simultaneously increases the porosity of the dust cake, minimizing differential pressure.

A recent pilot-scale study on pulse-jet baghouse applications has shown that flue gas conditioning with SO_3 and ammonia can increase particulate collection efficiency to levels ranging from 99.95% to 99.99% (Miller and Laudal, 1992). This work was completed using a range of coals and filter face velocities (4 to 16 ft/min). The operating differential pressure was also reduced in each case. These results indicate the potential for meeting a stricter emission standard using a PJFF in combination with dual flue gas conditioning. The results also imply that current emission standards can be met using smaller fabric filters operating at higher face velocities.

Bench- and laboratory-scale tests evaluating alternative conditioning agents have been completed, indicating a significant reduction in the level of particulate emissions comparable to those observed with SO_3 and ammonia (Durham et al., 1994). Further development work will attempt to confirm these results at the pilot and full scale in an effort to identify a cost-effective alternative to SO_3 and ammonia.

The performance of fabric filters could also be improved by the successful application of particle agglomeration techniques. As stated previously in reference to ESP applications, particle agglomeration is an attempt to create one large ash particle from several small ash particles. Although fabric filters are generally better collectors of fine particulate than ESPs, a reduction in the quantity of fine particulate as a result of particle agglomeration would also benefit fabric filter performance.

In order for fabric filter technology to play a significant role in meeting future U.S. particulate emission standards, improved fine-particle capture at a cost competitive with other technologies must be demonstrated. However, current commercial fabric filter technology options should be more than adequate to meet the particulate emission control objectives of the Czech Republic's coal-fired electrical generating systems.

4.1.3 Options for the Czech Republics' Power Industry

Although specific particulate emissions data were not available, this evaluation assumes that current actual particulate emissions from many coal- and lignite-fired units exceed the 100 mg/Nm^3 (0.074 lb/MMBtu) emission limit established for all new and existing units having a capacity of >50 MWth. Since both ESPs and fabric filters have demonstrated the ability to meet the U.S. particulate emissions limit of 0.03 lb/MMBtu (40 mg/Nm^3), both of these technology options should be capable of meeting the Czech Republic particulate emission limits. The key to successfully implementing cost-effective equipment or procedural changes to meet the desired particulate emission limit on existing units will be to evaluate particulate control upgrade options in combination with any other unit or stationwide changes planned. For example, plans for fuel switching and boiler upgrades must be factored into the particulate control evaluation process in order to effectively control cost and meet emission control objectives. For new units, the selection of particulate control technology should be factored into the bid process for an overall unit, with economics, performance, and reliability motivating the decision process. Since the scope of this study and the amount of information available concerning the status and condition of the existing units in the Czech Republic were limited, it was not possible or appropriate to discuss equipment or procedural upgrade options in detail. Therefore, the intent is to briefly describe a range of technology upgrade options and identify U.S. companies that have shown an interest in projects in central Europe and have demonstrated experience relative to the applicable technology options.

Since ESP technology has been extensively applied in Czech Republic power stations to control particulate emissions, the first step must be to evaluate options for upgrading the existing ESPs prior to considering the application of alternative technologies. For units that are scheduled for decommissioning or repowering with natural gas, there is no need to consider particulate upgrade options. In the case of repowering coal- or lignite-fired units, ESP upgrades may be appropriate. However, where repowering will involve the use of FBC technology, a PJFF may be the least-cost particulate control option. Also, in cases where a spray dryer absorber (SDA) is recommended for SO_2 control, particulate control is accomplished in a downstream fabric filter, negating the need for ESP upgrades. Table 5 presents a list of and identifies a point of contact for U.S. companies that have indicated an interest in providing information concerning particulate control technology options appropriate for the Central European power industry.

Because fuel shortages and quality are key issues for some plants, resolution of these issues are important prior to evaluating options for boiler rehabilitation or equipment upgrades for improving particulate control. Once the fuel source and characteristics have been identified and boiler rehabilitation options have been selected, ESP upgrade options can be evaluated.

TABLE 5

U.S. Companies That Have Expressed Interest in Particulate
Control Technology Projects in Central Europe

ABB Environmental Systems
31 Inverness Center Parkway
Birmingham, Alabama 35242
Mr. Paul Yosick
Director of Marketing
Phone (205) 995-5321
Fax (205) 995-5496

Black & Veatch
11401 Lamar Avenue
Overland Park, Kansas 66211
Mr. Leroy E. Kashka
Project Manager
Phone (913) 339-2431
Fax (913) 339-2934

Raytheon Engineers & Constructors
PO Box 5888
Denver, Colorado 80217
Mr. Paul A. Ireland
Chief Engineer, Air Pollution Control
Phone (303) 843-3420
Fax (303) 843-2358

Burns & McDonnell
4800 East 63rd Street
Kansas City, Missouri 64130
Mr. John P. Werthman, P.E.
Manager, Business Development
Air Pollution Control Division
Phone (816) 822-3437
Fax (816) 822-3415

Environmental Elements Corporation
3700 Koppers Street
PO Box 1318
Baltimore, Maryland 21203
Mr. Hamilton G. Walker, Jr.
Manager, International Business
Phone (410) 368-7046
Fax (410) 368-6721

Sargent & Lundy Engineers
55 East Monroe Street
Chicago, Illinois 60603-5780
Mr. William DePriest
Manager, Air Quality Control Services
Phone (312) 269-6678
Fax (312) 269-3634

U.S. companies generally suggest that existing ESPs may be adequate if the fuel source selected is not poor quality and/or appropriate improvements are made to the boiler/combustion systems. A more thorough upgrade of the ESPs on newer units is recommended as a result of a longer anticipated operating life. Also, units firing poor quality fuel, such as the lignite-fired units in the Czech Republic, may require more thorough upgrades in order to achieve the established particulate emission limit. In some cases, the replacement of ESP internals (plates and electrodes) with U.S. designs may be economical if it is necessary to repair structural internals in order to extend life. Also, ESP performance could be improved relative to reduced emissions and increased reliability by simply installing new transformers, rapping system, and controls. In many cases ESPs can be successfully upgraded for half the cost of installing new ESPs or alternative technology such as fabric filters. One approach successfully used in Central Europe involves adding 30% to 40% more collection area and increasing electrical sectionalization in the existing casing without impacting the plan area or ID fan. This has been accomplished by reducing between field access and increasing the height of the ESP but allowing for the reuse of existing support steel and the ash hoppers and handling system. Modifications to the inlet and outlet ductwork are also generally necessary to assure proper gas distribution,and careful consideration must be given to material corrosion issues for high-moisture fuels. In units where low-sulfur fuels are fired, flue gas conditioning may be necessary to achieve the desired ESP performance.

Improvements in particulate control would also be augmented by the addition of wet scrubbers or another flue gas SO_2 control technology selected as part of an overall emissions control package. However, adequate ESP performance would be required in order to avoid scrubber chemistry and operability problems. Also, the use of an advanced SO_2 control process producing a salable by-product may require better overall particulate control. An example would be an ammonium sulfate by-product to be used as a fertilizer in agricultural applications. Better particulate control may be necessary to limit the concentration of heavy metals, boron, and other compounds in the fertilizer depending on local regulations. If improved ESP performance is required to limit the quantity of heavy metals, boron, or other compounds reaching the scrubber, increasing the ESP specific collection area may be adequate. Another option would be to install a high face velocity pulse-jet baghouse downstream of the ESP using the COHPAC concept. If a dry system, such as an SDA or Lurgi CFB were used for particulate and SO_2 control, a new ESP or PJFF would be required. A new ESP, preferred for Lurgi CFB technology, would require a specific collection area of >500 ft^2/acfm.

4.2 Flue Gas Desulfurization

Present NSPS for U.S. utility coal-fired boilers limit sulfur dioxide (SO_2) emissions to a maximum of 1.2 lb/MMBtu (1620 mg/Nm^3) and require a minimum of 70% to 90% SO_2 control, depending on potential SO_2 emissions. This limit applies to facilities newly constructed or expanded after September 18, 1978, having an input firing rate of >250 MMBtu/hr (>73 MWth). The Clean Air Act Amendments of 1990 require 111 older uncontrolled utility stations to reduce SO_2 emissions to 2.5 lb/MMBtu (3380 mg/Nm^3) in 1995, and all plants must meet a 1.2 lb/MMBtu (1620 mg/Nm^3) emission limit by the year 2000. More importantly, in the year 2000, all existing and new utility plants will be restricted to a combined emissions cap of 8.9 million tons of SO_2 annually. As a result, new units will have to obtain SO_2 allowances from the control or decommissioning of older units. Therefore, recent regulatory activities have provided a significant incentive for the development of highly efficient, cost-effective technology options for meeting these U.S. emission standards.

Commercially available FGD technologies such as SDAs and wet limestone scrubbers (WLS) have demonstrated their ability to control SO_2 emissions for a variety of fuel (bituminous and subbituminous coal and lignite) and boiler types around the world. In the United States, both SDA and WLS have been used successfully to control SO_2 emissions in order to meet the NSPS for SO_2. As a general rule, SDA have been used for low- sulfur fuel applications with SO_2 control requirements of up to 85%, and WLS have been used for applications requiring >85% SO_2 control. However, WLS have also been used for low-sulfur fuel applications, and recent studies have evaluated the use of SDA for high-sulfur fuel applications requiring 90% SO_2 control. Based on U.S. experience, both SDA and WLS should be appropriate technology options for meeting the Czech Republic SO_2 emissions limits of 500 and 1700 mg/Nm^3 (0.37 and 1.26 lb/MMBtu).

4.2.1 U.S. Experience

Coal- and lignite-fired electrical generating units in the United States, subject to the NSPS for SO_2, have relied on conventional wet or dry scrubbing technology to meet emission limits. In anticipation of acid rain legislation, several low-capital-cost retrofit technologies were developed and demonstrated. These low-capital-cost retrofit technologies generally included some form of furnace or duct injection using various types of calcium- and/or sodium-based sorbents with flue gas humidification. Although these retrofit concepts were low-capital-cost options, they were found to impact system performance to varying degrees, had limited SO_2 control potential, generated large quantities of solid waste for disposal or limited reuse applications, and did not adequately anticipate the market-based emissions control/trading program permitted by the Clean Air Act Amendments of 1990. As a result, of the 261 units (89,545 MW) affected by Phase I requirements, only 25 units (13,500 MW) opted for the use of emissions control technology to meet the 2.5 lb/MMBtu (3380 mg/Nm^3) limit (Keeth et al., 1995). Limestone forced-oxidation (LSFO) units represented the majority of the new systems, with a few magnesium-lime units also selected. The average cost for these retrofits was reported to be about US\$231/kW with a range of US\$120 to US\$348/kW. Fewer spares, larger absorbers, vendor competition, and low interest rates were identified as key cost factors. Roughly 62% (>50,000 MW) of the Phase I units elected to switch or blend fuels to meet the SO_2 limit. Emission allowance trading as a result of over control and unit retirement were used to meet requirements for the remaining units.

Papers were recently presented documenting the successful completion of seven Phase I FGD retrofit projects (Conn et al., 1995; Buckner et al., 1995; Walsh and Cirillo, 1995; Wiggins et al., 1995; Ruppert and Mitchell, 1995; Peterson et al., 1995; Altin et al., 1995). In all cases, SO_2 removal was >90%, with a few >95%. LSFO was selected for five of the seven retrofits, with commercial-grade gypsum produced as a by-product in three of the five units and gypsum stacking applied in two cases. Two of the LSFO units included the use of acid additives to increase SO_2 removal to levels >95%. Wet, magnesium-enhanced, lime scrubbing was employed in one case representing 1920 MW with an SO_2 removal guarantee of 98%. The seventh project applied a wet limestone, inhibited oxidation system, using an emulsified sulfur solution, to a 650-MW unit. Performance tests demonstrated SO_2 removal efficiencies of 92% to >95% using two absorber modules.

Although SDAs have been successfully applied to utility applications in the United States, variations on WLS systems have dominated past as well as recent technology selections for SO_2 control. In the U.S. utility industry, SDA installations have been limited to low-sulfur subbituminous coal- and lignite-fired units. However, in recent years, conventional SDAs and technical variations have been evaluated for medium- and high-sulfur coal applications (Blythe et al., 1993; Withum et al., 1995; Burnett et al., 1995). Pilot-scale SDA tests sponsored by EPRI and others have demonstrated that a conventional SDA/PJFF can achieve SO_2 removal of 95% and greater. Key factors influencing performance include lime type, flue gas inlet temperature, SO_2 concentration, and chloride concentration. Variations on SDA technology have also demonstrated >90% SO_2 removal during subscale demonstration efforts. In response to Phase I SO_2 control requirements, SDA technology was not selected for any of the retrofit projects reported in the literature. There appears to be an industry consensus that the future installation of SDAs in the United States will be limited to smaller industrial coal-fired units and municipal waste combustion systems.

Babcock & Wilcox Company recently reported results from a 5-MWe pilot-scale test evaluating the potential use of two dry scrubbing concepts for medium-to-high sulfur coal applications (Amrhein and Martinelli, 1995). The first concept, referred to as advanced dry scrubbing, requires careful attention to absorber and atomizer design and slurry feed in order to achieve deposition-free operation of the absorber and reliable baghouse performance at an approach-to-saturation temperature of 10°F rather than 30°F or greater, which is more typical for utility SDA systems. Another key element is the use of a patented droplet impingement device to control the location at which deposition occurs when operating at a low approach-to-saturation temperature. Sulfur dioxide removal for the advanced dry scrubbing concept was reported to be >95% at a 10°F approach temperature and a Ca/S mole ratio of 1.15. The second concept, referred to as limestone injection dry scrubbing (LIDS), combines furnace injection of limestone with a SDA. Sulfur dioxide removal occurs in three locations: in the furnace, the SDA, and the baghouse. The lime source for the SDA is recycle solids collected in the baghouse, eliminating the need for pebble lime. Factors requiring careful attention are the furnace temperature at the point of limestone injection, the amount of limestone injected into the furnace (Ca/S), and the approach-to-saturation temperature in the SDA and baghouse. Sulfur dioxide removal for the LIDS concept was reported to be >95% at a 10°F approach temperature and a Ca/S mole ratio of 1.44. An economic evaluation of the two concepts indicates that the economics are favorable for smaller units (<300 MW) requiring 90% SO_2 control when compared to conventional wet FGD systems. Based on these results, Babcock & Wilcox Company intends to further evaluate the performance of these concepts at the 10-MW scale.

Pilot-scale studies sponsored by EPRI and others evaluated the use of organic acid additives to improve wet scrubber performance (Stevens et al., 1993). Results indicated that the use of an organic acid additive along with a reduction in the liquid-to-gas (L/G) ratio was a cost-effective method of increasing the performance of an existing scrubber from 85% to 95% SO_2 control. Field tests, sponsored by DOE Pittsburgh Energy Technology Center (PETC), have shown that the use of organic acid additives is capable of improving scrubber performance from 85%-90% to 95%-98% SO_2 removal (Blythe et al., 1993; Smolenski et al., 1993; Reynolds et al., 1993; Blythe et al., 1993; Gray et al., 1995; Philips et al., 1995). Incremental costs for the additional SO_2 removal were estimated to be US$30 to US$150/ton depending on the baseline performance of the scrubber system, the specific additive used (dibasic acid or sodium formate), and implementation of other process changes such as increasing or decreasing the L/G ratio.

Other related retrofit efforts addressed mechanical scrubber changes as well as chemical process changes. Indianapolis Power & Light elected to replace the internal packing in one of three modules of a dual-loop FGD absorber with a patented sieve tray (Wolsiffer et al., 1995). Results showed that SO_2 control with the sieve tray was comparable to the internal packing (90%-97% versus 86%-96%). However, a significant reduction in maintenance costs would be realized with the sieve tray as a result of avoiding frequent packing cleaning and replacement requirements. Limited testing with a dibasic acid additive increased average SO_2 removal in the sieve tray module to >98%. Based on these results, sieve trays will be installed in the two parallel absorber modules. Louisville Gas and Electric recently completed a full-scale evaluation of options for reducing operating costs for a dual alkali FGD system at the Cane Run Station (Colley et al., 1995). Results indicated that steps taken to reduce sulfite oxidation, increase lime utilization, improve sulfite regeneration, and improve filter cake wash would result in an annual reduction in operating costs of US$350,000. Other potential cost reduction options being considered include conversion to a magnesium enhanced-lime slurry process or a sodium–lime slurry process. In an effort to identify a low-cost option for reducing SO_2 emissions from 1.2 to 0.85 lb/MMBtu (1620 to 1150 mg/Nm^3), Texas Municipal Power Agency compared the effectiveness of a dibasic acid additive to its inhibited oxidation limestone scrubber at the Gibbons Creek Station with a switch to a magnesium enhanced-lime slurry process (Azam et al., 1995). Results from the tests indicated that the 0.85 lb/MMBtu (1150 mg/Nm^3) SO_2 emission limit can be met more cost-effectively at the Gibbons Creek Station by implementing the magnesium enhanced-lime slurry process.

The U.S. DOE Clean Coal Demonstration Program has a number of projects addressing SO_2 control technology development. Although several projects have involved low-capital-cost retrofit options with limited SO_2 control potential, the program has a few projects addressing high-efficiency SO_2 control technology development. A project being carried out by Pure Air is demonstrating the performance of a single-module limestone scrubber producing a wallboard-grade gypsum by-product (Vymazal et al., 1993; Manavi et al., 1995). Scrubber performance has been excellent, demonstrating an SO_2 removal rate in excess of 95% and an availability rate of 99.99%. A second Clean Coal Demonstration project evaluated the performance of a technology referred to as SNOX (Steen et al., 1993; Borio and Chambers, 1995). This project, carried out by ABB Environmental Systems, is a combined SO_2 and NO_x control technology. Nitrogen species are controlled using SCR, and the SO_2 is oxidized to SO_3 and recovered as sulfuric acid in a condensing heat exchanger. System performance demonstrated SO_2 and NO_x control exceeding 95%. An economic analysis of a 385-MW plant compared the SNOX process with a wet LSFO/SCR system with particulate control accomplished using an ESP in both scenarios. Estimated capital costs were reported to be US$235/kW for the SNOX process versus US$266/kW for the LSFO/SCR system, with levelized costs of 5.51 versus 7.02 mills/kWh, respectively. A third demonstration project evaluated the performance of the Chiyoda Thoroughbred (CT-121) scrubbing process (Burford et al., 1993; Burford and Pearl, 1995). Results demonstrated 95% and 98%–99% SO_2 removal for high- and medium-sulfur coals, respectively. With the ESP on-line, particulate emissions were 0.01 lb/MMBtu (14 mg/Nm^3), and scrubber availability was 98%. Deenergizing the ESP increased particulate emissions to 0.04–0.05 lb/MMBtu (55–68 mg/Nm^3), and scrubber availability was reduced to 95% because of scrubber plugging caused by high fly ash loadings. Ongoing efforts will evaluate the gypsum by-product for utilization in agricultural and construction applications.

In the United States, there is an ongoing effort to develop and demonstrate high-efficiency, cost-effective SO_2 control technologies (Blythe et al., 1993; Heaphy et al., 1993; Strangway et al., 1993; Tung and Keeth, 1993; Withum et al., 1993; Saleem et al., 1993). Although all of these development or demonstration efforts have or anticipate demonstrating $>90\%$ SO_2 control, only a few have, as an objective, an SO_2 control level of $>95\%$. Recent published papers identified a condensing heat-exchanger concept developed by Babcock & Wilcox Company and others, a clear liquor limestone scrubbing concept developed by EPRI, an ammonia-scrubbing system offered by GE Environmental Services, Inc., a magnesium-enhanced lime-scrubbing process developed by Dravo Lime Company, and an advanced limestone wet FGD process developed by ABB Environmental Systems.

Babcock & Wilcox Company, Consolidated Edison Company of New York, and Condensing Heat Exchanger Company have teamed up to develop and demonstrate a condensing heat exchanger to control SO_2, SO_3, particulates, and trace element emissions (Heaphy et al., 1995). The multistage concept makes use of Teflon-coated nickel/copper alloy heat-exchanger tubes in combination with a sodium bicarbonate reagent injection system. Initial tests with a 1.4% sulfur bituminous coal demonstrated 97% SO_2 removal. Residual oil, Orimulsion, and lignite tests resulted in SO_2 removal values of >98%, >94%, and >97%, respectively. Based on these initial results, Babcock & Wilcox Company intends to focus on demonstrating >95% SO_2 removal for coal-fired applications in order to develop a viable alternative to conventional particulate control and scrubbing technologies.

EPRI is currently developing a limestone clear liquor scrubbing system producing a gypsum by-product (Hargrove et al., 1995). Initial pilot-scale results and preliminary economic analysis indicate that 95% SO_2 removal is possible at a levelized cost savings of 19% when compared to a limestone slurry process and 13% when compared to a limestone and dibasic acid slurry process. EPRI cautioned that these results were very preliminary. However, further cost reductions may be identified as other benefits are documented. These may include reduced material abrasion, improved mist eliminator performance, and, higher absorber gas velocities.

GE Environmental Services, Inc., is currently installing a first-of-a-kind, in situ, forced-oxidation, ammonia-scrubbing system that will produce a marketable ammonium sulfate by-product (Brown et al., 1995). The 300-MWe unit will control SO_2 emissions from three steam-generating boilers operated by Dakota Gasification Company at the Great Plains Synfuels facility located in central North Dakota. The ammonia-scrubbing system was selected by Dakota Gasification Company over conventional limestone technology after completion of an on-site pilot-scale demonstration. The process makes use of a countercurrent prescrubber and a recirculating spray of ammonium sulfate slurry to reduce gas temperature, saturate the flue gas, and produce ammonium sulfate crystals as a result of water evaporation. Mist eliminators remove entrained slurry prior to the flue gas entering the countercurrent absorber where the flue gas is contacted with a recirculating subsaturated ammonium sulfate liquor and ammonia injected with the oxidation air. A final set of mist eliminators prevents slurry carryover from the absorber. Ammonium sulfate crystals are removed from the prescrubber and processed through various dewatering and compaction steps to form an ammonium sulfate flake product. Construction of the ammonium sulfate system is scheduled for completion in mid-1996. Performance guarantees stipulate 93% SO_2 removal, 99.5% ammonium sulfate purity, and 97% availability. A key economic factor in the selection of the ammonium sulfate process was an estimated product value of $100/ton for agricultural applications versus an ammonia reagent cost nearly 6 times the cost of limestone used for a conventional FGD system.

Dravo Lime Company has developed a magnesium-enhanced lime FGD process referred to as ThioClear (Lani et al., 1995). This ex situ forced oxidation process produces wallboard-grade gypsum and magnesium hydroxide as by-products. Pilot-scale results have demonstrated 98% SO_2 removal in both a vertical spray tower and a horizontal absorber. Preliminary economics indicate that the ThioClear process can result in a 25% capital cost savings and a 15% levelized cost savings when compared to an LSFO process. However, plans for further testing and demonstration activities were not discussed.

ABB Environmental Systems is marketing a new-generation FGD system referred to as the LS-2 system (Klingspor and Bresowar, 1995). The concept uses open spray tower technology with higher tower gas velocity (above 15 ft/sec), enhanced compact nozzle arrangement, and fine limestone grind (99.5% <44 μm) to produce a wallboard grade-gypsum by-product. Greater than 90% SO_2 removal and 98% limestone utilization were reported. The cost saving for the LS-2 system was reported to be 15% to 30% when compared to conventional FGD systems, making the concept competitive with fuel switching. The first commercial installation of the LS-2 system in the United States is scheduled to start up in mid-1995 on a 130-MW unit at the Niles Station of Ohio Edison Company.

A number of technology development efforts are focused on the simultaneous control of SO_2 and NO_x (Roberts, 1993; Denker, 1993; Gottschlich et al., 1993; Gordon, 1993; Woods et al., 1993; Black et al., 1993; Zamansky et al., 1993; Gangwal and Silveston., 1993). Again, in these development efforts, only a few projects anticipate achieving SO_2 control levels of >95%. Several of these simultaneous SO_2/NO_x control technologies are discussed in Section 4.4, Integrated Emissions Control Systems.

4.2.2 Options for the Czech Republic Power Industry

Although no information was available concerning the range of SO_2 emissions from the various electrical generating units in the Czech Republic, 1990 SO_2 emissions for electrical and district heating units were reported to be 955,778 metric tons, with total SO_2 emissions from all sources of 1,876,000 metric tons (OECD, 1994; Jílek and Novotný, 1994; Vejvoda, 1995). By 1992, total annual SO_2 emissions were reduced to 1,538,000 metric tons. Also, based on fuel analysis discussed previously in this document, theoretical uncontrolled SO_2 emissions were estimated to range from 3380 to >16,220 mg/Nm^3 (2.5 to >12.0 lb/MMBtu). Therefore, this evaluation assumes that actual uncontrolled SO_2 emissions from coal- and lignite-fired units exceed the 500 and 1700 mg/Nm^3 (0.37 and 1.26 lb/MMBtu) standards for units having capacities of >300 MWth and 50 to 300 MWth, respectively. Based on these emission estimates, current SO_2 emissions must be reduced by as little as 50% to more than 97% in order to meet the imposed limits.

One key to successfully implementing cost-effective technology to meet the SO_2 emission limits will be to evaluate SO_2 control options in combination with any other unit- or stationwide changes planned. For example, plans for fuel switching, boiler upgrades, and particulate control upgrades must be factored into the SO_2 control evaluation process in order to effectively control cost and meet emission limit objectives. For new units, the selection of SO_2 control technology should be factored into the bid process for the overall unit, with economics, performance, and reliability motivating the decision process. Since the scope of this study was limited and no information was available concerning the status and condition of the existing units and their layout, it was not possible or appropriate to discuss technology or equipment options in detail. Therefore, the intent is to briefly describe a range of technology options and identify U.S. companies that have shown an interest in projects in Central Europe and have demonstrated experience relative to the applicable technology options.

The application of SO_2 control technology to power stations and district heating facilities in the Czech Republic had not been considered until recently, in response to documented ecological damage and health effects and changes in the regional political and economic philosophy, resulting in the implementation of emission regulations in 1991 and 1992. One of the first steps taken was the identification of specific stations and units at which reducing emissions was a priority. In 1992, the Czech Republic identified eight stations, representing 37 units and 5890 MW, targeted for emissions reduction and repowering projects to be completed between the years 1994 and 2000 (Vejvoda, 1995; Energy and Environment: Least-Cost Coal Utilization, 1992; Czech Republic Ministry of Industry and Trade, 1994; Gavor and Štěpán, 1994; Kašparů and Ullmann, 1994; Kindl, 1995). The stations identified included Tušimice 2 (4 × 200 MW), Prunéřov 1 (6 × 110 MW), Prunéřov 2 (5 × 210 MW), Počerady (6 × 200), Ledvice (4 × 110 and 1 × 200), Chvaletice (4 × 200), Tisová 2 (3 × 100), and Mělník 2 (4 × 110). Initial plans called for evaluating fuel switching, WLS on thirty-one units representing 5740 MW, and repowering as many as nine units with AFBC technology representing 705 MW, with plans for the remaining units not identified. Specific plans reported in late 1994 call for decommissioning units totaling 2405 MW at ten stations; repowering as many as nine units with AFBC technology, representing 705 MW, and installing FGD on thirty-one units, representing 5740 MW. Two units at the Tisová Station, one unit at the Ledvice Station, and the three pulverized coal-fired boilers at the Hodonín and Poříčí Stations are being repowered with AFBCs, with individual unit start-up scheduled for 1995 through 1997. Wet limestone FGD systems were scheduled for start-up on two units at the Počerady Station in 1994, with contracts signed for three additional units for start-up in 1996. Wet limestone FGD systems are scheduled for start-up on four units at the Prunéřov 1 Station and five units at the Prunéřov 2 Station in 1996. Wet FGD contracts were signed in 1994 for the Tušimice 2 Station (four units, 800 MW), with start-up scheduled for 1997. Selection of suppliers is ongoing for FGD installations at the Chvaletice Station (three units, 600 MW), Mělník Station (three units, 720 MW), Detmarovice Station (four units, 800 MW), and the Tisová Station (one unit, 110 MW). Although wet limestone FGD has dominated the retrofit projects to-date, SDAs were selected for two units at the Ledvice Station, with start-up scheduled for 1996.

Long-term objectives, for beyond the year 2000, identified PFBC and IGCC technologies as options for meeting electrical demand in the Czech Republic. Plans for demonstration of combined-cycle pressurized fluid-bed gasification units, with government support, at the Třebovice Station (Mazáč et al., 1995) have been cancelled.

In order to achieve the emission reduction objectives, the first step must be to establish viable technology retrofit options for reducing SO_2 emissions prior to considering detailed evaluations of the alternative technologies. In cases where individual units or entire stations are to be repowered using AFBCs, SO_2 emissions from AFBCs would be expected to meet the 500 or 1700 mg/Nm^3 (0.37 or 1.26 lb/MMBtu) SO_2 limit. Repowering using gas-fired boilers may also be an appropriate option for some aging units because of the poor quality of the available domestic lignite. If gas-fired boilers were selected, no SO_2 control would be required. In all cases, consideration must be given to unit size, age, condition, and anticipated future operating life and load management. If SO_2 emissions trading were an option on a systemwide basis, it should be one of the options factored into the emissions control evaluation process for each unit and station. In general, SO_2 emissions trading will play a greater role for older units having fewer years of service remaining, for load-following units, and for units requiring less SO_2 control to meet a given emissions limit.

In cases where a fuel shortage or quality problem exists, fuel switching and/or blending may be a viable option. In addition to solving fuel problems, switching to a low-sulfur fuel or fuel blend can be the most cost-effective approach to meeting SO_2 emission limits. However, for units with marginally performing ESPs, switching to a low-sulfur fuel or fuel blend can affect ESP performance. As a result, significant ESP upgrades and the use of SO_3 conditioning may be necessary to meet particulate control requirements.

Because of the high-sulfur content of the fuels being fired in the Czech Republic to produce electricity and for district heating and the level of SO_2 control (50% to >97%) required to meet emission limits, low-capital-cost retrofit technologies such as furnace injection or duct injection would generally be inappropriate because of their limited SO_2 control capability and inherent impacts on ESP performance. Also, a wet FGD/fly ash scrubber does not appear to be an appropriate technical and economic option based on the low ash alkalinity indicated in the available fuel analysis. In cases where <70% SO_2 control may be required on a small unit, it may be more cost-effective to overcontrol SO_2 emissions on a few units using a single SDA or WLS module rather than control emissions from all units using a less efficient technical approach.

For small units (50 to 200 MW) requiring 70% to 80% SO_2 capture, lower-capital-cost process options warrant consideration. One example might involve ducting multiple units to a single SDA module, assuming the station layout is conducive to this approach. A circulating fluid bed scrubber may be a technical/economical alternative to an SDA. In either case, downstream particulate control requirements would eliminate the need for ESP upgrades.

Small and large units (50 to >300 MW) requiring >80% SO_2 control will generally require the use of WLS technology in order to meet emission limits. Again, ducting small multiple units to a single WLS module would minimize the cost of the WLS system, depending on station layout. The WLS dewatered gypsum by-product could be handled by either stacking, ponding, or landfilling. Capital costs could be minimized in a forced oxidation system by ponding the waste product. Because of the typical age of the units in the Czech Republic, a very low-cost FGD system is required. However, in cases requiring >80% SO_2 control, lower-capital-cost technology options such as sorbent injection, circulating fluid bed FGD, and SDA would most likely be inappropriate because of the low ash alkalinity and high uncontrolled SO_2 emissions. If switching to a lower sulfur fuel or fuel blend were an option, lower-capital-cost technology options such as SDA or circulating fluid-bed FGD may be appropriate. Alternative technology options may be considered where a salable by-product is produced rather than solid waste for disposal, resulting in lower operating costs. However, the trade-off is higher capital costs.

Larger units (>200 MW) with >15 years of operating life remaining and requiring >80% SO_2 control will require the installation of conventional FGD technology. An SDA may be appropriate in some cases for 80% to 90% SO_2 control. In cases where a SDA were selected for SO_2 control, ESP upgrades would not be necessary since particulate control requirements would be accomplished in the combined absorber/fabric filter system. However, in order to achieve >90% SO_2 control, WLS or some variation will be required. Alternative technology options may be considered where a salable by-product is produced rather than a solid waste for disposal. These high-capital-cost/lower-operating-cost technology options are economically suited for installation on units having a remaining life of >20 years, a high capacity factor, and high flue gas SO_2 concentration. An example would be a wet ammonium sulfate process. The primary attraction of the wet ammonium sulfate process is the production of a fertilizer (ammonium sulfate), valued at roughly US$100/ton, resulting in a positive annual operating revenue stream rather than an operating cost. Concept disadvantages that must be considered include the risk associated with the use of a newer process and the higher capital cost when compared to other technology options. If plant layouts permit, a single absorber module could be installed to treat flue gas generated by multiple units. This approach would minimize capital cost by limiting the number of required modules.

Table 6 presents a list of and identifies a point of contact for U.S. companies that have shown an interest in Central European projects and have demonstrated experience concerning SO_2 control technology options appropriate for the Czech Republic power industry. It cannot be overstated that the general comments made concerning technology options for reducing SO_2 emissions are just that, general comments. These comments are based on limited information. Ultimately, any detailed station or unit rehabilitation plans must be based on thorough, detailed technical evaluations of each unit, including the consideration of social and economic constraints specific to the Czech Republic. A key element to minimizing the cost of SO_2 control technology options would be the manufacture of components in the Czech Republic or other central European countries where possible.

4.3 Nitrogen Oxides

Present NSPS for U.S. utility solid fossil fuel-fired boilers limit the emission of nitrogen species, reported as nitrogen dioxide (NO_2), to a maximum of 0.60 to 0.80 lb/MMBtu (810 to 1080 mg/Nm^3), depending on the fuel and furnace type. The NO_2 limit is 0.70 lb/MMBtu (945 mg/Nm^3) for solid fossil fuels except for lignite. The NO_2 limit for lignite-fired units is 0.60 lb/MMBtu (810 mg/Nm^3) except for cyclone units firing lignites from the Great Plains region of the United States where the limit is 0.80 lb/MMBtu (1080 mg/Nm^3). These limits apply to facilities newly constructed or expanded after September 18, 1978, having an input firing rate of >250 MMBtu/hr (>73 MW$_{th}$). The Clean Air Act Amendments of 1990, specifically Title IV – Acid Deposition Control, require a 2-million-ton reduction in the emission of nitrogen species by January 1, 2000. Although the approach will be similar to that applied to SO_2, allowing emissions averaging from two or more units, specific emission standards have not been established for all furnace types, and the exact implementation schedule is uncertain at this time. Language in Title IV does state that NO_2 emissions from tangentially fired boilers will be limited to a maximum of 0.45 lb/MMBtu (608 mg/Nm^3). Similarly, wall-fired dry bottom boilers will be limited to a maximum emission rate of 0.50 lb/MMBtu (675 mg/Nm^3). The U.S. EPA has until January 1, 1997 to establish NO_2 emission limits for remaining boiler types (i.e., wall-fired wet bottom, cyclone units, and units with cell burner technology) based on economical technology options. At this time, low-NO_x burners and various forms of combustion air staging are considered economical technology options.

Although national NO_2 regulations have been the driving force in the past for the regulation of fossil fuel-fired boiler emissions in the United States, in recent years, state and local emission regulations have begun to play a more significant role. In fact, new electrical generating units built in the last few years have been required to meet emission limits established by state and local regulatory agencies that are more restrictive than the federal

TABLE 6

U.S. Companies That Have Expressed Interest in Sulfur Dioxide Control Technology Projects in Central Europe

ABB Environmental Systems 31 Inverness Center Parkway Birmingham, Alabama 35242 Mr. Paul Yosick Director of Marketing Phone (205) 995-5321 Fax (205) 995-5496	Burns & McDonnell 4800 East 63rd Street Kansas City, Missouri 64130 Mr. John P. Werthman, P.E. Manager, Business Development Air Pollution Control Division Phone (816) 822-3437 Fax (816) 822-3415
Black & Veatch 11401 Lamar Avenue Overland Park, Kansas 66211 Mr. Leroy E. Kashka Project Manager Phone (913) 339-2431 Fax (913) 339-2934	Environmental Elements Corporation 3700 Koppers Street PO Box 1318 Baltimore, Maryland 21203 Mr. Hamilton G. Walker, Jr. Manager, International Business Phone (410) 368-7046 Fax (410) 368-6721
Pure Air 7540 Windsor Drive Allentown, Pennsylvania 18195 Mr. David W. Smith Manager, Business Development Phone (610) 481-5171 Fax (610) 481-2762	Raytheon Engineers & Constructors PO Box 5888 Denver, Colorado 80217 Mr. Paul A. Ireland Chief Engineer, Air Pollution Control Phone (303) 843-3420 Fax (303) 843-2358
Sargent & Lundy Engineers 55 East Monroe Street Chicago, Illinois 60603-5780 Mr. William DePriest Manager, Air Quality Control Services Phone (312) 269-6678 Fax (312) 269-3634	

regulations. For NO_2, limits of 0.20 lb/MMBtu (270 mg/Nm^3) and less have been required. This trend is anticipated to become more prevalent in the future for all emission types from fossil fuel-fired boiler systems.

Commercially available technologies such as overfire air (OFA) staging, low-NO_x burners (LNB), selective noncatalytic reduction (SNCR), and SCR have demonstrated their ability to control NO_2 emissions for a variety of fuel (bituminous and subbituminous coal and lignite) and boiler types around the world (Kokkinos et al., 1991; Colannino, 1993; Staudt, 1993; Kuehn, 1994; Eskinazi and Tavoulareas, 1995). In the United States, OFA and LNB are preferred by utilities because of their lower capital and operating costs and the fact that they have effectively met most regulatory requirements. However, SNCR and SCR have seen some use and are expected to see greater use in the future as regulatory activities in the United States further limit NO_2 emissions. Based on U.S. experience, both OFA and LNB should be appropriate technology options for meeting the Czech Republic NO_2 emissions limit of 650 mg/Nm^3 (0.48 lb/MMBtu) for units >0.2 MWth (megawatt thermal).

4.3.1 U.S. Experience

4.3.1.1 Low-NO_x Burners

As previously stated, the use of air and fuel staging are the preferred technology options in the United States for limiting the emission of nitrogen species from fossil fuel-fired electrical generating systems. The primary reason for this preference is low capital cost relative to other technology options, such as SNCR and SCR. However, the use of OFA and LNB technology is generally limited to reducing NO_2 emissions by 20% to 50%, depending on boiler and fuel type. Also, the use of OFA and LNB technology can reduce carbon efficiency (increase the carbon content of the ash), increase carbon monoxide (CO) emissions, and affect boiler slagging/fouling and heat transfer.

Full-scale demonstration of LNB technology has been ongoing in the United States for many years in anticipation of new regulatory limits on NO_2 emissions. The majority of the activity has focused on tangentially and wall-fired boilers, with recent demonstrations also including cell burner units and cyclone units. Full-scale demonstration results reported by Southern Company Services, Inc., in 1993 showed NO_2 emission reductions for a tangentially fired boiler firing bituminous coal ranging from 37% to 45% during test periods of 55 to 71 days (Hardman et al., 1993). These results were achieved using three levels or variations of fuel- and air-staging technology supplied by ABB Combustion Engineering Services (ABB CE) referred to as low NO_x concentric firing system (LNCFS). LNCFS Level III achieved the highest level of NO_x reduction, 45% during the long-term tests, with a resulting NO_2 emission rate of 0.34 lb/MMBtu (460 mg/Nm^3) at full load (180 MWe). Since NO_2 emissions were observed to increase with decreasing load, the annual achievable emission limit was reported to be 0.40 lb/MMBtu (540 mg/Nm^3). Other observations made during this demonstration activity included acceptable CO emissions, slight increases in carbon carryover that could be minimized by reducing the fineness of the pulverized fuel, and slagging migration from the furnace to the convective pass. Slagging in the convective pass required improved steam temperature control which was addressed by varying excess air levels and burner tilt position. Because of the demonstration nature of the project, cost data were not presented.

Tennessee Valley Authority (TVA) is one of the largest utilities in the United States, representing over 17,000 MWe of coal-fired electrical generating capacity (Manaker et al., 1993). This capacity represents nearly all coal-fired boiler types currently in operation in the United States including wall-fired units, tangentially fired units, cell burner units, cyclone units, and an FBC unit. In order to meet reductions in NO_2 emissions required by the 1990 Clean Air Act Amendments, TVA elected to average NO_2 emissions systemwide in order to minimize the cost of compliance. Phase I requirements specifically address wall- and tangentially fired units, representing roughly 4000 MWe of TVA capacity. In order to determine potential NO_2 reductions for tangential-fired units, TVA elected to retrofit one

288-MWe bituminous coal unit with ABB CE Level I LNCFS burners. Early results were described as not very encouraging, with NO_2 reductions of <20% observed resulting in NO_2 emissions of 0.45 to 0.55 lb/MMBtu (608 to 745 mg/Nm^3). TVA also conducted full-scale demonstrations on two wall-fired bituminous coal units, 150 and 200 MWe in size. Burners for these two demonstration tests were supplied by Foster Wheeler Energy Corporation (FWEC). Results from these LNB retrofits demonstrated NO_2 reduction levels of 25% to nearly 54%, with actual NO_2 emission levels reduced to 0.45 to 0.60 lb/MMBtu (608 to 810 mg/Nm^3). Conclusions based on the early demonstration tests included the need for a thorough assessment of existing equipment prior to LNB installation, the importance of personnel training, and the importance of proper air control and measurement. Also, TVA concluded that LNB performance will not be as predicted by vendors in all units and LNB operation is more complicated than conventional burner operation. Therefore, individual unit evaluation and optimization will be necessary. Although the initial results were less than anticipated in some cases, TVA proceeded with further burner optimization tests in the hope of improving LNB performance and plans to continue retrofitting LNB technology on additional units to meet NO_2 emission compliance requirements.

Ohio Edison Company completed the retrofit of a 630-MWe pulverized coal (pc)-fired cell burner unit firing bituminous coal (Dresner et al., 1993). This retrofit was awarded to the Babcock & Wilcox Company which supplied DRB-XCL® low-NO_x cell burners, OFA ports, burner wall panels, coal piping, lighters, and ductwork. Nitrogen dioxide emissions prior to the retrofit were reported to range from 1.15 to 1.40 lb/MMBtu (1555 to 1890 mg/Nm^3) with carbon carryover in the fly ash ranging from 1.6–3.7 wt%. Subsequent to the retrofit, controlled NO_2 emissions were reported to be 0.43 to 0.48 lb/MMBtu (580 to 650 mg/Nm^3) with carbon carryover in the fly ash increasing to 4–6 wt%. Further reductions in NO_2 emissions were not possible in this case without increasing carbon carryover in the fly ash, creating furnace slagging and possibly unit reliability problems and affecting reheater performance. Other observations made included the need for close attention to be paid to the superheater and increased sootblowing to control excessive slagging. An increase in excess air may be necessary in the future to avoid high furnace wall wastage, resulting in slightly higher NO_2 emissions and lower carbon carryover. The estimated capital cost in this case was US$26 to US$30/kW, with an NO_2 control cost of US$250 to US$255/ton (Dresner et al., 1993). However, the extensive nature of this retrofit is not necessarily representative of the boiler population. Therefore, these costs are believed to be high relative to more typical LNB installations.

A second cell burner retrofit completed by Babcock & Wilcox on a bituminous coal-fired 605-MWe Dayton Power & Light unit demonstrated a reduction in NO_2 emissions of >50%, with actual NO_2 emissions ranging from 0.52 to 0.55 lb/MMBtu (700 to 745 mg/Nm^3) after the retrofit (Laursen et al., 1993). Baseline NO_2 emissions ranged from 1.0 to 1.2 lb/MMBtu (1350 to 1620 mg/Nm^3). Reported CO emissions were <55 ppm, and in this case, carbon carryover in the ash decreased after the retrofit at some operating conditions. Carbon carryover usually increases subsequent to the installation of LNB. The decrease in carbon carryover in this case was believed to be the result of an improvement in combustion air distribution provided by the new burners. Tests performed at reduced load (460 and 350 MWe) showed comparable results. During normal dispatch over a 4-month period, NO_2 emissions averaged 0.51 lb/MMBtu (690 mg/Nm^3). Other observations based on this retrofit included a reduction in excess air levels from baseline, no effect on unit start-up and turndown, and no slagging or fouling problems. Ongoing efforts will continue to evaluate the potential for furnace corrosion. Although actual costs for this retrofit were not reported, the authors did report estimated costs for a 500-MWe U.S. DOE reference unit. Capital costs were estimated to range from US$8–US$12/kW in 1990 dollars.

Babcock & Wilcox DRB-XCL LNB were installed on a 250-MWe opposed wall-fired bituminous coal unit at Alabama Power Company's plant Gaston (Sorge et al., 1993). Baseline NO_2 emissions were reduced by nearly 50% at full load, 0.75 to 0.8 lb/MMBtu versus <0.4 lb/MMBtu (1015 to 1080 mg/Nm^3 versus <540 mg/Nm^3). At reduced load (150 MWe), NO_2 emissions were reduced from roughly 0.65 to 0.35 lb/MMBtu (880 to 475 mg/Nm^3). Carbon carryover values increased from 5–7 wt% to 6–11 wt%. A decrease in coal particle size did not reduce NO_2 emissions, but carbon carryover levels were reduced. Economic data were not presented for this retrofit case.

A Georgia Power Company opposed wall-fired 500-MWe bituminous coal unit was the site of a retrofit using LNB provided by FWEC (controlled flow/split flame burners) (Wingard et al., 1993). Baseline NO_2 emissions were reduced by nearly 50% for a range of load conditions. At full load, NO_2 emissions were reduced from 1.2 to 0.7 lb/MMBtu (1620 to 945 mg/Nm^3). The addition of advanced OFA further reduced NO_2 emissions. However, the 0.5-lb/MMBtu (675 mg/Nm^3) limit assumed for wall-fired boilers was not achieved in this case. Further reductions in NO_2 emissions would be possible at the expense of increased carbon carryover. Carbon carryover values increased from 2–6 wt% to 6–11 wt% for a load range of 300 to 500 MWe.

Similar FWEC burners were installed on a 650-MWe Pennsylvania Electric Company opposed wall-fired bituminous coal unit (Wingard et al., 1993). Full load NO_2 emissions were reported to be 1.3 to 1.4 lb/MMBtu (1760 to 1890 mg/Nm^3). The result of the LNB installation was an observed NO_2 emission rate of 0.5 to 0.7 lb/MMBtu (675 to 945 mg/Nm^3), representing 50% to 60% reduction in emissions. Carbon carryover levels increased from <3% prior to the retrofit to 10% after optimization steps were taken to minimize carbon carryover. At an excess air level of 20%, CO emissions were typically <50 ppm. Furnace slagging was not adversely affected by the burner retrofit, and further burner modifications are planned in order to reduce carbon carryover to more acceptable levels. No economic data were provided for this demonstration effort.

ABB Combustion Engineering Services, well known for tangential-fired units, also markets an LNB for wall-fired boilers. The RO-II LNB was tested on a 137-MWe pc-fired boiler using both bituminous and subbituminous coals (Way et al., 1993). The objective of the retrofit was to reduce NO_2 emissions below 0.5 lb/MMBtu (675 mg/Nm^3) for both fuel types at full load. However, no baseline NO_2 emissions data were collected prior to the retrofit for comparison. Test results while firing the bituminous coal indicated NO_2 emissions ranging from 0.44 to 0.53 lb/MMBtu (600 to 715 mg/Nm^3) for boiler loads ranging from 75 to 118 MWe. Carbon monoxide emissions were <100 ppm, and carbon carryover values ranged from 3.1 to 7.3 wt% depending on boiler load. Carbon monoxide and carbon carryover levels generally decreased with increasing load. When the bituminous coal was fired, it was necessary to control excess air closely in order to maintain an NO_2 emission rate of <0.5 lb/MMBtu (<675 mg/Nm^3). Test results while firing the subbituminous coal showed that NO_2 emissions ranged from 0.28 to 0.35 lb/MMBtu (380 to 480 mg/Nm^3) for boiler loads ranging from 75 to 115 MWe. Carbon monoxide emissions were <100 ppm, and carbon carryover values ranged from 0.8 to 1.1wt%. No economic information was provided for this retrofit project.

EPRI is evaluating an alternative to the installation of LNB which involves the development of techniques for reducing NO_2 emissions by fine-tuning the boiler. In order to test the concept, EPRI and Potomac Electric Power Company have completed tests on a 100-MWe tangentially fired bituminous coal unit (Levy et al., 1993). Baseline NO_2 emissions for the unit were reported to average 0.61 lb/MMBtu (825 mg/Nm^3) for a wide load variation, and local regulatory agencies indicated an intent to limit NO_2 emissions to 0.38 lb/MMBtu (520 mg/Nm^3). Results have shown that a combination of burner adjustments, boiler fine-tuning, and improved maintenance practices can reduce NO_2 emissions and maintain acceptable unit performance. In this case, NO_2 emissions were reduced by 39% to roughly 0.37 lb/MMBtu (505 mg/Nm^3) with an economizer oxygen concentration of 1.6%. Carbon carryover increased from roughly 6 to 13 wt% as a result, but carbon monoxide levels were not reported to be excessive, <50 ppm. Although waterwall wastage is a serious concern, longer-term operation at a low NO_2 condition will be required to determine if a serious problem exists. Also, a slight decrease in reheat steam temperature was observed, resulting in an increase in steam moisture content. Future efforts will attempt to determine the effect of higher steam moisture content on turbine blade erosion. Other plans call for significant instrumentation upgrades to improve monitoring capabilities for carbon monoxide, oxygen, on-line carbon carryover, and flame stability and location. Installation of automated burner and air register controls are planned to allow more precise control of settings in the hope of further reducing NO_2 emissions or maintaining current emission levels while increasing excess air and reducing carbon carryover. Because of the development nature of this demonstration, no economic data were provided. The use of boiler fine-tuning to reduce NO_2 emissions and improve boiler performance overall has been reported elsewhere (Mizell, 1994). Many in the industry believe that it is prudent to complete boiler optimization and fine-tuning studies prior to evaluating retrofit technology options for reducing NO_2 emissions in order to make the most cost-effective use of technology options.

4.3.1.2 Natural Gas Reburning

The use of natural gas in a boiler designed to fire coal is an option many U.S. utilities are evaluating for reducing NO_2 emissions. One of three general approaches is typically used: seasonal natural gas firing, natural gas cofiring, and natural gas reburning (NGR). Seasonal natural gas firing involves the replacement of the primary fuel (coal) during certain times of the year with gas. Natural gas prices normally dictate seasonal use in the summer. For many utilities, the primary reason for seasonal gas use is the annual reduction of SO_2 emissions. However, significant reductions in NO_2 emissions can also be achieved depending on specific unit design characteristics. Similarly, gas cofiring is typically used to reduce SO_2 emissions, but can also reduce NO_2 emissions depending on the amount of gas used and the fuel-firing configuration. Generally, gas cofiring will result in higher NO_2 emissions than 100% seasonal gas use.

NGR for the reduction of NO_2 emissions will be the focus of the remainder of this section. Gas reburning generally involves the replacement of 15%–20% of the primary fuel with natural gas on a heat input basis. Unlike simple cofiring, reburning involves the injection of the gas above the primary coal combustion zone, creating a slightly fuel-rich zone. The objective is to reduce nitrogen species formed in the primary combustion zone as they pass through the fuel-rich zone. Additional air (OFA) is added at a slightly higher elevation in the furnace to burn out remaining combustibles effectively. This approach can effectively reduce NO_2 emissions by as much as 60% to 70% in some cases.

The Energy and Environmental Research Corporation (EER) has been involved in the development and demonstration of NGR technology for many years. Recent publications summarize the results from three demonstration sites: a 71-MWe tangentially fired unit, a 172-MWe front wall-fired unit, and a 33-MWe cyclone-fired unit representing U.S. DOE Clean Coal Technology Demonstration Program projects (Folsom et al., 1993; Opatrny et al., 1994; Pratapas and Bluestein, 1994). Baseline NO_2 emissions for the tangentially fired unit firing bituminous coal were reported to be 0.75 lb/MMBtu (1015 mg/Nm^3). Parametric testing with NGR demonstrated NO_2 reduction ranging from 60% to 70% when natural gas represented 18% of the fuel heat input. Actual NO_2 emissions ranged from 0.23 to 0.30 lb/MMBtu (315 to 410 mg/Nm^3). Reducing the natural gas feed to 10% of the fuel heat input reduced NO_2 emissions by 55% to 0.34 lb/MMBtu (465 mg/Nm^3). Long-term tests on the tangentially fired unit with normal daily cycling demonstrated an average NO_2 emission rate of 0.245 lb/MMBtu (335 mg/Nm^3). Inspection, ultrasonic measurements, and destructive tube testing did not indicate an increase in tube wastage, even though the reducing zone created in the boiler by the reburn fuel was a concern relative to tube wastage. Also, NGR had no significant effect on CO emissions or carbon carryover. No economic data were presented for this demonstration.

The front wall-fired unit firing subbituminous coal involved the use of both LNB and NGR. Baseline NO_2 emissions for the wall-fired unit were reported to be 0.73 lb/MMBtu (985 mg/Nm^3). The optimized LNB installed by FWEC reduced NO_2 emissions by 37% to nearly 0.46 lb/MMBtu (630 mg/Nm^3) without NGR. The combination of LNB and NGR reduced NO_2 emissions by a maximum of 72% to 0.20 lb/MMBtu (275 mg/Nm^3) when natural gas represented 23% of the fuel heat input during parametric tests. Long-term LNB and NGR performance testing demonstrated an average NO_2 emissions rate of 0.26 lb/MMBtu (355 mg/Nm^3) for gas injection rates of 5%–19% of the unit fuel heat input. Integration of NGR and the LNB installation actually reduced the CO emissions and carbon carryover observed for the LNB installation alone. The effect of NGR on tube wastage on this unit is still being evaluated. The capital cost for this demonstration was US$25 to US$30/kW. Operating costs were stated to be the difference between the coal and gas fuel costs.

ABB Combustion Engineering has developed an NGR concept referred to as close coupled gas reburn technology that reduces the distance in the boiler between the primary combustion zone and the reburn zone. The concept was demonstrated on a 400-MWe Kansas Power and Light tangentially fired unit firing subbituminous coal (Pratapas and Bluestein, 1994; Lewis et al., 1993). This particular fuel has limited unit output to roughly 300 MWe. Previous installation of burners with an OFA capability had reduced NO_2 emissions by 48%. The use of NGR with 10% and 20% gas reburn fuel reduced NO_2 emissions by an additional 25% and 41%, respectively. However, the effectiveness of NGR decreased with decreasing load. The resulting NO_2 concentrations in the flue gas were reported to be as low as 100 ppm on a 3% oxygen basis. Boiler performance observations included no significant change in furnace exit gas temperature; minor changes in furnace temperatures and heat transfer were observed; and overall boiler efficiency decreased because of increased flue gas moisture content. No economic data were presented.

Typical air staging and LNB designs are not applicable to cyclone-fired units. Therefore, NGR is one of few technical options available for reducing NO_2 emissions from this boiler type. In an EER publication, baseline NO_2 emissions for a cyclone-fired unit were reported to be 0.97 lb/MMBtu (1310 mg/Nm^3) (152). Parametric testing with NGR demonstrated NO_2 reduction ranging from 50% to 67% when natural gas represented 15% and 25% of the fuel heat input, respectively. Actual NO_2 emissions ranged from roughly 0.23 to nearly 0.49 lb/MMBtu (315–670 mg/Nm^3). Long-term tests on the cyclone-fired unit with normal daily cycling demonstrated an average NO_2 emission rate of 0.333 lb/MMBtu (455 mg/Nm^3). Although CO emissions and carbon carryover data were not reported for the cyclone-fired unit, no change in these operating parameters would be expected because of the cyclone's intense firing characteristics. The effect of NGR on tube wastage on this unit is still being evaluated, and no economic data were presented for this demonstration.

ABB Combustion Engineering reported NGR demonstration results from an Ohio Edison 114-MWe bituminous coal-fired cyclone boiler (Borio et al., 1993). To avoid slag tap problems, NGR was used only when the boiler was operated at loads of >80 MWe and the NGR fuel represented 16% of fuel heat input for the unit at all load conditions. At full-load conditions, NO_2 emissions were reduced by roughly 50% from 0.53 to 0.26 tons/hr. As load decreased, baseline NO_2 emissions decreased, and the level of NO_2 reduction also decreased such that at 85 MWe, NO_2 reduction was only 30%, but actual NO_2 emissions were roughly 0.24 tons/hr. Therefore, actual NO_2 emissions were nearly constant over the load range. This demonstration showed that the use of flue gas recirculation (FGR) to improve the mixing of the reburn fuel created unacceptable ash deposition on secondary furnace surfaces. The increase in deposition was believed to be caused by the cooling effect of FGR, and the use of FGR was discontinued, simplifying the NGR equipment requirements without any obvious effect on NO_2 reduction. As with other NGR demonstration tests, no increase in tube wastage was observed. Boiler cycling has a significant effect on NGR NO_2 reduction such that baseload units would be expected to achieve lower NO_2 emissions than cycling units. Also, excessive CO emissions were reported to limit further reductions in NO_2 emissions. Overall, project participants concluded that further NGR demonstrations would be required on additional cyclone-fired units before adequate information would be available to evaluate the commercial potential of NGR technology for controlling NO_2 emissions from cyclone units.

The demonstration of NGR by U.S. companies has not been limited to U.S. utilities. U.S. EPA sponsored a demonstration of NGR using FGR on a 300-MWe coal-fired boiler in the Ukraine involving representatives from Russia and the Ukraine (LaFlesh et al., 1993). ABB Power Plant Laboratories provided a preliminary NGR system design along with instrumentation and technical support to permit evaluation of the NGR system performance. Final system design, fabrication, and installation were completed by the Russian and Ukrainian participants. The 300-MWe opposed wall-fired slagging boiler fired a range of fuels, including a high-volatile Ukrainian bituminous coal, Siberian lignite, and various blends. During the NGR test, a fuel blend was used consisting of 90%–95% bituminous coal and 5%–10% lignite. Baseline NO_2 emissions were reported to be 0.82 lb/MMBtu (1110 mg/Nm^3) with a carbon carryover of 1–2 wt% in the fly ash. Using NGR, NO_2 emissions were reduced by 40% to 60% for various system conditions and a load range of 200 to 300 MWe. NGR was discontinued at boiler loads of <200 MWe to avoid slag flow problems. On the average, NO_2 emissions were reduced by 50% while maintaining CO emissions at <100 ppm and limiting carbon carryover to 2–3 wt% in the fly ash using 12% reburn fuel. No significant negative impacts on boiler performance were noted, and the success of the project is expected to result in the installation of NGR systems on additional Ukrainian boilers as financial conditions permit.

Reburning demonstration tests have not been limited to the use of natural gas as the reburn fuel. Babcock & Wilcox evaluated the use of pulverized coal as a reburn fuel on a 100-MWe Wisconsin Power and Light cyclone unit (Yagiela et al., 1992; Newell et al., 1993). Both bituminous and subbituminous coals were fired during this U.S. DOE Clean Coal Demonstration Program project. The use of pulverized coal as the reburn fuel requires that the reburn fuel represent a larger percentage of the total fuel input when compared to natural gas, 20% to 35% versus 10% to 20%. Key process issues include proper control and mixing of the coal and air in the reburn and OFA zones and flue gas residence time in the reburn zone. While firing an Illinois bituminous coal, NO_2 emissions were reduced by nominally 55% with a 10% to 15% increase in carbon carryover using 34% reburn fuel. For boiler loads of >80 MWe, NO_2 emissions were <0.4 lb/MMBtu (<545 mg/Nm^3). However, for boiler loads <80 MWe, NO_2 emissions ranged from <0.4 to nearly 0.55 lb/MMBtu (<545–750 mg/Nm^3) with NO_2 reduction decreasing to 33%. Results with the subbituminous coal were somewhat better, with a nominal NO_2 reduction of 61% and no change in carbon carryover. In addition, NO_2 reduction was fairly constant over the range of boiler loads evaluated using 30% reburn fuel. Actual NO_2 emissions with the subbituminous coal ranged from roughly 0.25–0.34 lb/MMBtu (340 to 465 mg/Nm^3). Neither fuel resulted in any significant change in furnace slagging or fouling, and no furnace corrosion was observed. The capital cost of the demonstration was US$66/kW. Subsequent to completing the demonstration, Wisconsin Power & Light elected to continue operating the reburn system while firing the unit on subbituminous coal.

4.3.1.3 Selective Noncatalytic Reduction

Postcombustion NO_2 control options can include in-furnace as well as postfurnace technologies. SNCR is a postcombustion, in-furnace technology that has been evaluated for use in gas-, oil-, and coal-fired boilers where nitric oxide (NO) is converted into nitrogen, water, and carbon dioxide depending on the reducing agent used (Kokkinos et al., 1991). SNCR technology involves the injection of a reducing agent into a defined flue gas temperature window in the furnace above the flame zone. This temperature window has been defined as broadly as 1400° to 2000°F. However, the actual effective temperature window is narrower for individual reducing agents such as ammonia and aqueous urea and can be modified with additives. Ammonia and urea are the two most widely used reducing agents. The importance of the temperature window cannot be overstated because if the reducing agent is injected at a higher temperature, the reducing agent will be oxidized to NO or NO_2. If the reducing agent is injected at a low temperature, significant ammonia slip, nitrous oxide (N_2O) formation, and CO emissions can result depending on the specific reducing agent. Other key parameters affecting the performance of SNCR systems include flue gas residence time within the temperature window, adequate mixing of the reducing agent with the flue gas, baseline NO_2 concentrations, and CO concentrations.

SNCR technology has been demonstrated on coal-fired boilers and is available commercially in the United States from several companies. Most of the demonstrations and commercial installations are using an aqueous form of urea, with NO_2 reductions reported to range from 30% to 75% for baseline NO_2 emissions of 0.8 to 1.2 lb/MMBtu (1080–1620 mg/Nm^3) and various boiler types (front wall-fired, tangentially fired, top-fired) and sizes (40–110 MWe) and fuel types (medium- and low-sulfur bituminous coal) (Hofman et al., 1993; Rini et al., 1993; Hunt et al., 1993; Braczyk et al., 1994; Gregory et al., 1993). Actual controlled NO_2 emissions for various units are reported to range from 0.3 to 0.5 lb/MMBtu (410 to 680 mg/Nm^3) with changes in load having various effects on SNCR performance. For a 100-MWe coal-fired unit, 40% NO_2 reduction has been reported with an ammonia slip of 10 ppm and 25%–30% N_2O production. In some cases, NO_2 reduction increases with increasing load, and in other cases the opposite is true. Reductions in NO_2 emissions are limited by high ammonia slip, the formation of N_2O, increased CO emissions, and poor load-following capabilities in some cases.

Potential problems or technology limitations include controlling ammonia slip, limiting ammonia in the ash, limiting N_2O formation, limiting CO emissions, and effective load following. Ammonia slip concentrations were reported to range from <10 to >50 ppm in the flue gas, with acceptable concentrations reported to be <2 to 10 ppm. Even in cases where ammonia slip was relatively stable at 5 ppm, ammonia slip spikes were periodically observed in the range of 10 to 30 ppm. Ammonia concentrations in fly ash were reported to be >80 ppm, an acceptable industry standard for some with others stating that an ammonia concentration of >5 ppm can be problematic for fly ash reuse and disposal. Excessive ammonia slip will result in air heater deposition problems because of the formation of ammonium sulfate/bisulfate, cause fly ash handling/disposal/reuse problems, and possibly result in a visible plume. Nitrous oxide formation was reported to range from 10%–30% of the total NO_2 reduction observed for a range of parametric conditions and is significantly less for ammonia than urea. Concern over N_2O formation is based on its potential for future regulation because of its role in atmospheric ozone chemistry and its role as a greenhouse gas. Carbon monoxide emissions were reported to increase by 5–25 ppm from baseline for a range of parametric conditions.

The cost of SNCR technology for coal-fired systems has been reported to range from US\$500–US\$1000/ton of NO_2 removed, with capital costs reported to be US\$8 to US\$22/kW depending on unit size, age, and other unit-specific factors. However, the use of additives to modify the temperature window or limit by-product formation can increase these costs. Capital cost savings can be realized if SNCR systems are installed on more than one unit simultaneously as a result of common reagent storage and circulation equipment and common engineering and installation costs.

4.3.1.4 Selective Catalytic Reduction

SCR is a postcombustion NO_2 control technology that has seen wide commercial use in Europe and Japan and is beginning to see commercial use in the United States on gas-, oil-, and coal-fired systems (ABB Power Plant Laboratories, 1994; Cho, 1994). Generally considered the most efficient technology for NO_2 control, SCR systems are typically designed to reduce NO_2 emissions by 80%. The control of NO_2 emissions is accomplished by injecting a reducing agent (aqueous or anhydrous ammonia) into the flue gas at air heater inlet temperatures in the presence of a catalyst. The ammonia reacts with NO and NO_2 to form nitrogen and water as by-products in the gas-phase reaction. Although SCR technology has been shown to be capable of reducing NO_2 emissions by 80%–90%, most potential users in the United States do not feel it has been adequately demonstrated for successful technical and economical application to coal-fired boilers. Key issues identified include catalyst cost, catalyst poisoning, ammonia slip, ammonium sulfate/bisulfate deposition on back end heat-transfer surfaces, fly ash handling/reuse/disposal problems, oxidation of SO_2–SO_3, and retrofit difficulties caused by space requirements to locate the SCR reactor between the economizer and air heater. In recent years, extensive work by catalyst vendors in the United States has focused on the development of various catalyst types in order to limit catalyst poisoning potential and provide effective catalysts for a range of flue gas temperatures (Heck et al., 1993). These catalysts generally fall into three categories: precious metals (350°–550°F), base metals (500°–840°F), and zeolites (>750°F).

U.S. coal-fired experience with SCR technology has been limited to subscale demonstration tests and a few commercial installations. Coal-fired demonstration tests at the 1-MWe scale have been ongoing for several years to document SCR performance for U.S. coals. Coal characteristics considered potentially problematic for SCR catalysts include high-sulfur content and the potential for ash constituents (alkali and some trace elements) to reduce catalyst reactivity. Results from a high sulfur (3%) bituminous coal test have shown 80% NO_2 reduction and <5-ppm ammonia slip for a V/Ti catalyst (Huang et al., 1993). However, after 14,000 hours of operation, catalyst performance degraded such that ammonia slip exceeded 5 ppm. Catalyst degradation was caused by catalyst plugging as a result of ash collection in the channels of the honeycomb structure and sulfur compounds blocking catalyst surface. Catalyst deactivation was also caused by poisoning because of arsenic and alkali components in the ash. Absorption of ambient moisture during system outages also contributed to catalyst degradation. Differential pressure measurements across the SCR reactors were found to be a good indicator of catalyst plugging problems. The use of sootblowers at various elevations in the SCR system is expected to be beneficial to reduce catalyst plugging and limit the extent of chemical poisoning. Simultaneous tests with a zeolite catalyst showed a greater impact on performance, with ammonia slip exceeding 5 ppm after only 4500 hours of operation. Conversion of SO_2 to SO_3 was generally less than 1% for SO_2 concentrations of 1500 to 3000 ppm. However, initial conversion rates for the zeolite catalyst were >2% and possibly contributed to the faster degradation of the zeolite catalyst performance. Because of the nature of this demonstration effort, economic data were not presented.

A second test on a coal-fired system was carried out under low-sulfur conditions (Jankik et al., 1993). In this case, the SCR system was located downstream of an FGD system. This low-ash, low-sulfur environment proved to be quite favorable for SCR performance. However, the expense of flue gas reheat to appropriate SCR temperatures must be considered. Results show that two V/Ti catalysts maintained 80% NO_2 reduction and <5 ppm ammonia slip for 7 months. After 11 months, a high level of reactivity (80% NO_2 reduction and <5 ppm ammonia slip) was maintained by one catalyst, but the second catalyst showed significant increases in ammonia slip (>10 ppm at 80% NO_2 reduction). The reasons for degradation of the second catalyst appear to be the result of system start-ups/shutdowns and fine particulate (fly ash and FGD solids) escaping the FGD system. Jankik et al., 1993, speculated that moisture present as a result of start-ups and shutdowns was responsible for promoting the physical or chemical attack responsible for catalyst deactivation. Conversion of SO_2 to SO_3 was in the range of <1% to nearly 4%, depending on SCR temperature with inlet

SO_2 concentrations of 120 to 150 ppm. One key issue for this SCR configuration is the performance of the recuperative heat exchanger to raise flue gas temperature to appropriate levels downstream of the FGD system. Capital and operating costs of this component will be significant, and potential impacts from deposition because of ammonia slip and the corrosive environment downstream of the FGD system require thorough evaluation. Because of the nature of this demonstration effort, economic data were not presented.

Black & Veatch developed an overall unit design to meet more stringent emission limits based on a 460-MWe bituminous coal-fired system for the Orlando Utilities Commission (Cochran et al., 1993). Particulate and SO_2 emissions will be controlled using an ESP and wet limestone FGD. Emission limits established for the system for NO_2 were 0.17 lb/MMBtu (230 mg/Nm^3) with <5-ppm ammonia slip. The overall system approach to meeting the NO_2 limit will involve the use of a Babcock & Wilcox wall-fired unit equipped with LNB capable of limiting NO_2 emissions to 0.32 lb/MMBtu (435 mg/Nm^3). Based on a technical and economic evaluation of SNCR and SCR experience, Black & Veatch elected to use SCR to further reduce NO_2 emissions by nearly 50% to reach the 0.17 lb/MMBtu (230 mg/Nm^3) emission limit. A plate-type catalyst was selected along with anhydrous ammonia as the reducing agent to achieve 50% NO_2 reduction and limit ammonia slip to 2 ppm. Catalyst life was assumed to be 2 years, and although continuous emissions monitors will be necessary to document NO_2 emissions, ammonia slip can be adequately monitored by measuring the ammonia in the fly ash. Designing the SCR system to limit ammonia slip to 2 ppm increased catalyst cost. However, advantages include reduced impacts on downstream equipment (air heater, ESP, and FGD system), reduced impacts on fly ash handling/reuse/disposal, and reduced forced outage rates. Economic data presented showed SCR capital costs were US$32 million assuming a 5-ppm ammonia slip and US$35.4 million assuming a 2-ppm ammonia slip. Capital costs for the SNCR option were reported to be US$2.8 million. On a levelized-cost basis, SNCR costs were estimated to be US$11.6 million versus US$10.9 million (5-ppm ammonia slip) and US$9.1 million (2-ppm ammonia slip) for the SCR options.

The use of SCR in combination with SNCR is also being evaluated in order to optimize overall system efficiency and minimize cost. Pilot-scale results show >80% NO_2 reduction and <5-ppm ammonia slip with substantially less SCR catalyst required (Krigmont et al., 1993). A successful demonstration of this concept has been completed for a 110-MW gas-/oil-fired boiler, and future plans intend to address a similar demonstration on a coal-fired boiler (Gullett et al., 1994).

4.3.1.5 NO_x Control Costs

The use of a single technology option for controlling NO_2 emissions from a group of boilers is highly unlikely. Technical and economic constraints will dictate the evaluation and eventual use of several technology options individually and in combination. The technology options discussed (LNB, NGR, SNCR, and SCR) have all been shown to have application individually under specific circumstances as have some combinations. For example, the combination of LNB and NGR may be an appropriate combination in one case, with LNB and SCR applied in a second. Other reasonable combinations may include 1) LNB and SNCR; 2) SNCR and SCR; 3) LNB, NGR, and SCR; and 4) LNB, SNCR, and SCR.

Because of the nature of NO_2 control demonstration projects (unit-specific issues and the various levels of testing sometimes required), most projects do not present cost information. A recent paper presented by Sargent & Lundy discussed general cost information for furnace and postfurnace NO_2 control technology options based on 1994 U.S. dollars (DePriest and Mazurek, 1994). Data were presented for three furnace technology options: LNB, LNB and OFA, and NGR for wall-fired and tangentially fired units. The capital cost of retrofitting NO_2 control technology for a nominal 660-MWe wall-fired unit ranged from US\$13–US\$18/kW for LNB (0.45–0.60 lb/MMBtu or 615–820 mg/Nm^3) to US\$20–US\$25/kW for LNB and OFA (0.35–0.45 lb/MMBtu or 480–615 mg/Nm^3). Capital cost for NGR was estimated to be US\$21–US\$27/kW for NO_2 emissions controlled to a range of 0.35–0.45 lb/MMBtu (480–615 mg/Nm^3). Similar data were presented for a nominal 375-MWe tangentially fired unit with reported costs of US\$15–US\$20/kW, US\$18–US\$23/kW, and US\$28–US\$34/kW, respectively, for LNB (0.40–0.45 lb/MMBtu or 545–615 mg/Nm^3), LNB and OFA (0.30–0.35 lb/MMBtu or 410–480 mg/Nm^3), and NGR (0.25–0.35 lb/MMBtu or 340–480 mg/Nm^3).

Capital costs were also discussed for two postcombustion NO_2 control technologies: SNCR and SCR. These costs were based on a nominal 600-MWe unit firing a high-sulfur bituminous coal with an NO_2 emission limit of 0.30 lb/MMBtu (410 mg/Nm^3). Capital costs for SNCR were reported to range from US\$10–US\$22/kW, assuming a 50% NO_2 reduction capability. The low capital cost of SNCR is due to its limited equipment requirement, with operating costs dependent on the cost of the chemical reducing agent. SNCR technology is usually a better choice for units requiring limited NO_2 reduction and having a low capacity factor. For SCR technology, an NO_2 reduction of >80% is possible and represents its primary advantage. However, the reported capital cost is significantly greater, US\$60–US\$100/kW. The broader range for and higher cost of an SCR retrofit is due to the site-specific nature of SCR retrofits, cost of catalyst, required ductwork modifications to install the SCR catalyst between the economizer and the air heater, potential air heater upgrades, and the potential need for an economizer bypass to adequately control SCR temperature.

4.3.2 Options for the Czech Republic Power Industry

Although no information was available concerning the range of NO_2 emissions from the various electrical generating units in the Czech Republic, 1990 NO_x emissions for electrical and district heating units was reported to be 217,242 metric tons, with annual emissions from all sources totaling 742,000 metric tons (3, 130). By 1992, total annual NO_x emissions were reduced to 698,000 metric tons. This evaluation assumes that current actual NO_2 emissions from most coal- and lignite-fired units exceed the 650 mg/Nm^3 (0.48 lb/MMBtu) standard for units having a capacity of >0.2 MWth. One key to successfully implementing cost-effective technology to meet the NO_2 emission limit will be to evaluate NO_2 control options in combination with any other unit- or stationwide changes planned. For example, plans for fuel switching and boiler upgrades such as new mills and burners must be factored into the NO_2 control evaluation process in order to effectively control cost and meet emission limit objectives. For new units, the selection of NO_2 control technology should be factored into the bid process for the overall unit, with economics, performance, and reliability motivating the decision process. Since the scope of this study was limited and no information was available concerning the status and condition of the existing units and their layout, it was not possible or appropriate to discuss technology or equipment options in detail. Therefore, the intent is to briefly describe a range of technology options and identify U.S. companies that have shown an interest in projects in central Europe and have demonstrated experience relative to the applicable technology options.

Control technology for NO_2 has not been applied previously in Czech Republic power stations; therefore, the first step must be to establish viable technology retrofit options for reducing NO_2 emissions prior to considering detailed evaluations of the alternative technologies. In cases where individual units or entire stations are to be repowered using AFBC boilers, NO_2 emissions from AFBCs would be expected to meet the 650-mg/Nm^3 (0.48-lb/MMBtu) NO_2 limit. Repowering using gas-fired boilers may also be an appropriate option for some aging units because of the poor quality of the available domestic lignite. If gas-fired boilers are selected, no requirement for NO_2 control is anticipated beyond those designed into the firing system of modern units. In cases where existing units are not repowered, U.S. companies recommend that combustion equipment upgrades (mills, burners, etc.) and boiler tuning can typically reduce NO_2 emissions by 50%. In addition, the use of OFA can reduce NO_2 emissions by 5% to 15%. However, care must be taken to review boiler design thoroughly in order to determine the feasibility of combustion modifications and avoid operability problems that can affect system reliability and change heat-transfer characteristics.

Because of the age of the units in the Czech Republic, a very low-cost approach to NO_2 control is required. The use of combustion controls would be the least-cost option for reducing emissions and should be thoroughly evaluated prior to considering postcombustion options. Another option to be considered would involve switching to a higher-quality fuel in order to improve the potential for combustion modifications alone to meet the 650-mg/Nm^3 (0.48-lb/MMBtu) NO_2 limit. Even though switching to or blending of higher-quality fuels would be expected to increase NO_2 emissions, the combination of large furnace volume, equipment upgrades, and system tuning should result in NO_2 emissions well below the 650-mg/Nm^3 (0.48-lb/MMBtu) limit.

For some units, the combination of fuel switching and/or equipment upgrades alone may not be sufficient to meet the 650-mg/Nm^3 (0.48-lb/MMBtu) NO_2 limit. SNCR technology is an option worth considering and, for some units, would most likely be a better choice than SCR. However, the performance of SNCR technology is very sensitive to flue gas temperature and flow distribution in the furnace. Therefore, a thorough physical evaluation of individual boilers will be required along with modeling of boiler heat-transfer characteristics to determine if SNCR technology is technically and economically appropriate. Nitrogen dioxide reduction as a result of SNCR would not be expected to exceed 50% and would more likely be closer to 25% in some cases. For some units, in order to meet the 650-mg/Nm^3 (0.48-lb/MMBtu) NO_2 limit, SCR technology may be the best choice. The use of postcombustion technologies such as SNCR or SCR may be technically appropriate, but their use should only be considered if there is economic incentive to do so and/or emissions trading options are not permitted. If emissions trading is permitted, one option may be to overcontrol NO_2 emissions on a few units using a combination of technology options in order to minimize the overall cost of reducing NO_2 emissions systemwide.

Table 7 lists and identifies a point of contact for U.S. companies that have shown an interest in Central European projects and have demonstrated experience concerning NO_2 control technology options appropriate for the Czech Republic power industry. It cannot

TABLE 7

U.S. Companies That Have Expressed Interest in Nitrogen Species Control Technology Projects in Central Europe

ABB Combustion Engineering Boiler Business Area
200 Great Pond Drive
Windsor, Connecticut 06095-0568
Mr. Thomas R. Connors
Director of Strategic Development
Phone (203) 285-9090
Fax (203) 285-5987

Black & Veatch
11401 Lamar Avenue
Overland Park, Kansas 66211
Mr. Leroy E. Kashka
Project Manager
Phone (913) 339-2431
Fax (913) 339-2934

Sargent & Lundy Engineers
55 East Monroe Street
Chicago, Illinois 60603-5780
Mr. William DePriest
Manager, Air Quality Control Services
Phone (312) 269-6678
Fax (312) 269-3634

Burns & McDonnell
4800 East 63rd Street
Kansas City, Missouri 64130
Mr. John P. Werthman, P.E.
Manager, Business Development
Air Pollution Control Division
Phone (816) 822-3437
Fax (816) 822-3415

Raytheon Engineers & Constructors
PO Box 5888
Denver, Colorado 80217
Mr. Paul A. Ireland
Chief Engineer, Air Pollution Control
Phone (303) 843-3420
Fax (303) 843-2358

be overstated that the general comments made concerning technology options for reducing NO_2 emissions are just that, general comments. These comments are based on limited information. Ultimately, any detailed station or unit rehabilitation plans must be based on thorough, detailed technical evaluations of each unit, including the consideration of social and economic constraints specific to the Czech Republic. A key element to minimizing the cost of NO_2 control technology options would be the manufacture of components in the Czech Republic or other Central European countries where possible.

4.4 Integrated Emissions Control Systems

A number of integrated concepts for controlling emissions (particulate, SO_2, and NO_2) from coal-fired systems are at various stages of evaluation and/or demonstration. Some are intended to simultaneously control SO_2 and nitrogen species (NO and NO_2); a few target simultaneous control of particulate and nitrogen species; and still others are intended to control particulate, SO_2, and nitrogen species simultaneously. The U.S. DOE Clean Coal Demonstration Program is supporting two integrated concepts for simultaneous control of SO_2 and nitrogen species. The NOXSO process controls SO_2 and nitrogen species in a two-stage fluid-bed absorber, operated at 250°F and located downstream of a conventional particulate control device, employing an alkali-impregnated alumina sorbent (Haslbeck et al., 1993; Black et al., 1993; Zhou et al., 1993). Emissions control is reported to be 95% for SO_2 and 80% for nitrogen species. Spent sorbent is regenerated in a multistep process where the nitrogen species are recycled back to the boiler for reduction and the SO_2 is reduced to hydrogen sulfide (H_2S) and other reduced sulfur forms using methane prior to entering a sulfur recovery plant.

The copper oxide process was also developed for the purpose of simultaneous control of SO_2 and nitrogen species (Markussen and Pennline, 1993; Roberts, 1993). In this case, the flue gas is contacted with a copper-impregnated alumina sorbent in a moving- or fluid-bed absorber operated at about 750°F to achieve 90% SO_2 capture and 90% reduction of nitrogen species. Sulfur dioxide is captured as copper sulfate, and simultaneous reduction of nitrogen species is accomplished in the absorber as a result of ammonia injection, with the copper sulfate acting as a catalyst. Spent sorbent is transferred to a regenerator operated at elevated temperatures using methane to reduce the copper sulfate and produce a concentrated SO_2 stream for processing in a sulfur recovery plant. The copper-based sorbent is recycled to the absorber.

A process referred to as CombiNO$_x$ makes use of a combination of nitrogen species control concepts (LNB, NGR, and SNCR), methanol injection, and wet scrubber technology to achieve >95% SO_2 capture and 90% NO_2 capture. Simply stated, the NO not controlled by the combination of LNB, NGR, and SNCR is oxidized to NO_2 as a result of the methanol injection. The NO_2 and SO_2 are captured in a wet scrubber using both sodium carbonate and calcium carbonate as alkali sources along with a sodium thiosulfate additive. Evaluation of this concept has been limited to pilot-scale tests to-date (Zamansky et al., 1993).

Babcock & Wilcox is pursuing, with U.S. DOE support, the development of a simultaneous emissions control concept referred to as the "SO_x-NO_x-RO_x Box" (Redinger and Corbett, 1993; Holmes et al., 1993). The basic premise is the simultaneous control of particulate, SO_2, and nitrogen species in a hot-side baghouse. Particulate control is accomplished as a result of conventional filtration mechanisms in a pulse-jet baghouse operated at 800° to 900°F. Sulfur dioxide capture is reported to be >70% using hydrated lime ($Ca[OH_2]$) injection upstream of the hot-side baghouse. The emission of nitrogen species is reduced by >90% as a result of ammonia injection upstream of the baghouse and the location of an SCR catalyst on the clean side of the pulse-jet filter bags. Ammonia slip was reported to be <5 ppm. An economic evaluation was completed based on the results from a 5-MWe equivalent demonstration. Capital costs for a 250-MWe coal-fired plant were estimated to be US$258/kW, assuming 90% SO_2 and NO_2 control and a particulate limit of 0.03 lb/MMBtu.

ABB Environmental Systems is evaluating the SNOX process with support from the U.S. DOE Clean Coal Program (Steen et al., 1993). This process is intended to make use of an integrated hot-side filter and SCR catalyst for particulate control and nitrogen species reduction using ammonia as the reducing agent. Flue gas exiting the integrated filter/SCR component enters a reactor containing an oxidizing catalyst for the purpose of oxidizing SO_2 to SO_3. The flue gas then enters a falling film condenser to recover sulfuric acid. A recent demonstration effort has shown that reasonable particulate control and >90% SO_2 and NO_2 control are possible while recovering a salable sulfuric acid product.

Although these integrated emission control concepts show promise for future commercial applications, their high capital costs and lack of commercial experience make them poor choices at this time for meeting the near-term requirements of the Czech Republic's power industry. However, construction of new coal-fired power stations throughout the world in the next century is expected to make use of highly efficient emission control technologies such as these to effectively control emissions and produce salable by-products rather than solid wastes requiring disposal.

5.0 ADVANCED POWER GENERATION SYSTEMS

Based on information presented at the Prague workshop on "Least-Cost Economic Power Generation in East Central Europe" sponsored by the U.S. DOE in November 1994, independently operated regional heating plants are potentially interested in using IGCC and PFBC for retrofitting suitable lignite-fired combined heat and power cogenerated plants. Interest is centered on the large economic lignite reserves in north and western Bohemia, represented by the coal analysis previously presented in Table 1. Interest has also been expressed in natural gas-fired turbines, which could be converted to coal gas if natural gas prices increase faster than coal prices. In the future, underground coal gasification (UGC) may also be of interest for power production.

The following sections provide 1) an overview of the status and availability of advanced power technologies, including the U.S. Clean Coal Technology Demonstration Projects; 2) heat and material balances for selected technologies applied to Bílina lignite, with sensitivity determinations for property changes (e.g., coal cleaning or drying); and 3) summary information on technologies provided by vendors.

5.1 First-Generation Advanced Power Systems

Advanced power systems that have used low-rank coals (LRCs) at or near commercial scale include the ABB Combustion Engineering PFBC unit in Spain; Texaco, Dow, and Shell IGCC systems in the United States; and the Winkler and Lurgi gasification systems in Germany. These first-generation systems offer efficiencies of 38%–41% at projected mature capital costs of US$1200–US$2000/kW. Comparable efficiencies can be achieved in advanced supercritical pc-fired boilers. Of the leading U.S. systems, the Texaco, Dow/Destec and Shell IGCC units, using entrained-flow gasifiers equipped with cold-gas cleaning, offer substantial improvement in sulfur control (99+%) at projected capital costs comparable or lower than those of pc-firing. The system having the lowest reported cost (Destec) uses a two-stage slurry feed, which provides some flexibility for burning high-moisture lignites, although not as much as the dry-feed Shell gasifier. The first-generation Texaco IGCC system, which uses a single-stage slurry feed gasifier requiring a higher oxygen feed rate and heat recovery duty, does not appear to be competitive for high-moisture coal unless the feed coal is blended with petroleum coke or is hydrothermally dried. First-generation PFBC units are approximately equivalent to supercritical pc-fired boilers in cost, efficiency, and sulfur removal.

5.2 Second-Generation Advanced Power Systems

Future U.S. goals for market-driven power systems advanced by DOE planners are listed in Table 8 (Notestein and Moore, 1990; Salvador and Mahajan, 1992). The low capital cost goal of US$1000/kW can be met only by highly simplified systems based on hot-gas cleanup, with minimum heat recovery and reheat duty. Combined cycle efficiencies of 45%–50% will require that pristine fuel or combustion gases is delivered to gas turbines operating at 1260°–1371°C (2300°–2500°F). These future performance goals will have to be met under more stringent environmental requirements, including 95%–99% sulfur control and NO_x emissions as low as 0.1 lb/MMBtu (150 mg/scm). Air toxic emissions pose as yet unknown requirements. First-generation advanced systems cannot meet all of these requirements, and

TABLE 8

U.S. DOE Goals for Future Market-Driven Coal-Fired Power Systems

Capital Cost	Under US$1000/kW
Efficiency	45%-50%
Sulfur Control	95%-99%
NO_x Control	0.1-0.3 lb/MMBtu
Air Toxics	Meet 1990 CAAA* regulations

* Clean Air Act Amendment.

the commercialization of coal-based advanced power generation depends, in some measure, on the success of emerging second- and third-generation systems.

The second-generation systems that are the principal focus of this report are IGCC and PFBC designs entering their demonstration phase of development. These are represented by the four PFBC and six IGCC demonstration projects listed in Table 9, which are included in the U.S. Clean Coal Technology Program (U.S. DOE, 1994). Technical advances in PFBC involve moving beyond high-efficiency cyclones and hardened turbines to the use of ceramic barrier filters for particulate removal and topping combustors fueled on coal carbonization gas for raising gas turbine operating temperatures (Dellefield and Reed, 1992). The six IGCC demonstrations involve different combinations of air- or oxygen-blown gasification along with either hot- or cold-gas cleanup for particulates and H_2S and combustion control for NO_x. The gasifier types represented are entrained flow (Texaco, Destec, and ABB-Combustion Engineering), fluidized bed (Kellogg and TAMCO), and slagging fixed bed (British Gas/Lurgi).

Process parameters for the above technologies and other designs under development are summarized in Table 10. The interactions of LRC properties with these generic PFBC and IGCC processes are evaluated in the following sections. Coal property impact on alkali gettering, hot particulate filtration, air toxic controls, and solid residual management, which are common to all advanced systems, are discussed separately.

5.2.1 Advanced PFBC Systems

Advances in PFBC involve improvements in ceramic barrier filters and the development of hybrid systems for increasing gas turbine temperatures and efficiencies. Conventional PFBC combined-cycle systems typically produce only 20%-30% of their power output from the gas turbine, which, along with low gas turbine temperature, limits efficiency and provides only a relatively small increment of added capacity in repowering applications. Hybrid systems serve to overcome these limitations.

Hybrid PFBC systems (Figure 1) offer substantial improvement in efficiency by afterburning with coal gas or natural gas to raise gas temperatures and efficiencies up to the limits

TABLE 9

Advanced Power Projects in the U.S. Clean Coal Technology Program

Project	Primary Technology Providers	Unit Capacity, MWe	Important Features
<u>Pressurized Fluidized-Bed Combustion</u>			
Tidd	Babcock & Wilcox	70	PFBC with high-efficiency cyclones and hardened gas turbines
Appalachian Power	Babcock & Wilcox	340	Compact scaleup of Tidd design with possible hot-gas filtration
DMEC-1	Pyropower	80	Circulating PFBC with ceramic barrier filter
Four Rivers	Foster Wheeler	95	Hybrid carbonizer/PFBC, ceramic barrier filter and topping combustor
<u>Integrated Gasification Combined Cycle</u>			
Springfield	ABB Combustion Engineering	65	Air-blown entrained-flow gasifier with moving-bed hot-gas cleanup
Camden	British Gas/Lurgi	240	Oxygen-blown slagging fixed-bed gasifier with cold-gas cleanup and 2.5-MW fuel cell
Pinon Pine	Kellogg	102	Air-blown fluidized-gasifier with in-bed limestone, ceramic barrier filter, and metal oxide desulfurization
Toms Creek	TAMCO/IGT[1]	190	Air-blown fluidized-bed gasifier with in-bed dolomite, zinc titanate fluidized-bed hot-gas desulfurization, ceramic candle filters
Tampa Electric	Texaco/GE	322	Oxygen-blown entrained-flow gasifier with parallel cold-gas cleanup and zinc titanate fixed-bed hot-gas cleanup, advanced gas turbine with N_2 injection for NO_x control
Wabash River	Destec	262	Oxygen-blown two-stage entrained-flow gasifier with heat exchangers for steam generation and fuel gas reheat after cold-gas cleaning

[1] Institute of Gas Technology.

TABLE 10

Process Parameters for Second-Generation Advanced Power Systems

	Combined Combustion Cycles			IGCC			
	Advanced PFBC	Direct-Fired Slagging	Externally Fired Comb. Cycle	Moving-Bed Dry Ash	Moving Bed Slagging	Fluidized Bed	Entrained Flow
Process Developers	Foster Wheeler Babcock & Wilcox ABB-Pyropower	Avco/Westinghouse Solar Turbines	United Technologies Foster Wheeler Hague International	Lurgi	British Gas/ Lurgi	TAMCO/IGT HT-Winkler Kellogg	Texaco (oxygen) Dow (oxygen) Shell (oxygen) Prenflow (oxygen) CE (air)
Coal Conversion Conditions							
Pressure, atm	10-20	10-20	1-20	10-20	10-20	10-20	10-20
Max. Temperature, °C	800-900	1500-1600	1500-1600	1100-1300	1500-1600	800-900	1300-1700
Exit Gas Temperature, °C	800-900	1000-1350	1200-1400	200-600	200-600	800-900	1000-1400
Gas Atmosphere	Oxidizing	Reducing/oxidizing	Oxidizing	Reducing	Reducing	Reducing	Reducing
Key Technical Issues	Bed agglomeration SO_2 removal eff. Sorbent utilization Sulfide oxidation Alkali gettering Barrier filters NO_x control	Slag removal eff. Sulfur control method Alkali gettering Barrier filters Materials corrosion NO_x control	Slag control Ceramic heat exchanger design Materials corrosion NO_x control	Coal fines High steam req. Tar separation Low offgas temp. Hot-gas cleanup High NH_3 NO_x control	Slag discharge Tar separation Hot-gas cleanup	Carbon conv. Char recycle In-bed sulfur cont. Alkali gettering Barrier filters	Coal feeding Air operation High offgas temp. Heat recovery Oxygen demand Alkali gettering Hot-gas cleanup
Priority Gas Contaminants							
Hot-Gas Cleanup Tar Cracking Ceramic Barrier Filters Metal Oxide Desulfurization	Particulates Alkalies	Particulates Alkalies H_2S/SO_2		Coal dust Tar H_2S	Coal dust Tar H_2S	Char Tar H_2S Particulates Alkalies Chlorides	H_2S Particulates Alkalies Chlorides
Auxiliary Emission Controls							
NO_x	CC[1] or SCR[2]	CC or SCR	CC or SCR	TCC[3] or SCR	TCC or SCR	TCC or SCR	TCC or SCR
Sulfur	In-bed limestone	Sorbent injection	Scrubber			In-bed limestone	
Particulate			ESP or baghouse				
Air Toxics	Char filter	Char filter	Char filter			Char filter	Char filter

[1] Combustion controls for NO_x reduction.
[2] Selective catalytic reduction for NO_x control.
[3] Turbine combustion control for NO_x control.

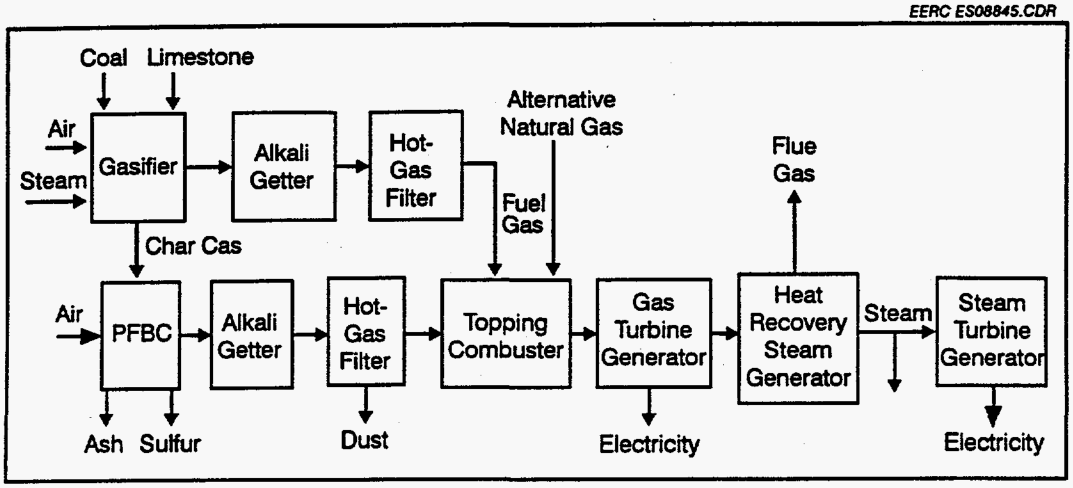


Figure 1. Hybrid PFBC combined cycle.

imposed by the gas turbine (Dellefield and Reed, 1992). This decoupling of the gas turbine temperature also allows flexibility for reducing the bed temperature in the PFBC when operating on high-alkali LRCs, to reduce the risk of alkali vapor carryover to the turbine and agglomeration in the bed. The high reactivity of LRC maintains reasonable carbon burnout at lower bed temperatures. Alternatively, the bed temperature can be optimized for SO_2 removal and sorbent utilization.

In a hybrid PFBC system, limestone or dolomite is added to the fluidized-bed gasifier supplying fuel gas for after-burning limestone or dolomite to capture H_2S as calcium sulfide (CaS). Achieving high levels of sulfur capture (e.g., 90%) in the gasifier requires operation at temperatures above 900°C to calcine $CaCO_3$ to CaO (Pitrolo and Bechtel, 1988). The reaction of calcined limestone/dolomite is rapid, and H_2S removals approach equilibrium (Abbasian and Rehmat, 1990). However, high gasification temperatures raise concern over alkali release and bed agglomeration when high-alkali LRCs are used. Also, the subsequent conversion of CaS to $CaSO_4$ in PFBC, which is necessary for safe waste disposal, may not go to completion, and some of the oxidized sulfur can be released as SO_2 in the offgas (Pham and Lawson, 1990).

5.2.2 Advanced IGCC Systems

Simplified IGCC systems designed to minimize capital cost, as depicted in Figure 2, consist of a gasifier, a hot-gas cleanup module, and the gas turbine/steam turbine power system. System configuration would be determined on the type of gasifier used, which ideally would be air-blown and match the temperature requirement of the hot-gas cleanup module. Exit gas temperatures as shown in Table 11 can vary from as high as 1400°C in the Texaco

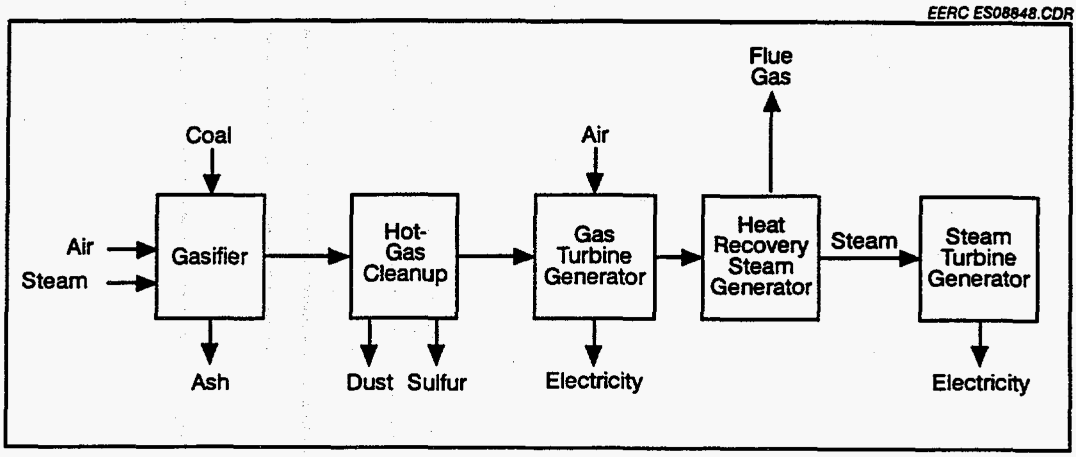


Figure 2. Simplified IGCC.

TABLE 11

Coal Property Impact on Ceramic Refractories, Filters, and Heat Exchangers

Temperatures	Low	Intermediate	High
	800°C (1500°F)	1100°C (2000°F)	1400°C (2500°F)
Properties	Alkali Chloride	Phase variability	Iron Slag viscosity
Effects	Ash adhesion Alkali/Cl corrosion Alkali-accelerated oxidation of SiC and SiN Partial reduction to volatile SiO	Slag pitting	Ion mobility Slag deposition Slag corrosion

entrained-flow gasifier down to as low as 200°C in a moving-bed gasifier operating on high-moisture lignite. IGCC is an attractive repowering technology when added generating capacity is needed owing to the relatively larger amount of power generated in the gas turbine when compared to a PFBC combined cycle.

Commercial entrained-flow gasifiers are offered by Texaco, Dow, and Shell for oxygen-blown operation. The ABB Combustion Engineering air-blown entrained-flow gasifier under development for the Springfield Project under the U.S. Clean Coal Technology Program is a two-stage gasification process that combines a tangentially fired slagging combustion section (operating on pulverized coal and recycle char) and an entrained-flow gasification section (operating on pulverized coal only), with both sections incorporated into a waterwall steam generator design (Thibeault et al., 1992). Planned demonstrations of advanced IGCC systems based on an entrained-flow gasifier with cold-gas cleanup include Tampa Electric (Texaco), Wabash River (Destec), Buggenum in the Netherlands (Shell), and Puertollano in Spain (Prenflow).

The advantages of fluidized-bed gasifiers are in their ability to incorporate in-bed sulfur capture using limestone and their reduced gas-cooling requirement. Up to 90% sulfur removal can be accomplished in the bed at temperatures above 900°C, where the limestone is substantially calcined. The use of precalcined limestone might reduce this temperature, but confirming data are not available. At best, in-bed sulfur control does not match the 99% removal capability of mixed metal oxide sorbents such as zinc ferrite or zinc titanate. Also, in-bed sulfur removal adds complexity by requiring a PFBC or other combustion unit to convert the unstable calcium sulfide waste produced in the gasifier into calcium sulfate that is suitable for disposal, as well as to make use of the unburned carbon in gasifier char. Operation of a fluidized-bed gasifier above 900°C with high-alkali coals raises concerns over bed agglomeration and increased carryover of alkali vapor into the gas turbine. High carbon conversions at low char recycle rates can be achieved at temperatures below 900°C when reactive LRCs are used, provided that a lower level of in-bed sulfur capture is acceptable. Demonstrations of IGCC based on fluidized-bed gasifiers include Pinon Pine (Kellogg) and Toms Creek (TAMCO/IGT) in the U.S. and Kobra (Winkler) in Germany.

An optimized design study on the use of moving-bed (fixed-bed) gasifiers in minimum-cost IGCC systems prepared by the U.S. DOE (Notestein and Moore, 1990), predicted that the capital costs for an n^{th} plant could be reduced to a level as low as US$700/kW. The optimum system was configured to include 1) a dry ash fixed-bed gasifier operating on air from the gas turbine compressor; 2) a dual-function fluidized bed for hot-gas cleanup, using zinc titanate for sulfur control and a zeolite catalyst for tar cracking; 3) a small limestone PFBC to serve both as a waste fuel burner and sulfur fixation reactor; and 4) the gas turbine/steam turbine combined-cycle power generators. The gas turbine compressor would provide air to both the gasifier and the PFBC unit and would accept hot flue gas from the combustion. For low-moisture or predried feed coals, the exit gas temperature from a dry ash fixed-bed gasifier approximately matches the nominal 537°C (1000°F) operating temperature of the sulfur control module. The most critical design aspects of the system concern hot-gas desulfurization and tar cracking. Replacement of the PFBC with a sulfur recovery process does not substantially increase the estimated plant cost, but it eliminates the capability for directly utilizing waste fuels, including coal fines.

The use of LRC in a minimum-cost fixed-bed IGCC system is an opportunity that deserves consideration for Czech lignites. Ten years of experience with oxygen-blown Lurgi gasifiers at the Dakota Gasification Company Great Plains Plant in the United States has demonstrated their suitability for U.S. lignites (Miller and Lang, 1988). Lurgi-type gasifiers built by the Czech company ZVÚ Hradec Králové and used by the Sokolov Coal Company to produce city gas from lignite are currently being converted to IGCC. Principal advantages of matching this technology to lignite include 1) the noncaking property of the coal, allowing free flow through the reactor; 2) high throughput with essentially complete carbon conversion; 3) relatively low gasifier exit temperatures that eliminate concern over alkali carryover to the turbine; and 4) inherently high heat recovery achieved by the countercurrent flow of coal and gas and through the in-process use of steam generated in the jacketed gasifier shell. Technical issues related to the use of dry ash fixed-bed gasifiers include their limited ability to use friable coals or coal fines; tar separation and recycle; high ammonia yields that affect turbine NO_x emissions; and the need to match gas cleanup to the gasifier exit temperature.

Some of the limitations of dry-ash fixed-bed gasification are remedied in the British Gas/Lurgi slagging fixed-bed gasifier design. This design has not been advocated for use with LRCs by British Gas/Lurgi, even though tests performed by the U.S. DOE using North Dakota lignite in the EERC's 25-tpd oxygen-blown slagging gasifier gave good results, yielding 250 Btu/scf gas at 350°F (Willson et al., 1981). The British Gas/Lurgi gasifier has reportedly also been tested in an air-blown mode operating on a 1000°F air blast, producing 120–130 Btu/scf gas at an exit temperature higher than in a dry ash design (Notestein and Moore, 1990). The advantages of the British Gas/Lurgi gasifier include a four- to sixfold reduction in steam consumption, improved system efficiency both in the gasifier and at the plant stack (by reducing the substantial energy loss due to water vapor leaving the stack), the capability of using coal fines by injection into the high-temperature (3000°F) reaction zone, the generation of a environmentally benign vitrified slag, and a lower yield of ammonia (NH_3). Demonstration of IGCC based on the British Gas/Lurgi gasifier is planned for the Camden Clean Coal Technology Project in the United States using bituminous coal.

5.3 Underground Coal Gasification

UCG has the potential to become a technically and economically viable alternative technology for utilizing deep and otherwise uneconomically recoverable lignite seams in the Czech Republic for power generation (Sondreal and Daly, 1991). It is estimated that a UCG facility for producing fuel gas for a combined-cycle power system would represent a 10% to 20% savings in capital cost, plus a lower operating cost, than a comparable surface gasification facility (Sinor, 1992).

In its most basic form, the UCG process involves drilling two wells into a coal seam, establishing a gas flow link between the wells, igniting the seam, gasifying the coal by injecting air or oxygen and steam into one well, and removing product gas from the other well. As underground gasification proceeds, the reaction cavity grows and moves along the path between the wells. The product gas from UCG contains the same components that are obtained from a surface gasifier, including hydrogen, carbon monoxide, carbon dioxide, methane, hydrogen sulfide, and nitrogen in the case of air-blown operation; however, the gas produced by UCG may experience significantly wider fluctuations in composition and heating value than gas produced in a surface gasifier. Overburden and water (both from aquifers and from mineral hydrates) introduced from the surrounding strata into the UCG reaction zone consume some of the available energy and reduce the efficiency of energy recovery. However, with appropriate design and operational control, a high energy recovery and substantial consistency in gas flow and quality can be achieved.

A gas flow link is necessary between injection and production wells and can be established in advance of gas production either by directional drilling or by burning between the wells, using a variety of techniques. In one variation, the injection pipe is inserted in a horizontal borehole to a point close to the production well; the injection pipe is then periodically retracted during UCG operation to provide a controlled retracting injection point (CRIP) technique for the purpose of reducing heat loss and water influx into the product gas. Depending on the caking characteristics and degree of fracturing and permeability of the coal seam, reverse-combustion linking can be effective at a small fraction of the cost of horizontal drilling used in the CRIP method.

Experience has shown that a thorough understanding of the geology and hydrology of a UCG site is critical for ensuring both process integrity and environmental protection. The choice of an unsuitable coal seam, boundary strata, and/or hydrology can result in loss of product gas, contamination of groundwater, and surface subsidence. However, UCG when properly conducted at a favorable site causes less disturbance to the environment than mining.

UCG in the United States has advanced to the point of near-commercial readiness as a result of field tests performed between 1975 and 1987. During this period, more than 800 days of UCG operation were completed, gasifying mainly Wyoming subbituminous coal and Texas lignite. These tests have demonstrated that the greatest obstacle to UCG commercialization—the threat of environmental degradation, particularly groundwater contamination—can be avoided by planning and operating the UCG gasifier in harmony with the local hydrogeological conditions.

Low-rank coals have, in general, proven to be good candidates for UCG owing to their noncaking characteristic and high reactivity. The most recent UCG test in Wyoming (Rocky Mountain 1), supported by the U.S. DOE, Gas Research Institute, and others with hydrogeological support from the EERC, showed that groundwater contamination can be reduced to undetectable or insignificant levels by consistently operating the underground gasification reactor at a pressure below the hydrostatic groundwater pressure and by thorough venting after completion of module operations.

Favorable coal seam characteristics for UCG include 1) a seam thickness greater than 3 meters, 2) a depth of 100 to 500 meters, and 3) continuity over a substantial area without major faults or partings. A steeply dipping bed with these characteristics can be particularly advantageous. Overburden should have structural stability under high-temperature conditions and a sufficient bulking property to prevent subsidence. The strata in close proximity should not include additional coal seams above or below the primary seam or faults leading to the surface. Favorable hydrogeological conditions involve saturated conditions with low to moderate flow characteristics. Groundwater inflow can be managed if the local hydrologic system is known.

Underground coal gasification for power generation was carried out in Russia in the 1955-1975 time period, when a total of 12 million tons of coal were gasified. The largest operation was at the Tula station in the Moscow lignite basin. Air-blown UCG was successfully used in Russia to produce low heating value gas of approximately 110 Btu/scf, sufficient for use in a gas turbine. The data available from the Russian tests, together with other data from UCG tests performed in the United States and a number of other countries, provide a sufficient technical basis to justify a demonstration project integrating UCG with a gas turbine combined-cycle power system.

An evaluation of costs for applying UCG to North Dakota (U.S.) lignite supports the use of UCG for power generation, but underlines the need for demonstration (Sinor, 1992). This study indicated that UCG drilling costs would be about one-third of mining costs, that the capital cost of UCG without the well field would be 28% less than for a surface plant using Lurgi gasifiers, and that medium-Btu gas could be produced by UCG for 22% less than by surface gasification (US$3.17 versus US$4.08/MMBtu). Other technical and cost factors in a UCG-fueled advanced power system would include 1) methods for cleaning of the gas produced, 2) effects of gas quality variations on gas turbine operability, 3) any special gas turbine and HSRG design requirements, and 4) turndown capability.

Preliminary consideration of readily available seam depth and thickness data for Czech coalfields (Couch, 1989) indicates that lignite reserves in the Sokolov and Most regions may provide good opportunities for UCG (Schmit, 1995). The high ash content of these coals could present problems if it reflects significant partings in the coal seams. A more definitive assessment would require additional data on coal seams and related geological and hydrological factors. Further assessment could be provided with reasonable effort if relevant data were available.

5.4 Phased Construction of Gasification Combined-Cycle Plants

Phased installation of IGCC units may be financially beneficial in locations, as in the United States, where gas prices are currently low but future price escalation for gas is expected to outpace that for coal. Two subsystems of an IGCC plant, the gas turbine and the HRSG, can be used independently to provide peaking power or heat for district heating, initially using natural gas as the fuel. Later, these same subsystems, if properly designed, can be incorporated into an IGCC system to take advantage of lower coal-based fuel prices when baseload electrical requirements increase. Planning for phased construction provides enhanced flexibility in addressing load growth, fuel price and availability, environmental compliance, and financial risk. This flexibility, however, requires that some added cost will be incurred by installing subsystems that are adaptable to IGCC. The feasibility of incurring the additional cost depends on the specific circumstances of the project. The following discussion drawn from EPRI sources applies to the conversion of a gas turbine peaking unit to IGCC.

Financial benefits of phased IGCC include 1) closer matching of forecast load growth to peaking and baseload capabilities, 2) leveling of capital investment to allow greater reliance on internal financing, and 3) reducing risks due to uncertainty in load growth rates, regulatory requirements, and technological advancements.

Heavy-duty gas turbines, suitable for simple-cycle operation on natural gas and later conversion to coal-derived medium-Btu gas (MBG), are offered by General Electric, Westinghouse, Siemens, and ABB Combustion Engineering in an overall size range from 40 to over 200 MW. Advanced gas turbine designs are available with firing temperatures approaching 1300°C and with variable air inlet guide vanes to maintain high firing temperatures at partial-load operation. High firing and exhaust temperatures are important IGCC design considerations both for a high gas turbine efficiency and for an efficient steam cycle based on high superheat temperatures. Provision for extracting air from the gas turbine compressor for the gasifier oxygen plant is also desirable. Conversion of a gas turbine from natural gas to MBG firing at a minimum requires the replacement of the fuel gas manifold and some turbine nozzles and may additionally involve replacing blade or casing components and adding steam injection for NO_x control. Conversion cost can vary from under 10% to slightly over 20% of the initial gas turbine cost. Power output after conversion can be increased by up to 10%, depending on machine selection.

Selection of a steam cycle suitable for conversion to IGCC is linked to the gas turbine exhaust temperature, which could exceed 600°C (1112°F) for an advanced machine. At a high exhaust gas temperature, favorable steam conditions for an efficient reheat steam turbine would be 1800 psig and 950°–950°F (123 bar and 510°–510°C). For optimum efficiency, the HRSG should be designed to achieve a suitable balance between the lowest-possible gas–steam temperature differential measured at the evaporator "pinch point" and provisions for adequate turndown and a low gas-side pressure drop. Supplemental firing in the HRSG can be used to meet infrequent load peaks if the steam cycle is adequately sized. The HRSG also needs to be sized to preheat boiler feedwater, possibly to generate high-pressure steam for the coal gasification plant.

Some technical limitations may apply to a phased IGCC system that would either be less stringent or not exist in a plant built initially to use coal gas. Limits on the minimum heating value of fuel gas used in a gas turbine conversion would probably rule out air-blown gasification as an option. The gasifier chosen should not, ideally, be a net producer or user of steam. Use of low-level heat may be more limited, particularly if the gasification plant is physically separated from the gas turbine and the HRSG. Depending on the gas turbine design selected, power output at low ambient temperatures may be significantly reduced when coal gas is fired in place of natural gas. Greater NO_x control is needed when firing coal gas owing to higher adiabatic flame temperatures compared to those of natural gas. Any mismatch of subsystems, including the gas or steam turbine, the HRSG, and the gasifier, could seriously compromise the capacity, efficiency, and turndown of the IGCC system, limiting its usefulness as a baseload generating unit in a grid system operating with least-cost power dispatching. In reference to coal properties, limitations in selecting a gasifier for indigenous Czech lignite are discussed in the subsequent sections.

5.4.1 Hot-Gas Cleaning of Particulates

High-efficiency cyclones remove particulates down to 5–10 μm, but removal of smaller particles requires the use of either a barrier filter, a granular bed, an ESP, or a fabric filter. Fabric filters that are widely used at lower temperatures require substantial material development before they can be applied in advanced power systems. Fabric materials that can withstand significantly higher temperatures have been tested at atmospheric pressure and temperatures up to about 427°C (800°F) (Weber et al., 1990). The use of ESPs is limited by sparkover and by maintenance problems of electrical insulation at high temperatures. Granular beds may be applicable where both alkalies and chlorides need to be removed along with particulates. Ceramic barrier filters are currently the preferred choice for augmenting cyclones. Ceramic candle filters supplied by Westinghouse are being tested at the commercial scale on a slipstream at the Tidd PFBC plant, and various types of ceramic barrier filters will be included in the IGCC plants being designed under the U.S. Clean Coal Technology Demonstration Program. The filtering capabilities of pulse-cleaned candle filters have been proven at outlet dust loadings of 3–19 ppm, but surface blockage by fine ash particles remains a problem, and the desired service life has not been demonstrated. Ceramic cross-flow filters, which offer higher filtration efficiencies at lower pressure drop, are at an earlier stage of development and require improvements addressing delamination, long-term pressure drops, and service life. Certain LRCs that contain inorganic constituents primarily in organically associated form, which produce an extremely fine cohesive fly ash, will require special attention in the design of hot-gas filtration systems.

Coal property impact on ceramic components is related to the presence of alkalies, chlorides, and iron—and to slag fusion and viscosity behavior (Table 11). At lower temperatures, starting at about 800°C, alkalies and chlorides accelerate corrosive reactions (including the oxidation of silicon carbide and silicon nitride) and promote ash particle adhesion leading to filter blinding. At low-to-intermediate temperatures in a reducing atmosphere, silicate refractories can be reduced to volatile SiO. At higher temperatures of incipient ash fusion (e.g., 1100°C), a fraction of the ash is converted to a liquid phase that can cause corrosive pitting. The corrosion and deposition properties of liquid slags at still higher temperatures depend primarily on slag viscosity, with low viscosity promoting ion mobility and corrosive chemical attack.

5.4.2 Alkali-Gettering Technology

In combustion systems below about 1900°F, alkalies occur primarily as fine sulfate particulates (aerosols) or surface coatings, but under reducing conditions in gasifiers they remain significantly in the vapor phase as chloride, hydroxide, or sulfide species even at somewhat lower temperatures. Therefore, "gettering" is more important than in combustion, although important in both. Alkaline silicates form under both reducing and oxidizing conditions, allowing alkali to be removed from the gas stream and leading to possible corrosion and deposition. Currently, no fully proven method for removing corrosive alkalies and chlorides from hot fuel or flue gases has been demonstrated.

Reviews on alkali gettering (Shadman et al., 1992; McLaughlin, 1990) indicate that alkali removals up to 99%, as required to meet gas turbine specifications, are possible using suitable aluminosilicate sorbents. Bauxite removes alkalies by physical adsorption and kaolinite and emathlite by chemical fixation. The reaction product of alkali with the aluminosilicate emathlite (albite) has a melting temperature of 1000°C (1832°F); the favored high-temperature product formed with kaolinite (nephelite) melts at 1560°C (2840°F); and bauxite melts at the highest temperature of 1982°C (3600°F). Design data addressing removal kinetics and capacity are limited. Capacities in the range of 5% to 18% have been reported. For chemical fixation, alkali diffusion through a surface product is rate-limiting. Overall removal efficiencies have been shown to be increased at higher inlet alkali concentrations, at increased sorbent-to-alkali ratios, and with reduced sorbent particle size. Alkali concentrations below 20 ppbw have been demonstrated in combustion tests at Argonne National Laboratory, New York University, and Westinghouse. The reaction of alkali vapors with aluminosilicates in gasification has been suggested to be more effective than alkali sulfate particulate removal from combustion gas, although HCl produced in the gasification of high-chlorine coal has been reported to reduce the rate of alkali uptake (McLaughlin, 1990). Difficulties in accurately measuring very low alkali concentrations result in uncertainties in the interpretation of alkali behavior.

5.4.3 Fuel Gas Desulfurization

Commonly used processes for removing H_2S and other acid gases from fuel gases are categorized in Table 12 (Simbeck et al., 1993). Commercially available cold-gas processes considered for coal gasification applications involve cooling the gas to temperatures ranging from lower than −50°C to about +50°C. The cold-gas processes can reduce H_2S levels to 1–50 ppm and may also remove other unwanted compounds, including hydrogen cyanide, chlorides, organics, and volatile metals (e.g., alkalies). Extensive heat exchanger capacities are required to cool the gas and recover heat for gas reheat and steam generation, which adds

TABLE 12

Fuel Gas Desulfurization

	Cold to Hot Ambient	Hot	
Method	Solvents and chemical reagents	Mixed metal oxides	In-bed sorbents
		$ZnO-Fe_2O_3$ $ZnO-TiO_2$ Zn-SORP® METC2/6	Limestone Dolomite
Temperature	<-50°C to 50°C (-60°F to 120°F)	540°C (1000°F)	870°C (1600°F)
Sulfur Removal	98%-99.8%	99+%	80%-95%
Common Processes	Rectisol-Linde Selexol-Union Carbide Purisol-Lurgi MDEA-Dow Sulfinol-Shell	GE EnviroPower ABB Combustion Engineering METC	TAMCO Kellogg
Problems	Extensive heat exchange	Sorbent stability Attrition Deactivation Regenerability Limited removal of NH_3, HCN, Cl^-, and volatile alkalies	Lower H_2S removal Calcination of CaS
Coal Property Impact	Minimal	Chloride degradation	Excessive waste at high sulfur levels

significantly to capital cost and reduces power generation efficiency. Coal properties are not expected to impact cold processes other than by increasing capacity requirements for high-sulfur coal.

Hot-gas desulfurization processes are still under development. In-bed limestone or dolomite, as already discussed for fluidized-bed gasifiers, has the potential for removing the 80%–95% of the H_2S at temperatures above 870°C (1600°F). The primary waste product is calcium sulfide, which must be oxidized to calcium sulfate for safe disposal. Regenerable mixed metal oxide systems which operate effectively below 540°C (1000°F) can reduce H_2S levels to as low as 10 ppm and can be used either alone or as a secondary polishing step after in-bed limestone-based desulfurization (Cicero, 1994). Metal oxide sorbents are known to experience some deactivation and attrition during use and regeneration depending on their formulation and the design (fixed or fluidized bed) of the contacting reactor. Regeneration with steam and air yields a concentrated stream of SO_2 which can be converted to elemental sulfur or sulfuric acid. Hot-gas desulfurization processes do not substantially remove ammonia, chloride, or other trace contaminants. Coal chlorides can react with metal oxides to accelerate degradation. High makeup rates of limestone or metal oxide usage could add significant costs, particularly for high-sulfur coals.

5.4.4 Solid Residuals – Reuse or Disposal

New power systems involve undefined requirements for disposal or reuse of solid wastes. Combustion fly ash use currently accounts for almost all coal residual utilization in various applications involving cement admixture; road base stabilization; grouting around pipes, culverts, and oil well casings; and soil or waste stabilization. Potential applications involve the production of a variety of manufactured structural products. Residuals from U.S. lignites have been extensively characterized by the EERC and others in studies on fly ash, bottom ash, slag, FGD waste, and gasifier ash (Pflughoeft-Hassett et al., 1992 [includes a compendium of key references]). In the United States, ASTM protocols are adequate for characterizing engineering properties, but more complete chemical and physical analyses are needed for environmental characterization. One such area is that of leaching tests that more closely simulate the chemistry of the disposal setting. Natural pH buffering and attenuation have been shown to provide some protection against leaching contamination in certain disposal settings. Arsenic and selenium are effectively attenuated by pH buffering in clayey soils; lead and cadmium are precipitated as carbonates; and barium is immobilized as sulfate. Molybdenum, sodium, and residual sulfate remain mobile. The disposal setting should be above the groundwater table and protected from hydraulic recharge. The ash itself can contribute to good disposal design, where, for example, permeability is reduced by the cementitious properties of ash or FGD waste. The key to managing a new type of residual is to be able to predict, in advance, what its behavior will be in disposal or reuse settings, based on a fundamental scientific understanding of the material, the setting, and their interactions.

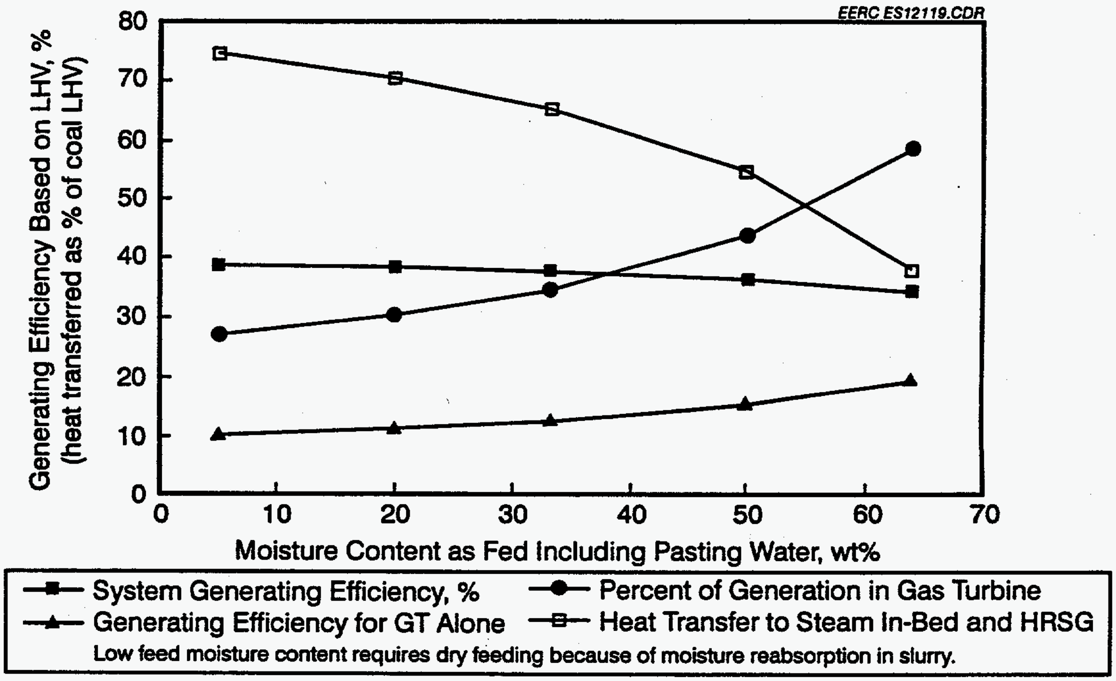
5.5 Computed Effects of Czech Lignite Properties in Advanced Power Systems

As part of this study, material and energy balances were calculated to determine the sensitivity of PFBC and gasifier performance to changes in coal properties. These calculations were performed for generic designs, and some of the conditions calculated may be outside of the range of feasible or economic operation. The computed results need to be compared with information obtained from vendors to determine the limits of applicability of various technologies.

Effects of coal moisture, ash, and sulfur were calculated for PFBC and several gasifiers, including fixed-bed, fluidized-bed, and entrained-flow designs. All calculations were made by varying the coal analysis in reference to a baseline case analysis for a high-quality Czech lignite from the Bílina mine containing 31.3% moisture, 7.3% ash (dry basis [db]), and 1.17% sulfur daf (see Table 1). Based on the range of variability reported to Czech lignites, calculations ranged up to 50% moisture, 40% ash db, and 6% sulfur daf. Base-case gasifier operating conditions and product gas compositions were adapted from literature sources (Simbeck et al., 1993; Miller and Lang, 1988) and EERC equilibrium calculations. Hydrogen, carbon, oxygen, nitrogen, sulfur, and ash were mass-balanced in all calculations, along with calcium sorbent and waste products in the case of PFBC. Operating conditions for PFBC were adapted from the Tidd Clean Coal Technology project (Hafer et al., 1993), using a gas turbine inlet at 860°C (1580°F) and 175 psia (11.9 atm) and steam conditions of 538°C (1000°F) and 2000 psi (136 atm).

5.5.1 The Effect of High Coal Moisture, Ash, and Sulfur in a PFBC

The calculated effect of increasing coal moisture (Figure 3) over a range of 0% to 50%, or up to 60% including pasting water for slurry feed at higher moisture levels, was to increase



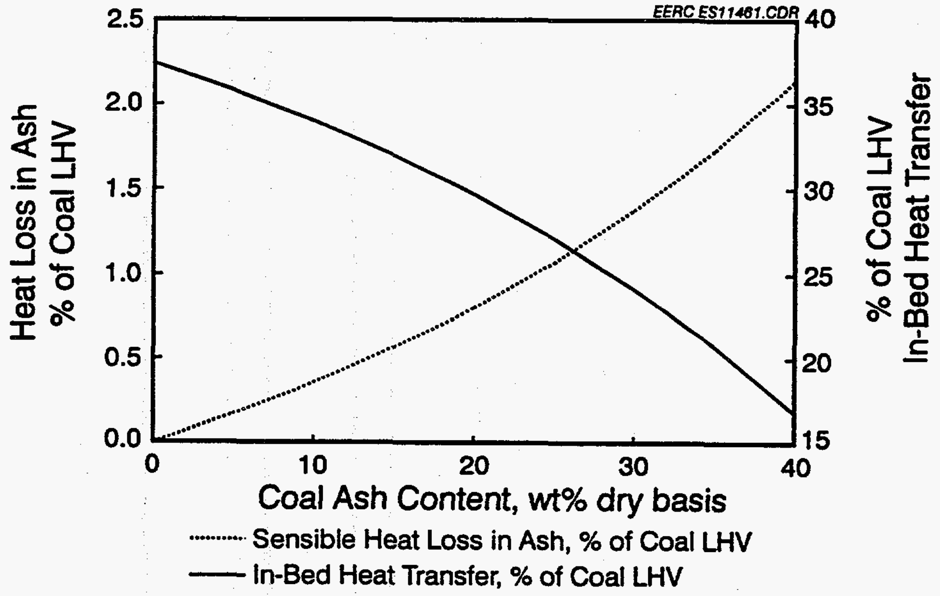
Low feed moisture content requires dry feeding because of moisture reabsorption in slurry.

Figure 3. Computed effect of moisture in coal feed on PFBC performance, as calculated for Maritsa East Bulgarian lignite.

the percentage of system power generated by the gas turbine from 29% to 46% while reducing in-bed heat transfer from 59% to 36% of coal LHV, and total steam generation both in-bed and in the HRSG from 74% to 53% of coal LHV. Generating efficiency LHV drops from 39.7% at 0% coal feed moisture (dry feed) to 37.9% at 60% moisture in slurry feed, indicating that higher stack losses due to excess moisture are only partially compensated by the beneficial shift in energy flow through the gas turbine.

Heat loss in the PFBC bed drain increases along with coal ash content up to 2.0% of coal LHV at 40% db ash content (Figure 4). The in-bed heat transfer as a percentage of coal LHV was shown to be further reduced by high coal ash levels. Thermal loss in the bed drain was only slightly affected by coal sulfur content (0.3% loss at 6% coal sulfur and 3:1 Ca:S) because of the nearly neutral enthalpy effect of limestone addition under conditions of a high partial pressure of CO_2, where the unreacted reagent remains in the form of calcium carbonate rather than calcium oxide. In the PFBC, nearly full benefit is obtained from the heating value in coal sulfur, whereas in IGCC, where hydrogen sulfide is removed, most of this heating value is either lost or recovered as low-grade heat.

SO_2 removals required to meet the Czech emission standard of 500 mg/scm applying to power plants larger than 300 MW by December 1998 range from 76% to 96% for coals containing 1%–6% daf coal sulfur. The 96% removal level is at the upper limit of PFBC



Coal moisture is 56.77% and sulfur is 5.89% daf.
Simulation is run for slurry feed with 20% pasting water.

Figure 4. Computed effect of coal ash content on heat loss and in-bed heat transfer, as calculated for PFBC of Maritsa East lignite.

sulfur removal capability. These heat and material balance calculations confirm that PFBC technology is suitable for Czech lignites at high levels of moisture, ash, and sulfur. Operational capabilities including turndown will need to be evaluated by vendors of PFBC systems.

5.5.2 Impacts of High Coal Moisture, Ash, and Sulfur on IGCC

The applicability limits of IGCC technology to Czech lignite are determined primarily by the gasifier chosen. Criteria for determining the applicability of different types of gasifiers may concern 1) achieving a minimum calorific value in the gas of approximately 100 Btu/scf or higher, 2) minimizing oxygen demand to limit the cost of the oxygen plant, and 3) maintaining operable temperature levels in the gasifier or in the exiting gas.

Calculations were performed for entrained-flow fluidized-bed and moving or fixed-bed gasifiers of the following types:

- Entrained flow
  - Shell-type dry feed
  - Destec-type two-stage slurry feed

- Fluidized bed
  - Oxygen-blown as offered by TAMCO/IGT, Kellogg, and high-temperature Winkler (HTW)
  - Air-blown

- Moving bed
  - Lurgi-type dry-ash oxygen-blown
  - BGL-type slagging oxygen-blown

5.5.2.1 Moisture

For a dry-feed oxygen-blown entrained-flow gasifier, computed effects of coal moisture (Figure 5) indicate that the LHV of the raw product gas without H_2S is reduced from 306 Btu/scf at 0% coal moisture to 137 Btu/scf at 50% moisture. Oxygen demand is increased by 46% from 0.41 to 0.59 mol O_2/mol C over this range of coal moisture contents. Since it is more economical to dry coal using low-grade heat outside of the gasifier than to supply additional oxygen, the economic range on coal moisture may be on the order of 5% to 10%.

The impact of coal moisture tends to be greater in slurry-feed entrained-flow gasifiers because of the excess water added in preparing the slurry. Calculations for a two-stage, slurry-feed Destec-type gasifier, are shown in Figures 6 and 7. The effect of adding slurry water is to lower the heating value of the raw gas over the range of 0% to 50% coal moisture by between 49-36 Btu/scf, as compared to a dry-feed gasifier. However, the oxygen requirement is substantially the same for these two gasifier types because of the offsetting advantage of two-stage feeding. In slurry-feed gasifiers, the economic benefits of drying the feed coal cannot be obtained by conventional drying since the dried product reabsorbs moisture when slurried. Hydrothermal drying in steam or hot water expels coal moisture irreversibly and can be used to improve the energy and material balance requirements of slurry-feed gasifiers.

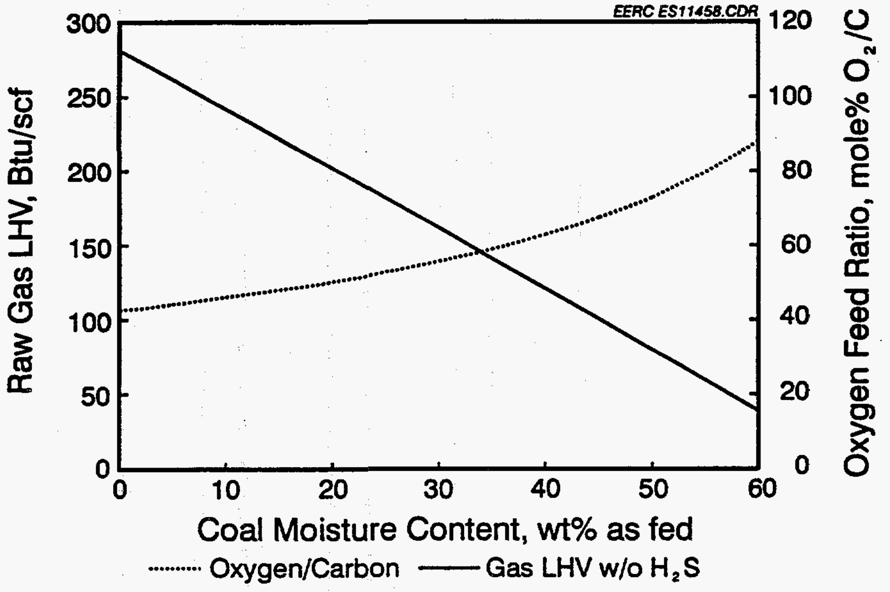
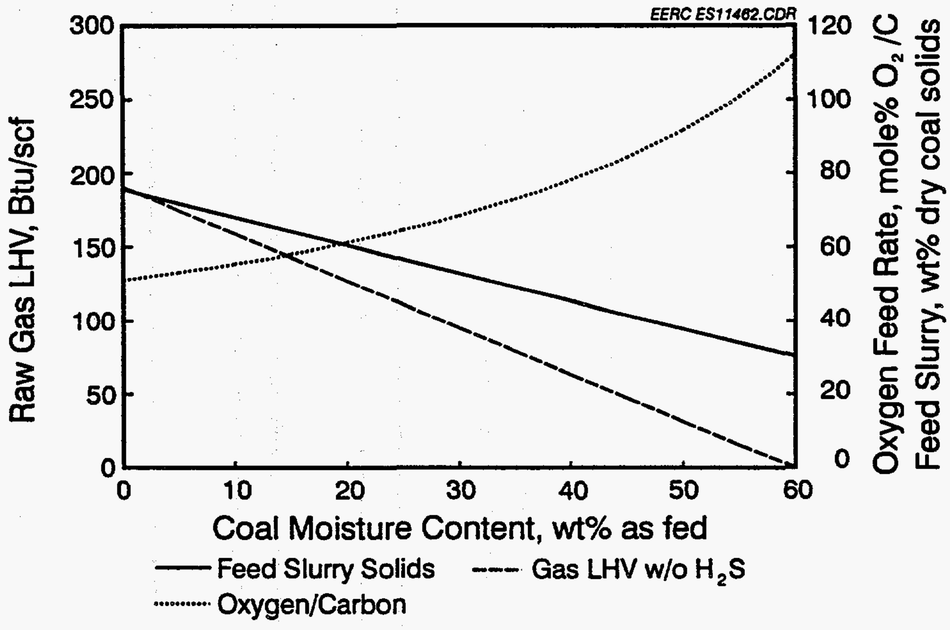


Figure 5. Computed effect of coal moisture in a dry-feed entrained-flow gasifier calculated for Czech lignite from the Bílina mine at 1371°C (2500°F) exit temperature.



Calculated for conditions resembling a Texaco gasifier.

Figure 6. Computed effect of coal moisture in a single-stage slurry-feed entrained-flow gasifier (Texaco type), as calculated for Czech lignite from the Bílina mine at 1371°C (2500°F) exit temperature.

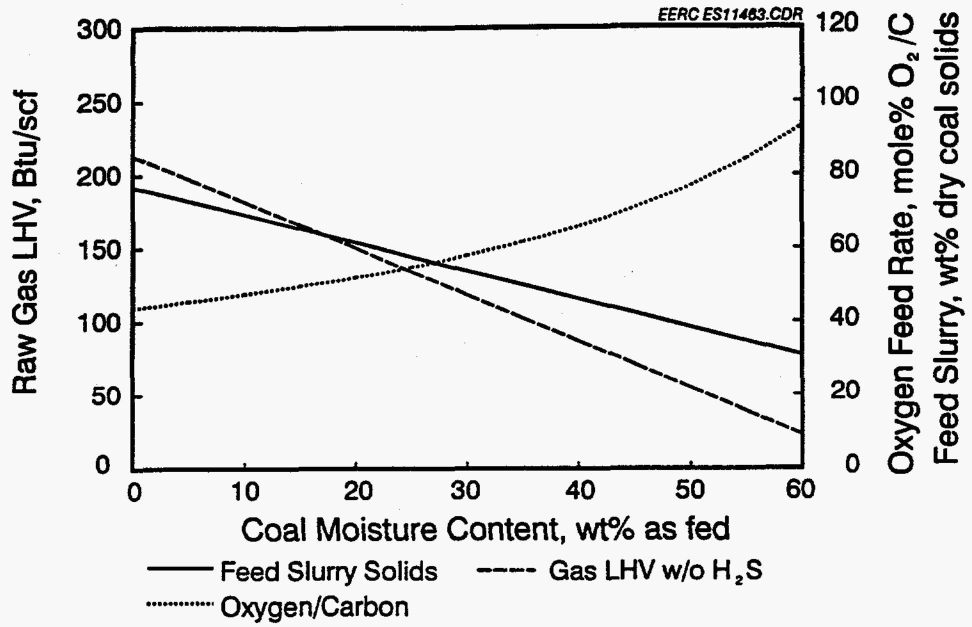


Figure 7. Computed effect of coal moisture in a two-stage slurry-feed entrained-flow gasifier (Destec type), as calculated for Czech lignite from the Bílina mine at 1038°C (1900°F) exit temperature.

Sensitivity to coal moisture content is reduced in an oxygen-blown fluidized-bed gasifier (Figure 8) compared to the entrained-flow case. The oxygen requirement, which is lower overall for this case, increases only slightly from 0.31 to 0.34 mol O_2/mol C between 0% and 20% coal moisture and raises to 0.45 mol O_2/mol C at 50% coal moisture. Drying to 20% coal moisture may represent an economic optimum for this technology. The steam requirement of the gasifier is theoretically reduced to zero at above 30% coal moisture, which is the as-received moisture level in Bílina lignite. The heating value of the raw gas is only slightly affected by coal moisture content below this 30% moisture level (Figure 9). In an air-blown fluidized-bed gasifier, the gas heating value (LHV) is reduced to the minimum acceptable level of 100 Btu/sfc at 40% coal moisture (Figure 9).

The effect of coal moisture in a Lurgi-type dry-ash moving-bed gasifier is evidenced by the exit gas temperature (Figure 10), which drops from 731°C to 236°C between 0% and 50% coal moisture. This calculation for Bílina lignite indicates a higher range of exit gas temperatures in relation to coal moisture content than for other lignites investigated, owing to the relatively higher carbon and hydrogen contents in the daf Bílina analyses. For example, the Dakota Gasification Company Great Plains Plant was designed for North Dakota lignite coal at 34% moisture. U.S. lignite is estimated to operate at an exit gas temperature of 230°C. Over the entire range of coal moisture, the oxygen and steam requirements of the Lurgi-type gasifier remain fixed, and the gas heating value is reduced only by the diluting effect of the moisture in the raw product gas. This type of gasifier requires a high steam rate which is computed to be

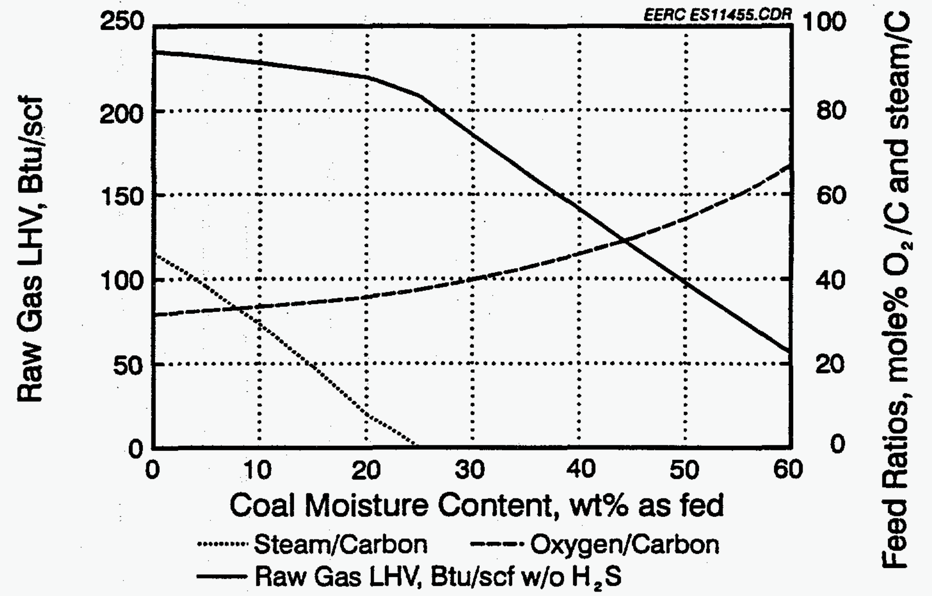


Figure 8. Computed effect of coal moisture in an oxygen-blown fluidized-bed gasifier, as calculated for Czech lignite from the Bílina mine at a constant 927°C (1700°F)

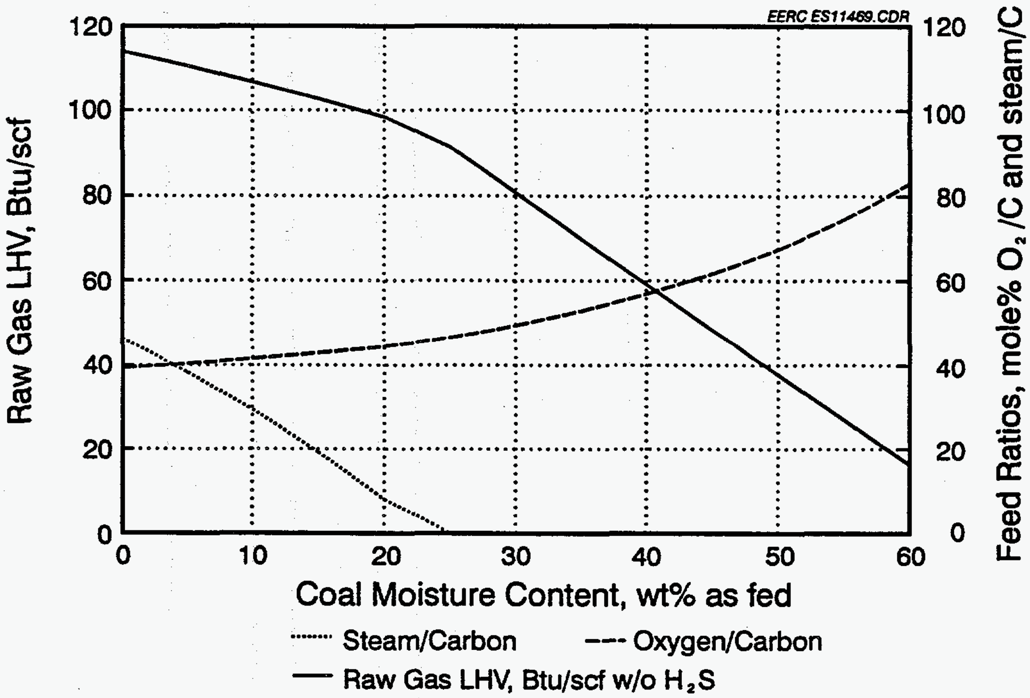


Figure 9. Computed effect of coal moisture in an air-blown fluidized-bed gasifier, as calculated for Czech lignite from the Bílina mine at a constant 927°C (1700°F) gasifier temperature.

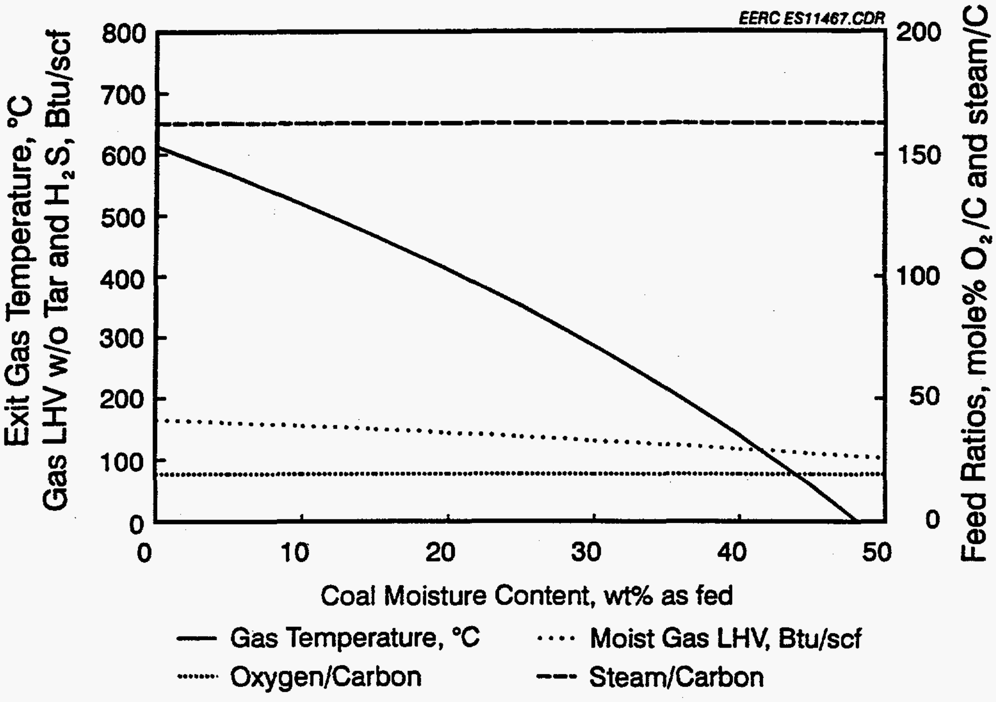


Figure 10. Computed effect of coal moisture in a dry-ash moving-bed gasifier (Lurgi type), as calculated for Czech lignite from the Bílina mine at 35% ash content (db).

150% (steam/carbon) for Bílina lignite. The operating characteristics of a moving-bed gasifier may make it more tolerant of variations in coal quality and less sensitive to turndown. The suitability of a lignite feed depends on the adequate strength to support the moving bed or, for friable coal, on the feasibility of producing a strong briquette.

The slagging moving-bed gasifier developed by British Gas/Lurgi operates at a slightly higher oxygen rate and a much lower steam rate (about one-fifth) compared to a dry-ash moving-bed gasifier. The raw gas LHV from the slagging gasifier is between 40 and 100 Btu/scf higher because of a lower dilution with steam (Figure 11). The gasifier exit temperature changes more with variations in coal moisture in the slagging design because of the reduced mass flow absent the excess steam. However, at the nominal 30% moisture level in Bílina lignite, the exit gas temperatures are similar for the slagging (563°C) and dry-ash (491°C) gasifier types.

5.5.2.2 Ash

The effect of high coal ash content based on heat loss in ash alone is far less than the effect of high coal moisture. The heat loss in ash or slag at 20% ash content is calculated to be 1.0%, 2.2%, and 3.0% for dry-ash fixed-bed, fluidized-bed, and dry-feed entrained-flow

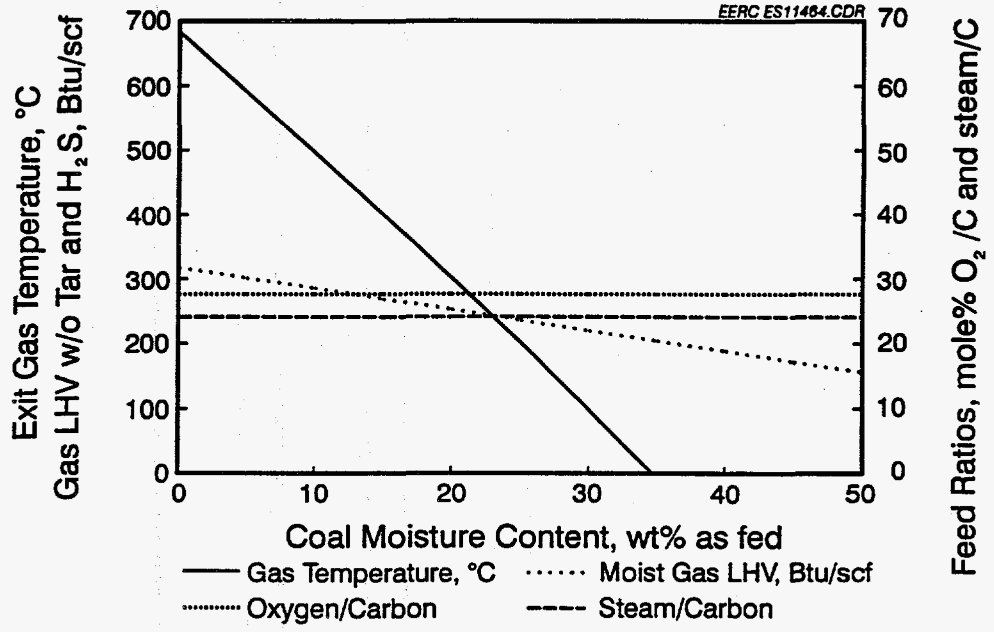


Figure 11. Computed effect of coal moisture in a slagging moving-bed gasifier (BGL type), as calculated for Czech lignite from the Bílina mine at 35% ash content (db).

gasifiers, respectively, reflecting differences in ash–slag discharge temperatures. These losses may be reduced if heat is recovered. However, the effect of ash content on the mass and energy balances also depends on the associated moisture content. In an oxygen-blown fluidized-bed gasifier at 30% coal moisture, the raw gas LHV is reduced by 49 Btu/scf over the range of 0% to 40% ash, while at 0% moisture the gas LHV is reduced by only 8 Btu/scf. This ash impact can be attributed to the moisture associated with the added ash.

A more serious effect of high ash content would be experienced in a fluidized-bed gasifier if gasification carbon loss increases along with ash content, as reported by Gavor et al., 1992. Based on experimental data for five Czech coals, the percentage of unburned carbon in the ash solids increased linearly with coal ash contents, as shown in Figure 12, from 10% carbon in ash solids at 5% ash content to 30% carbon in ash solids at 23% ash. Based on this correlation, the heat loss in unconverted carbon (including the heating value in the lost carbon) was computed to increase from zero to 56% of the coal LHV at a coal ash content between 0% and 40% in Bílina lignite. Gavor reported a 36% heat loss at 23% coal ash content calculated for a different set of conditions (Gavor et al., 1992). The gasification of high-ash coal would not be feasible under these circumstances. However, compensating operational changes in gasification temperatures and recycle rates may be capable of offsetting such unacceptably high carbon losses.

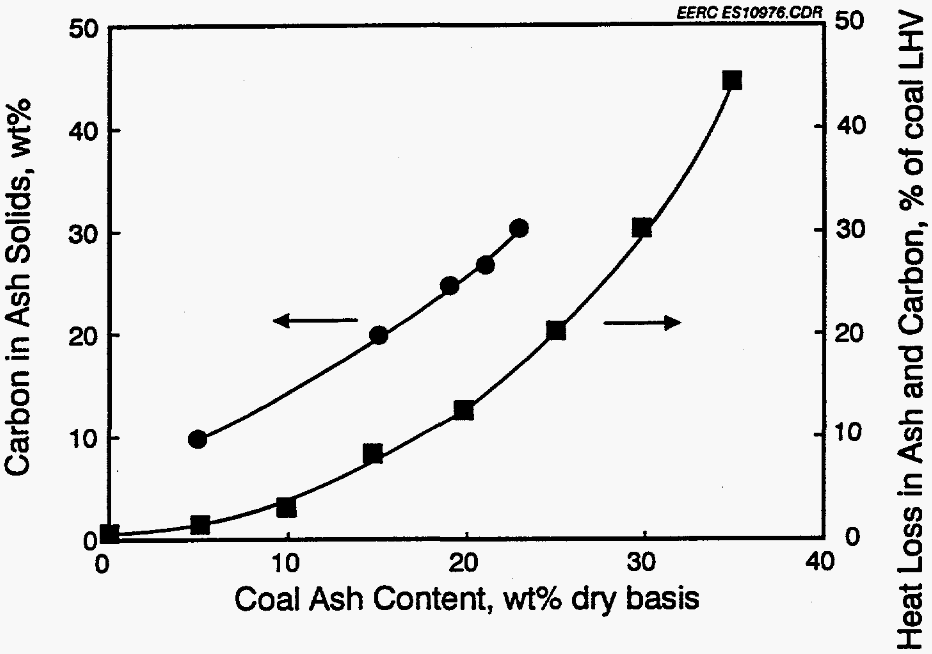


Figure 12. Heat loss in ash and unconverted carbon in a fluidized-bed gasifier, based on a correlation of carbon loss with ash content (Gavor and others, 1992).

5.5.2.3 Sulfur

The concentration of H_2S in the moist raw product gas increases from 0 to 13,800 ppmv between 0% and 6% daf sulfur for an oxygen-blown fluidized-bed gasifier fueled on Bílina lignite. The heating value of this H_2S, which is substantially lost in gas cleaning, ranges up to 3.5% of the raw gas LHV. Higher percentages of gas LHV would be lost under gasification conditions requiring higher oxygen rates (e.g., high moisture) because of the reduced heating value of the gas produced.

5.5.3 Information on Vendor Technologies

In performing an assessment of advanced power technologies for Bulgarian lignites (Energy & Environmental Research Center, 1995), requests were directed to leading vendors to obtain evaluation of their technologies applicable to the properties of the East Central European lignites. The names and addresses of vendors contacted are indicated in Table 13. While the responses were directed toward Bulgarian lignite in particular, they have general application to Czech lignite also.

TABLE 13

U.S. Companies That Have Expressed Interest in Advanced Power Systems Projects in Central Europe

Mr. David L. Breton
Manager
Process Systems
DESTEC Engineering, Inc.
2500 City West Boulevard, Suite 150
PO Box 4411
Houston, TX 77210-4411
Phone (713) 735-4249
Fax (713) 735-4735

Mr. Mike Mensinger
Institute of Gas Technology
1700 South Mt. Prospect Road
Des Plaines, IL 60018
Phone (708) 768-0602
Fax (708) 768-0600

Mr. Alex Wecksler
Lurgi Corporation
West 115 Century Road
Paramus, NJ 07652
Phone (201)967-3186
Fax (201) 967-7646

Mr. Matt Packbier
Herbts Uhde Corporation
30 S. 17th Street
Philadelphia, PA 19103
Phone (215) 422-3257
Fax (215) 422-4534

Mr. Otto Koenders
Shell International Petroleum Company
Hague Netherlands
Department MFT G7
THE NETHERLANDS
Phone 011 31 703771467
Fax 011 31 703772779

Mr. Ed Gerstbrein
Licensing Manager for Foreign Gasification Technology
Texaco
2000 West Chester Avenue
White Plains, NY 10650
Phone (914) 253-4326
Fax (914) 253-7744

Mr. Francis Lau
Institute of Gas Technology
1700 South Mt. Prospect Road
Des Plaines, IL 60018
Phone (708) 768-0592
Fax (708) 768-0600

Mr. Heinz J. Keller
Uhde GmbH
Friedrich-Uhde-Str. 15
D-4600 Dortmund 1/FRG
GERMANY
Phone 011 49 237 547 2718
Fax 011 49 234 547 3382

Mr. Henry Vroom
ABB Combustion Engineering, Inc.
1000 Prospect Hill Road
Windsor, CT 06095
Phone (203) 285-9085
Fax (203) 285-2099

Mr. William M. Campbell
Manager
Clean Coal Technologies
M.W. Kellogg Company
601 Jefferson Avenue
PO Box 4557
Houston, TX 7210-4557
Phone (713) 753-2184
Fax (713) 753-6609

The gasification projects considered in the Bulgarian assessment were indicated to be most likely in the last stage of a phased scenario starting with installation of natural gas-fired single-cycle turbines for peaking capacity and followed by conversion to IGCC when the need for baseload capacity increases and the price of natural gas escalates. Modular unit capacities were expected to involve 160-MW gas turbines and related steam turbine, gasification, and gas-cleaning capacities. The gasification facilities were expected to be installed after the year 2000, when simplified IGCC systems based on hot-gas cleaning methods will be commercially powered.

5.5.4 The Shell Gasifier System

The Shell gasification and cold-gas cleaning system consists of a dry-feed, oxygen-blown, entrained-flow gasifier followed by a syngas cooler, wet scrubber, and cold-acid gas absorption unit (the Sulfinol process was used at Shell's Deer Park, Texas, demonstration plant). This configuration was demonstrated on Texas lignite at a capacity of 400 short tons/day, where it achieved a carbon conversion of 99.77%, a cold-gas efficiency of 80.3% (HHV), and a total energy recovery (gas plus steam) of 95.7%. Sulfur control levels of 99% can be achieved with cold-gas absorption, with conversion to salable sulfur in a Claus-type unit. Shell's estimate of capital cost for a 2 × 400-MWe IGCC plant is US$1500/kW to US$1600/kW. Projected efficiencies are 42% to 46% (LHV), depending on coal quality and turbine efficiency. Hot-gas cleanup is estimated to improve efficiency by 1.3 percentage points, with no estimate given for the change in capital cost. A 250-MWe IGCC plant based on Shell technology has been built by Demkolec in the Netherlands and is now starting its demonstration period.

Shell provided a separate set of material balances for Maritsa East Bulgaria lignite covering four plant areas: 1) coal milling and drying, 2) gasification, 3) wet scrubbing, 4) gas and water treatment (Energy & Environmental Research Center, 1995). Lignite is first pulverized and dried to 5% moisture and then fed to the gasifier at a O_2/C mole ratio of 0.283 (lower than the 0.44 ratio calculated by the EERC). Raw product gas at 110 bar is cooled to 235°C in the syngas steam generator and then wet-scrubbed at 40°C. The cold-gas efficiency is calculated to be 89.8% (LHV) and 73.1% (HHV).

The principal advantage of the Shell gasifier for lignite is the dry coal feed, which allows thermally dried coal to be fed without reabsorbing water in a slurry preparation step. This feature is shared by the Prenflow entrained-flow gasifier that will be used at a 335-MWe IGCC plant being built at Puertollano, Spain. With cold-gas cleaning, these technologies provide a medium-Btu gas that would permit conversion from natural gas to coal gas with reasonable modifications. The high gasifier exit temperature of 1371°C (2500°F) makes the technology less attractive for simplified IGCC designs based on hot-gas cleanup because of the substantial gas cooling required to match a hot metal oxide sulfur removal system.

5.5.5 The Texaco Gasifier System

The Texaco gasifier design is an oxygen-blown, single-stage entrained-flow gasifier that uses a coal slurry feed containing approximately 25% pasting water. Raw product gas leaving the gasifier at 1371°C (2500°F) is cooled using either a fuel heat recovery system or is water-quenched followed by partial heat recovery. Capital costs for a 250-MWe Texaco IGCC plant operating on U.S. bituminous coal and using a cold-acid gas removal process are estimated to be US$1446/kW with full heat recovery and US$1300/kW with a water quench (Weissman, 1994). Plant efficiency is reduced when the quench option is used. Texaco gasifiers have been demonstrated to operate successfully on a wide range of carbonaceous fuels, including bituminous and subbituminous coal, heavy oil and refinery residues, petroleum coke, mixed-plastic wastes, and sewage sludge.

The high moisture content of lignite precludes its direct use in a Texaco gasifier owing to the substantial increase in oxygen required to evaporate excess coal moisture in the slurry feed. Based on the heat and material balance calculations for a Texas lignite (Energy & Environmental Research Center, 1995), the oxygen requirement expressed as moles O_2/C increases by 41% as coal moisture increases from 10% to 40%. The gas heating value is correspondingly reduced from 229 to 156 Btu/scf for dry product gas and from 159 to 63 Btu/scf for moisture product gas.

Predrying the lignite feed would be far more economical than increasing oxygen to the gasifier if moisture were not reabsorbed when slurrying the coal. However, the equilibrium coal moisture content (as a measure of the intrinsic moisture in the slurried coal particulate) is only slightly reduced by gas drying in a rotolouvre- or entrainment-type dryer, from 33% to 29% moisture content for a U.S. lignite and from 26% to 22% for a U.S. subbituminous coal. For this reason, conventional gas drying methods are not of practical use in this application.

Predrying in steam or in hot water has been shown to reject water irreversibly to produce a concentrated coal slurry with up to 63% dry solids content. An evaluation of hydrothermal dewatering of coal feed for a Texaco gasifier sponsored by EPRI confirmed that hot-water drying produced a pumpable slurry with a suitable solids loading and viscosity (Energy & Environmental Research Center, 1995). Subsequent studies performed independently by the EERC and Texaco have shown a broad technical applicability of this approach for a wide range of high-moisture coals, including brown coals containing up to 60% moisture, and for a combination of coal and sewage sludge or municipal waste.

The cost of hot-water drying is a recognized barrier to be overcome if this technology is to be adopted in IGCC applications. The added capital cost would be substantially reduced by integrating the drying process into the design of the power system. Preliminary cost calculations for modifying the existing slurry preparation system for a Texaco gasifier indicate an incremental capital cost of US$152 to US$176/kW for a 250-MW IGCC plant, depending on the method used to reject water and concentrate the slurry (Anderson, 1995).

5.5.6 The Destec Gasifier System

The design of the Destec gasifier is somewhat more readily adaptable to lignites than the Texaco gasifier design. The Destec system (SFA Pacific, 1993) is a two-stage, slurry-feed, entrained-flow gasifier. Feed slurry is prepared with a minimum of pasting water and heated to provide some dewatering of coal particles and lowering of slurry viscosity. About three-fourths of the slurry feed is fed to the first stage operating at 1316° to 1427°C (240°to 2600°F). The remaining slurry is injected into the second stage, from which the raw product gas exits at 1038°C (1900°F). The Destec IGCC system being used at the Wabash River

Clean Coal Demonstration Project (U.S. DOE, 1994) matches the gasifier with a heat recovery gas cooler, particulate removal, cold-gas sulfur removal, and fuel gas reheat.

The two-stage design of the Destec gasifier reduces heat recovery requirements and increases flexibility for using higher-moisture coals without hydrothermal drying, as evidenced by operation of the Plaquemine, Louisiana, gasification facility on U.S. Wyoming subbituminous coal. However, Destec has projected a 27% increase in oxygen demand (mol O_2/mol C) for Texas lignite containing 35% moisture compared to an Appalachian bituminous coal with 5% moisture (SFA Pacific, 1993). Hydrothermal drying of a lignite feed is warranted for the reasons given previously for the Texaco gasifier. The preliminary estimates of incremental capital cost for hot-water drying for a 250-MW IGCC plant are the same as for the Texaco scenario, in the range of US$152 to US$176/kW (Anderson et al., 1994).

5.5.6.1 The Tampella/U-Gas Gasification Process

The U-Gas fluidized-bed gasification process developed by IGT in the United States and licensed to Tampella Corporation in Finland will be used at the 190-MW$_e$ Tomo Creek Clean Coal Demonstration IGCC plant in the United States, and eight U-Gas gasifiers have been installed in China to supply fuel gas for coke ovens. The process feeds crushed coal ¼ in. × 0 through a lock hopper to a PFBG that incorporates a hot-ash-agglomerating zone. Normal operating conditions are 871°C (1600°F) and 290 psig (20 atm). Operation has been demonstrated with both oxygen and air. No steam is required for lignite, owing to the moisture in the lignite feed. Ash agglomerates are discharged in an essentially nonleachable vitrified form through a countercurrent heat exchanger, where they are cooled to 469°C (1200°F) by incoming gas. The high-temperature agglomerating zone provides a higher carbon conversion (e.g., 95%) with lower external char recycle than does conventional fluidized-bed gasification.

Information obtained from IGT (Energy & Environmental Research Center, 1995) identified no special problems in using lignite feed. The coal feed to the gasifier can contain 25% to 35% moisture and up to 10% fines (minus 100 mesh or 149 μm). Provisions for dry coal feed, char recycle, and ash discharge were indicated to be satisfactorily for using lignite. Hot-gas cleanup for particulates and sulfur has been investigated by IGT and Tampella, including limestone addition for in-bed sulfur removal.

The performance of the U-Gas gasifier given by IGT for Bulgarian lignite (Energy & Environmental Research Center, 1995) predicted a raw gas heating value of 111 Btu/scf for air-blown gasification at 25% and moisture content. This favorably high heating value was based on a high carbon conversion (95%), high air preheat temperature (800°F), and low exit gas temperature (1600°F). EERC calculations confirm the performance predicted by IGT for Bulgarian lignite and indicate even more favorable results for the Czech Bîlina lignite. These results indicate that the U-Gas design is suitable for use in a simplified air-blown IGCC system operating an as-received lignite at 30% moisture.

5.5.6.2 Kellogg Gasification Processes

Kellogg offers two gasification technologies: the Kellogg Rust Westinghouse (KRW) process and a new transport reactor process that is currently under development. The Kellogg company recommended the transport reactor process for Bulgarian lignite because of its ability to retain almost all of the coal energy in the product gas, absent the use of a waterwall design. This design was advanced by Kellogg as its best design for pressurized gasification or combustion of run-of-mine lignite at high moisture contents.

The transport reactor design feeds pulverized coal into a high-velocity fluidized bed operating at a velocity of 20 to 40 ft/sec (6.1 to 12.2 m/sec). High carbon conversion is achieved by recycling solids back into the reactor. The reactor operates at 927° to 1038°C (1700°to 1900°F) in gasification mode and 816° to 871°C (1500° to 1600°F) in combustion mode. The transport reactor concept is adapted from the proven design used in fluidized-bed catalytic cracking units used in the petroleum industry. Development for coal conversion has been confirmed at a scale of 2.4 tons/day at the EERC, and construction has started on a 38-ton/day pilot unit at the Wilsonville Power Systems Development Facility in Wilsonville, Alabama.

Kellogg's gasification calculations on the transport reactor process (Energy & Environmental Research Center, 1995) indicated that air-blown gasification of Bulgarian lignite at 20% moisture content would yield a raw gas heating value of only 75 Btu/scf, which is considerably lower than the values calculated by IGT and the EERC for air-blown fluidized-bed gasification (see above). However, the transport reactor design, owing to its use of pulverized coal (fines are not a problem) and its simple design, may offer future advantages in designing minimum-cost IGCC systems for lignite if operating conditions are optimized.

The KRW gasifier is similar to the Tampella/U-Gas process discussed previously. The principal difference between the processes is that KRW uses recycled product gas for improving velocity and temperature control in the critical ash agglomerating zone. The KRW gasifiers are being used at the 102-MW IGCC Pinon Pine Clean Coal Technology Demonstration plant in the United States. In Germany, Deutsche Babcock has obtained a license for marketing in Europe. The process has been operated in oxygen mode on U.S. lignites from Texas and North Dakota in a 30-ton/day pilot plant (Ostheim and Lewandowski, 1984).

5.5.6.3 The High-Temperature Winkler Process

The HTW fluidized-bed gasification process developed by Uhde GmbH together with Rheinbraum AG and Lurgi GmbH includes both 1) a 10-bar oxygen-blown bubbling-bed design generating synthesis gas for methanol production from 720 tons/day of dried brown coal and 2) a 25-bar design using either air or steam/oxygen as the gasification agent for IGCC applications. The IGCC design, which can be either a bubbling or a circulating bed, has been operated at the pilot plant scale for 9500 hr at a throughput rate of 160 tons/day. An air-blown circulating fluidized-bed HTW gasifier design is being used for the 355-MW Kobra IGCC plant being constructed in Hürth, Germany (SFA Pacific, 1993).

Uhde provided the following information on the HTW IGCC design suitable for Bulgarian lignite (Energy & Environmental Research Center, 1995). Lignite dried to nominally 12% moisture content is fed through a lock-hopper system to the lower fluidized zone of the gasifier operation at 850°C. A conditions requiring higher oxygen rates (e.g., high moisture) because of the reduced heating value of the gas produced. A gasification agent (either air or steam/oxygen) is admitted both to the lower fluidized zone and to the freeboard to gasify entrained carbon at approximately 940°C. Entrained solids leaving in the raw product gas are separated in a cyclone and fed by gravity back into the gasifier. Ash is withdrawn from the bottom of the gasifier and fed to a moving-bed cooler. No particular problems were identified for using Bulgarian lignite in the HTW gasifier. The lignite is crushed to a grain size of 4-mm maximum with fines retained in the coal feed. Beneficiation to reduce high ash content is not recommended. Measures are described for preventing ash and slag deposits in the gasifier system. High ash content is indicated to result in a reduced cold-gas efficiency, estimated to be 68%–70% for Bulgarian lignite versus 76% for German Rhenish brown coal.

Operation on air from the gas turbine compressor as the gasifying agent, compared to oxygen or oxygen-enriched air, is indicated by Uhde studies to have only a slight effect on capital investment, overall plant efficiencies, or emissions (Energy & Environmental Research Center, 1995). A dry-gas heating value of 4.8 MJ/m^3 (129 Btu/scf) is indicated for air-blown gasification of Rhenish brown coal, compared to 10.1 MJ/m^3 (271 Btu/scf) for oxygen gasification. Similar values were obtained in EERC calculations for lignite dried to 12% moisture.

Both cold- and hot-gas cleaning systems are described for the HTW gasifier. The cold-gas system includes 1) gas cooling to 260°C in a high-pressure steam generator; 2) particulate filtration using ceramic candle filters; 3) wet scrubbing for removal of alkalies, chlorides, and other trace contaminants; 4) hydrolysis of COS to H_2S; 5) desulfurization using a selective process leaving CO_2 in the gas stream; and 6) final humidification and fuel gas reheat.

Hot-gas cleaning, which is not commercially proven, was described to include the following: 1) cooling to 650°C, 2) particulate filtration, 3) treatment in a limestone/dolomite fixed bed for removal of alkalies and heavy metals, 4) metal-oxide desulfurization, and 5) final particulate filtration. The retention of NH_3 in the treated gas (absent a water scrubber) is identified as a problem affecting NO_x emissions.

The efficiency of a 310-MW IGCC (160-MW gas turbine and 150-MW steam turbine) is estimated to be 46% to 47% (LHV), without reference to a particular coal quality. Use of hot-gas cleaning is estimated to increase efficiency by about 2 percentage points. The estimated cost of the HTW gasification plant alone is estimated to be US$1129/kW for Bulgarian lignite, including coal drying, gasification, and cold-gas cleaning, but excluding power systems (Energy & Environmental Research Center, 1995).

5.5.6.4 ABB Combustion Engineering Coal Gasification

The ABB Combustion Engineering process is a dry-feed, air-blown, two-stage, entrained-flow gasifier selected for use at the U.S. DOE Clean Coal Technology IGCC (65-MW) demonstration project in Springfield, Illinois. The process was originated by Combustion Engineering in the 1970s in a 120-ton/day atmospheric pressure gasifier.

Combustion Engineering has since worked with Mitsubishi Heavy Industries in Japan on a 200-ton/day pressurized gasifier. The process is characterized by ABB Combustion Engineering as still being under development (Energy & Environmental Research Center, 1995).

The ABB Combustion Engineering pressurized gasifier operates on pulverized coal fed to two stages: both a lower combustion section and an upper reduction section. Raw product gas leaves the gasifier at approximately 1093°C (2000°F). The gas is cooled to 538°C (1000°F) and then passed through a cyclone to remove char for recycle back to the gasifier. The design planned for the Clean Coal Technology Demonstration project includes a General Electric-developed moving-bed zinc ferrite hot-gas desulfurization process.

Information received from ABB Combustion Engineering indicated the gasifier is well suited to firing lignite because of the high reactivity of lignite under gasification conditions. The only requirement specified for the feed coal is that surface moisture should be removed.

5.5.7 An IGCC System Based on a Moving-Bed Gasifier

Technical information on moving-bed gasifiers was received from both Lurgi Corporation and the Dakota Gasification Company operating the Great Plains Gasification Plant using North Dakota lignite. Lurgi advised that the slagging moving-bed gasifier developed along with British Gas (the BGL gasifier) would not be suitable for Bulgarian lignite. Lurgi indicated that its dry-ash process would be applicable for processing Bulgarian lignite, contingent on testing the stability (strength) of the coal and the properties of the ash under gasification conditions.

The Lurgi dry-ash gasifier operates by feeding lump coal (6 to 50 mm) through a lock-hopper system to replenish the moving bed and admitting gasifying agent (steam and air or oxygen) to the high-temperature reaction zone at the bottom of the bed. The countercurrent flow of coal and gas serves to dry and pyrolyze the coal and causes the pyrolysis tar and oil to be carried out with the product gas. The dust and tar removed from the raw product gas in the quench and heat-exchange system can be reinjected into the gasifier. Ash recovered through a grate at the bottom of the gasifier contains a very low carbon content (2% to 5%).

Feed coal for a Lurgi-type gasifier should be dried and screened to contain minimum fines (below 5%). The Dakota Gasification Company advised that beneficiation to reduce ash would not be recommended for lignite because of problems with dewatering and sizing the coal after cleaning. The Dakota Gasification Company identified cementitious ash as a potential problem in the wet-ash discharge system, which can be remedied by proper design. Lurgi indicated it had no experience with hot-gas cleanup for this gasifier.

6.0 ASSESSMENT OF LIGNITE-UPGRADING TECHNOLOGIES

6.1 Lignite Properties Affecting Upgrading

Various upgrading technologies are applicable to different ranks of coal and ranges of coal analyses. Representative ranges in analysis for U.S. low-rank coal regions are compared in Table 14 with ranges for East Central European brown coals and lignites. The ranges for East Central Europe include higher levels of moisture, sulfur, and ash and lower heating values. The ranges of variation in ash analysis are generally similar for Czech and U.S. coals, although some U.S. lignite ashes contain higher concentrations of sodium, calcium, and magnesium oxides.

The molecular structure of U.S. low-rank coals has been interpreted based on a broad range of analytical data, including elemental analysis, pyrolysis, extraction, controlled oxidation, instrumental Fourier transform infrared analysis (FT-IR), nuclear magnetic resonance spectroscopy (NMR), and differential scanning calorimetry (DSC) (Schobert, 1990; Knudson, 1986; Kube et al., 1984; Benson and Schobert, 1982). Idealized molecular models for low-rank coal, such as the one in Figure 13 indicate one-to three-ring aromatic clusters, a greater abundance of aliphatic and hydroaromatic carbon chains than in bituminous

TABLE 14

Variability in Properties of Low-Rank Coals by Country

	Czech Republic	Poland	Hungary	Bulgaria	Spain	Germany	U.S.
Location	Bílina Melnik Nastup Most Sokolov	Belchatow Konin Turow Adamow Rybnik	Oroszlany Matraalja Borsod	Maritsa East Sofia Bobov Dol Pernik	Teruel	Cologne Leipzig	Wyoming Montana New Mexico Texas North Dakota
Moisture, % as mined	6–55	9–55	19–48	14–62	13–24	48–63	10–42
Ash, % db	7–44	8–40	18–40	28–58	14–70	4–40	3–30
Sulfur, % daf	0.7–9	0.5–7	0.8–5	3–11	3–12	0.4–3	0.3–4
Lower Heating Value, MJ/kg	9–19	7–22	6–15	5–14	12–17	7–12	8–25
Ash Analysis, % Oxides							
SiO_2	35–50			15–65			18–63
Al_2O_3	11–25			4–32			13–25
Fe_2O_3	9–15			5–20			4–20
CaO	7–8			1–60			5–39
MgO	3–4			1–5			2–13
Na_2O	0.6–1.6			0.2–0.4			0.1–12
K_2O	0.4–1.1			0.2–0.6			0.1–2

Sources of data include papers by Brix, Couch, and Zakrzewski from the April 1992 Energy and Environment Conference in Prague; case study reports submitted by East Central European participants at the Least Cost Power Course at the EERC in 1992; coal analyses obtained from Bulgaria, Poland, and the Czech Republic for EERC studies performed in 1994; papers by Franke (1977), Stefanski (1981), and Hein (1986) from EERC Lignite Symposia; and U.S. analyses compiled by Selle in his 1986 Review of Slagging and Fouling from Low-Rank Coal.

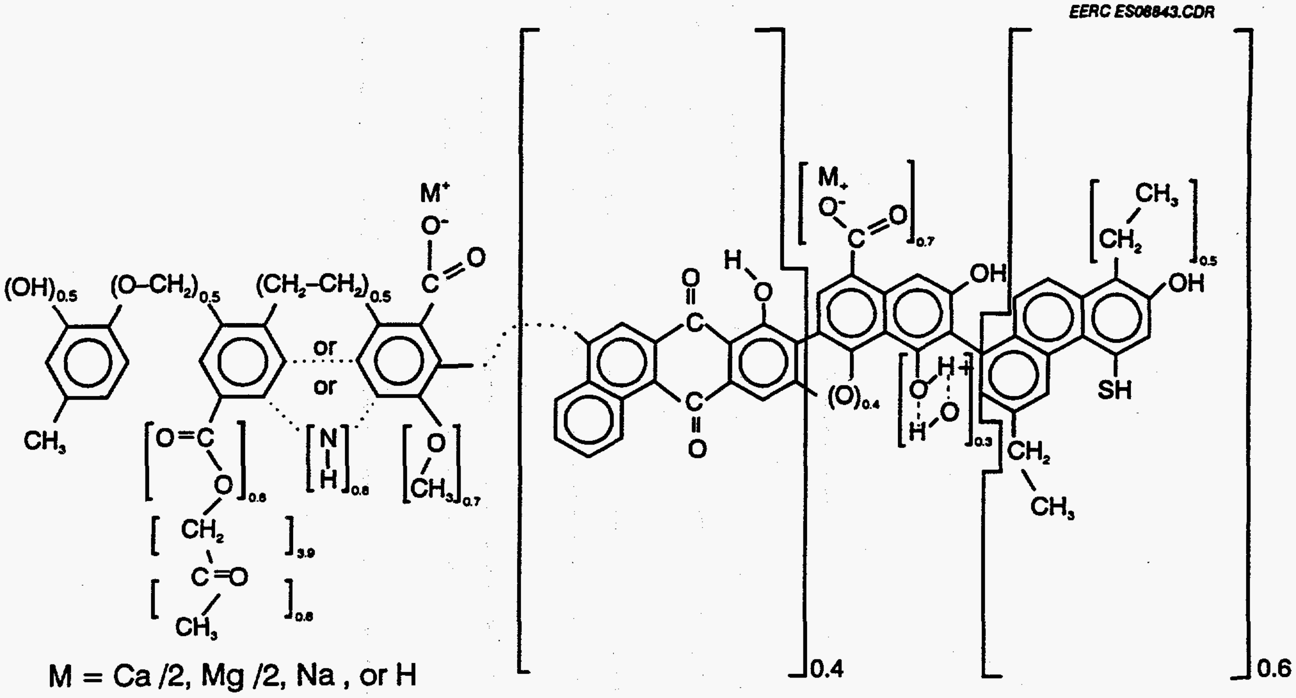


Figure 13. A molecular model for Wyodak subbituminous coal (Knudson, 1986).

coal, and a much higher oxygen content. The most important bridging groups between aromatic ring clusters are polyethylene chains (-CH_2-) and ethers (R-O-R). The atomic H/C ratio for moisture and ash-free (maf) low-rank coals is in the range of 0.75 to 0.9, which is comparable to hvA bituminous coal. Between 50% and 75% of the carbon in low-rank coal occurs in aromatic rings, compared to about 85% for bituminous coal. In laboratory calorimetry, the aliphatic and hydroaromatic carbon burns off at a lower temperature than the aromatic clusters, leaving the graphitized char.

The physical structure of low-rank coal is believed to be determined by the effect of oxygen functional groups on hydrogen bonding and the role of moisture as a structural component (Schobert, 1990). Phenolic groups provide a framework for hydrogen bonding, whereas carboxyl groups may hinder structuring. The roughly 20% of total moisture held tightly by hydrogen bonding is believed to contribute to structural rigidity in low-rank coal in the same manner as in wood, and the loss of this structure when coal is dried to low moisture levels accounts for its friability and dustiness.

The high oxygen content in low-rank coal, up to about 22% maf, includes carboxyl (-COOH)-, phenolic (Ar-OH)-, ether and methoxyl (R-O-R and R-O-CH_3)-, and carbonyl (-{C=O}-)-type functional groups. Carboxyl groups, which account for one-quarter to one-half of the total maf oxygen, are important ion-exchange sites for alkalies, alkaline earths, and trace elements. The carboxyl oxygen content thermally decomposes with the release of carbon dioxide starting above about 300°C, tending to increase the mobility of the absorbed cations in thermal processes.

The molecular form of sulfur and nitrogen in low-rank coal is not as well characterized. Their forms in pyrolysis products indicate that they occur in both aliphatic and aromatic structures. The ASTM-defined sulfur forms (pyritic, sulfatic, and organic) used in the United States have only limited value in understanding sulfur chemistry. For U.S. lignites and subbituminous coals, the ASTM determination typically indicates 50%–60% organic, 40% pyritic, and 5% sulfatic. However, research at the EERC using supercritical fluid extraction (SFE) to separate and analyze the true sulfur forms has shown that up to 36% of the ASTM "organic" sulfur is elemental sulfur (Louie et al., 1993).

High reactivities are observed for low-rank coals both in thermal processes and at near ambient temperatures where spontaneous heating begins. In high-temperature processes, reactivity is increased by the noncaking property of the low-rank coal and by the release of free radicals formed by decarboxylation. High-temperature reactivity correlates with minerals and cations that catalyze thermal reactions, but it is not directly linked to surface area measurements (Smith et al., 1993; Timpe et al., 1989). At lower temperatures, spontaneous heating correlates with reduced particle size and drying (Sondreal and Ellman, 1974).

The distribution of pore size and surface area in low-rank coals characteristically involves a relatively large microporosity scaled below 2 nanometers (nm) and a smaller macroporosity larger than 20 nm (Smith et al., 1993; Sharkey and McCartney, 1981). In higher-rank coals, this distribution tends to be reversed. The accessible pore volume increases during carbonization to form a high surface area char. Questions concerning the interpretation of surface area measurements on coal are related to the different chemical and physical gas absorption interactions that are possible.

Inorganic forms in low-rank coals are primarily categorized as either ions associated with coal carboxylate or discrete mineral grains. Most of the alkali and alkaline earth elements in U.S. low-rank coals are ionically associated, typically including 80%–90% Na, 70%–80% Mg, 60%–70% Ca, and 30%–40% K. The percentage for potassium is lower because of its occurrence in clay minerals. The major classes of minerals in U.S. low-rank coals, in approximate order of decreasing abundance, are silicate and aluminosilicate, pyrite, oxides of iron and titanium, sulfates as gypsum and barite, calcite, and phosphate as apatite (Benson et al., 1993).

6.2 Beneficiation

6.2.1 Background on Cleaning U.S. Coals

Coal cleaning is widely practiced in the U.S. to reduce the ash and pyritic sulfur contents of both metallurgical and steam coals, with most cleaning plants currently processing bituminous coal. However, cleaning has long been viewed as one key to expanding markets for low-rank subbituminous coal and lignite. Conventional gravity cleaning has been correlated with improved capacity and performance in pc-fired boilers owing to reduced erosion, mill wear, slagging, and fouling and to increased pulverizer capacity (Durant et al., 1989; Busch and Vaninetti, 1980; Everitt and Jones, 1980). More advanced fine coal cleaning methods involving oil agglomeration, froth floatation, and leaching in acid or caustic can be used to achieve low levels of ash if they are tailored to the feed coal. Testing is required to determine the effectiveness of different methods for a particular low-rank coal.

Washability data on U.S. low-rank coals indicate wide variability in cleanability and limited value in coarse gravity cleaning alone (Energy Resources Co., Inc., 1980; Brown et al., 1985; Cavallaro et al., 1976; Malterer et al., 1988). This is principally due to the significant fraction of the ash-forming constituents that are chemically bound as absorbed cations, which cannot be removed by physical cleaning. Ion-exchangeable cations account for over half of the ash-forming material in some low-ash U.S. low-rank coals, including most of the sodium content which adversely affects ash deposition in boilers. Also, the discrete mineral grains in U.S. low-rank coals are typically finer than those in bituminous coals and, therefore, more difficult to physically separate (Zygarlicke et al., 1990).

In the past, coal-cleaning methods have not played a significant role in sulfur control strategy for U.S. utilities because they do not have the capability of meeting the 70% to 90% removal requirement under the U.S. NSPS. The more flexible provisions in the 1990 U.S. acid rain legislation mandating retrofit of older boilers, including the provision for emission trading, should serve to increase the role of coal cleaning. In general, the effectiveness of physical cleaning to remove sulfur depends on the fraction of total sulfur occurring as pyritic sulfur, which is potentially separable. In the United States, this fraction is lower for low-rank coals than for bituminous coal, averaging 34% for North Dakota lignite (Sprouls, 1989) compared to 58% for Pennsylvania bituminous coal (Cavallaro et al., 1976).

6.2.2 Applicable Methods for Cleaning Low-Rank Coals

Gravity Cleaning Processes: Coarse gravity cleaning methods are applicable to low-rank coals within the limitations imposed by the forms of ash and sulfur present. Clean coal has a specific gravity of 1.12–1.35, compared to 2–3 for sand, shale and clay, and 4.8–5.2 for pyrites. Various equipment for gravity cleaning includes 1) jigs operating by stratification in pulsating water; 2) dense-media vessels achieving gravity separation in finely dispersed magnetite in water; 3) concentrating tables using differential movement of coal in water over an inclined, ribbed surface; 4) hydroclones achieving centrifugal separation in water; 5) dry pneumatic concentrators that substitute air for water on a dry table or jig; and 6) launders which use the differential velocity of coal and minerals down an inclined water-washed surface as influenced by specific gravity, friction, and hydrodynamic boundary layer effects.

Fine-Coal-Cleaning Methods: Finer mineral particles and pyrites are liberated as the coal is progressively ground to a smaller particle size. The principal methods used for physically cleaning fine coal include 1) dense-media cyclones which combine the effects of specific gravity and centrifugal force up to 200 g, 2) dry magnetic separation in a high-intensity magnetic field based on the paramagnetic properties of minerals that are attracted by magnetic force and the diamagnetic property of clean coal which is repulsed, 3) oil agglomeration based on the adhesive property of oil to agglomerate and separate clean coal from water, and 4) froth flotation based on the differential adhesion of water and fine air bubbles on coal and minerals. The applicability of dense-media cyclones and dry magnetic separation methods depends primarily on the properties of the minerals rather than the properties of the clean coal, and they may or may not be applicable to a particular low rank coal depending on the mineral forms present. The use of oil agglomeration for cleaning low-rank coals requires that a phenolic oil or another polar additive be included in the oil phase to allow it to adhere to the otherwise hydrophilic coal surface. Froth flotation has not been effective for low-rank coals because of the hydrophilic property of the coal surface which causes it to remain in the bulk water phase.

Chemical Cleaning Methods: Chemical cleaning methods that are potentially suitable for low-rank coals include 1) acid leaching to remove ionically absorbed cations, 2) an alternative ion-exchange treatment that substitutes calcium for sodium to alleviate boiler fouling, 3) various combinations of aqueous oxidation and chemically enhanced (e.g., caustic) leaching to remove principally pyritic sulfur, and 4) molten caustic leaching to reduce both ash and total sulfur to low levels. The cost of chemical cleaning is typically much higher than physical cleaning, with chemical methods estimated at US$12 to US$41/ton in the 1980 Low-Rank Coal Study (Energy Resources Co., 1980), which corresponds to approximately US$0.60 to US$2/GJ for a 23-GJ/kg product. The EERC has demonstrated that U.S. low-rank coals can be cleaned by a combination of wet gravity separation and acid leaching to achieve 60%–80% ash removal and 30%–80% sulfur removal, yielding a product with typically 2%–3% ash and 0.2%–0.5% sulfur (Potas et al., 1989). The combined cleaning cost was estimated at about US$0.75/GJ. Cleaning of low-rank coals to lower ash levels of 1%–2% has been demonstrated by the EERC using a combination of polar oil agglomeration and acid leaching (Potas et al., 1990).

Other principles that have been tested for coal cleaning include microwave treatment, separation in liquid CO_2, biodesulfurization, and hydrocarbonization with dolomite. These and other experimental methods may gain commercial status in the future, but for now assessment should focus on more proven physical or chemical cleaning methods.

6.2.3 Physical Cleaning of Czech Lignites

The EERC has recently completed an evaluation of cleanability for lignites from Bílina and Nástup for Ústí nad Labem in the Czech Republic (Young and Musich, 1995). Test samples were crushed and screened to separate a 0.84- to 6.35-mm size fraction for cleanability testing. The discarded finer fraction, which contained the higher concentration of ash and was not cleaned, represented 14% to 22% of the coal heating value. Wet gravity separations were performed at specific gravities of 1.3, 1.4, and 1.6. Dry separation using a rare-earth magnetic separation method (REMS) was performed on two subordinate size fractions.

Significant reductions in ash were achieved by wet gravity separation at 1.3 specific gravity for the Bílina and Nástup lignites at reasonably high energy recoveries of 89%–93%. For three samples of Bílina lignite, ash contents in the range of 5.4% to 7.2% after screening (moisture-free basis) were reduced to between 3.9% and 4.1%, representing a 23% to 43% percentage reduction. The combination of screening and cleaning reduced the ash contents of Bílina lignite samples by 38% to 51%. For the one sample of Nástup lignite tested, the ash content was reduced from 17.6% to 9.2%, representing a 48% percentage reduction for wet gravity cleaning alone and a 51% percentage reduction for screening and cleaning combined.

Substantial percentage reductions in sulfur content of 29% to 43% achieved by wet gravity cleaning on three Bílina lignite samples were in direct proportion to the percentage of the total sulfur occurring as pyrite, which also ranged from 29% to 43%. The range of total sulfur content in the Bílina samples before screening and cleaning was 1.02% to 1.23% on a moisture-free basis. Screening did not significantly lower the sulfur content. For Nástup lignite, with 34% of its 1.74% total sulfur content occurring as pyrite, essentially no sulfur reduction was achieved by wet gravity cleaning, possibly indicating that the pyrite in this sample was very finely divided and not amenable to separation.

Dry magnetic cleaning by REMS was not as effective as wet gravity separation at 1.3 specific gravity, but it did achieve significant removals of ash and sulfur for the one Bílina lignite sample tested. Combining results for two sizes tested, the REMS method achieved a 19% reduction in ash and a 29% reduction in sulfur at 95% energy recovery, compared to 43% and 39% reductions, respectively, for wet gravity cleaning at 92% recovery. For Nástup lignite, the REMS method achieved essentially no reduction in either ash or sulfur content.

The varied results of cleaning lignites from two Czech mines illustrate the difficulty of providing a general assessment on the overall cleanability of lignites and the need for testing a representative sampling of any coal being evaluated.

6.3 Evaporative Drying

A wide range of evaporative drying processes are available where coal temperatures remain below 100°C. They differ according to the design of the dryer, the size consist of the feed coal, the heat source, the quenching method, the product stabilization procedure, if any, and the utilization characteristics of the dried product. Commercially available dryers include entrained-flow (e.g., the Parry dryer), rotating drum, fluidized bed, flash mill, and steam tube designs. The application of these drying methods to upgrade coals has been constrained by problems of product stability and cost-effectiveness. Low-temperature drying unfortunately does not significantly reduce the equilibrium moisture content, causing the product to be subject to moisture reabsorption. Evaporative drying to low moisture levels also reduces particle strength, increases dust and friability, and increases the danger of spontaneous heating in handling and storage (Willson et al., 1992). However, even with these problems, the rail shipment and long-term storage of evaporatively dried U.S. lignite and subbituminous coals have been successfully demonstrated on an experimental scale (Paulson et al., 1973). The most successful example of commercial drying in the United States is the Parry dryer at the Texas Utilities generating plant in Texas, which dries lignite for direct use in slagging boilers. A fluidized-bed dryer built by the Amax Coal Company to dry U.S. Powder River Basin subbituminous coal for shipment to utilities in the U.S. midwestern and eastern regions has thus far proven unsuccessful because of fines generation and extreme dust problems.

Flash mill and steam tube dryers were developed for European and Australian brown coals for applications that include 1) the direct integration of flash mill drying with pc-firing, 2) stand-alone drying for production of briquettes, and 3) the production of pneumatically conveyed dry coal powder for use as an industrial fuel. The integrated flash mill (Kramer) design uses recirculating boiler flue gas for in-mill drying, with centrifugal separation of the dried product from the moist gas. The stability and efficiency of this process depends on careful management of the in-mill drying conditions. Steam tube drying, which was developed in Australia and licensed to Lurgi Australia, dries coal in a fluidized bed heated by immersed steam tubes, with the fluidizing agent being the moisture released from the coal. The reported capabilities of steam tube drying on brown coal include a large reduction in moisture content (from 60% to 15%) and reduced carbon dioxide emissions from the product upon heating (decreased by 17%) (Hamilton, 1990).

Experimental drying methods operating at low coal temperatures include multiple-effect fluidized beds, solar ponds, and a pulse-jet design that eliminates the need for blowers. These methods offer potential advantages where relatively large amounts of water need to be removed efficiently, but various limitations have prevented their commercial application—including the capital cost of multiple fluidized beds, the climatic dependence of solar drying, and the noise of a pulse-jet design.

The capital costs of low-temperature evaporative dryers are in the range of US$63 to US$109 per product ton year, based on a 1984 study update to current dollars (Davy McKee, 1984). The processing cost including capital charges for upgrading low-rank coal by evaporative drying is on the order of US$1/GJ of dried product, which can only be justified by offsetting savings in freight cost, boiler performance, or other utilization benefits. Freight savings alone do not come close to covering this level of processing cost, and credits must be identified in areas of coal handling, pulverizers, boiler capacity and availability, and emissions control performance. In the United States, these offsetting savings are being investigated where there are opportunities for substituting low-sulfur subbituminous coal for high-sulfur bituminous coal without incurring extensive charges for boiler modifications

6.4 Intermediate Temperature Drying

Drying processes that raise the temperature of the coal above 240°C permanently change the physical and chemical properties of low-rank coals and yield a product with a lower equilibrium moisture content. At these temperatures, tar migrates to the coal surface where it seals surface pores and significantly reduces the ability of the coal to reabsorb moisture. Evolution of CO_2 also reduces the capacity of the coal to chemically bind water by removing hydrophilic carboxyl groups.

Different intermediate temperature drying processes have been developed using hot gas, steam, hot water, or oil. The quality of the dried product depends more on temperature than on the drying medium. Updated capital costs for intermediate temperature dryers are in the range of US$101 to US$146 per product ton year, or about 30% to 50% higher than for low-temperature evaporative dryers (Davy McKee, 1984). Processing costs including capital charges, based on the same source, are in the range of US$1.36 to US$1.55/GJ, or about 10% to 30% higher than for low-temperature drying. Process improvements in solids separation and handling or heat recovery have been reported to reduce both capital and operating costs.

6.4.1 The Syncoal Drying Process

The Syncoal process drys low-rank coal in hot combustion gas to produce an upgraded boiler fuel. The technology has been demonstrated under the U.S. Clean Coal Technology program, operating on Montana subbituminous coal and North Dakota lignite (Sheldon and Heintz, 1995; Niquette, 1994). The process incorporates staged drying in two vibratory fluidized beds followed by a water quench, cooling in another vibratory fluidized bed, and pneumatic separation of ash, including up to 90% of the pyritic sulfur. When applied to lignite feed, the process has achieved a 31% reduction in ash (db), a 53% reduction in specific sulfur emission (g of SO_2/GJ), and a 53% increase in fuel heating value (16.4 to 25.1 GJ/kg). Boiler tests on the dried coal product have shown improvements in boiler cleanliness, efficiency, and generating capacity, with no adverse effect on NO_x emissions. A commercial plant has been proposed to produce 500,000 tons per year of product from North Dakota lignite at a plant construction cost of US$43 million. The economic justification for this project in boiler fuel markets depends on the U.S. alternative fuel tax credit and the offsetting cost savings expected in transportation, boiler performance, and SO_2 emission reduction.

6.4.2 Hydrothermal Drying Processes

A number of intermediate temperature drying processes for upgrading lignite as a solid fuel have been designed to operate by heating coal under saturated steam/water to temperatures between 240°C and 380°C, including development efforts performed by the EERC, K-Fuel, Bechtel, IGT, Shell and others—all somewhat related to the older batch Fleissner process. The semicontinuous K-Fuel Series C process has been demonstrated on a 450-kg-per-batch scale in Gillette, Wyoming, in the United States. When operating on subbituminous coal, the process has achieved up to 25% sulfur removal and an increase in heating value from 18–19 GJ/kg to above 28 GJ/kg (Merriam and Gentile, 1995). The advantage of using moderately higher temperatures, as discussed above, is that the structure of the product is altered by decarboxylation and migration of tars to the coal surface such that moisture reabsorption is reduced and product strength and stability are improved.

6.4.3 Hot Oil Drying

The Carbotech hot-oil drying process was initially selected in Round IV of the U.S. Clean Coal Technology Demonstration Program, but the demonstration was not implemented because of technical and financial questions. The concept of drying in hot oil was developed as early as 1926 and was later used by Exxon in their donor-solvent direct liquefaction process (Willson et al., 1992). The Carbotech technology uses two stages: first to dry the coal in hot oil and then to recover oil by flue gas stripping. A small amount of oil remains absorbed on the coal, which reportedly serves to stabilize the product. Some difficulty has been experienced in achieving the high level of oil recovery needed to make hot-oil drying economically feasible.

6.5 Upgrading Processes Based on Pyrolysis

6.5.1 The LFC/Encoal Process

The "liquids from coal (LFC) pyrolysis process" is being demonstrated under the U.S. Clean Coal Technology Demonstration Program (Castro et al., 1994; McCord et al., 1993) to optimize techniques for producing both premium solid fuel and liquid fuels from low-rank coals. Coal is processed in three stages, including controlled drying, pyrolysis, and cooling in inert gas with rehydration and dust suppression. Liquids are collected in quench columns and an electrostatic precipitator, and the low-calorific value gas produced is burned to supply process heat. The economics of the process have been evaluated for Polish lignite containing 58.7% moisture (Castro et al., 1994) based on utility-type financing at a 10% cost for capital, with the following findings being reported: 1) a capital cost of US$560 million for a char plant producing 4 million tonnes/yr (heating value 28 GJ/kg), sufficient to supply fuel for four 360-MWe generating units; 2) a levelized processing cost including capital recovery of US$0.95 per GJ of product (char and oil), excluding the cost of the coal feedstock; and 3) energy recovery of 77% in char and 8% in oil in relation of lignite feed. In special circumstances where a one-third reduction in sulfur emission (kg SO_2/GJ), as offered by the LFC process, meets the required emission standard, the LFC process is estimated to offer a significant cost advantage over FGD (cost ratio 1/1.5) after credits are taken for the sale of oil at US$15/bbl and for a 9% improvement in electrical generating efficiency (Castro et al., 1994).

6.5.2 The FMC Process and Other Form Coke Technologies

The FMC Corporation in the United States operates a commercial pyrolysis plant at Kemmerer, Wyoming, producing briquetted formcoke® from low-sulfur subbituminous coal for use in reducing phosphorus ore. The FMC process can be configured in different ways by appropriately selecting a series of fluidized-bed reactors to accomplish drying, preoxidation to reduce caking, carbonization, and/or calcination as required. The process can be applied to coals of different rank, including caking bituminous coals. At Kemmerer, the hot char is combined with polymerized tar and supplemental binder to form briquettes which are cured, calcined, and finally cooled to give a high-strength low-volatile formcoke®. A 20,000-ton test at Inlant Steel demonstrated that the FMC formcoke® can be successfully used in a blast furnace.

Many other form coke processes have been investigated over the last 40 years using both high- and low-rank coals. The principal goal has been to develop a technically, environmentally, and economically satisfactory substitute for slot-oven coke for use in blast furnaces and, to a lesser extent, in iron foundry cupolas. Driving forces behind this development effort have been 1) decreasing supplies of good quality coking coal, 2) increasing prices for good quality coke, and 3) the need for a fully contained process that can control the pollution arising from traditional slot ovens. Despite extensive interest, only two commercial form coke plants are known to be operating: the Sastech plant in South Africa and the FMC plant in the United States. In addition, the Samchully plant in South Korea produces cylindrical briquettes from a mixture of petroleum coke, coke breeze, anthracite, and coking coal.

Recent developments in form coke technology have been undertaken in the United States, Canada, and Germany, most notably within the U.S. DOE mild gasification program discussed below. The U.S. Salem Company has successfully tested a rotary pancake furnace in the United States and Germany for the production of semicoke and for smokeless fuel production in Canada. This process has been considered for the production of semicoke from Czech coals (Buchtele and Straka, 1994).

6.5.3 The U.S. DOE Mild Gasification Program

Starting in the mid-1980s, the U.S. DOE sponsored research on four carbonization (mild gasification) processes at the scale of 100 lb (45.5 kg/hr) of coal feed per hour for the purpose of optimizing char properties and liquid yields and qualities from a variety of U.S. coals under low-severity conditions that could potentially be economic in existing markets. The most significant differences among the processes were in the reactors and the gasifying atmospheres, with all operating at near-atmospheric pressure. The EERC investigated a two-stage spouting fluidized-bed reactor using hot combustion gas and steam as the gasifying atmosphere; the process was operated on a mildly caking high-sulfur Indiana (U.S.) bituminous coal under conditions that optimized sulfur removal from the char and separation of liquid condensates (Sondreal et al., 1989; Aulich et al., 1991). The Coal Technology Corporation developed a twin-screw reactor for using highly caking eastern U.S. bituminous coals; a continuous process for producing form coke was demonstrated at a pilot scale of 10 tons per day and patented (Wolfe et al., 1989, 1995). The Western Research Institute performed studies in an inclined fluidized-bed reactor operating on indirectly heated recycle gases; products from a western U.S. subbituminous coal were a char that was converted to carbon black and a relatively high heating value gas. Finally, IGT used an externally heated, spouted fluidized bed optimized to operate on caking coals using preheated inert gas (Babu et al., 1989). The IGT process is being scaled up under U.S. DOE sponsorship for production of form coke.

The market assessments performed in conjunction with the EERC mild gasification project (Sinor, 1992, 1988) indicate that there are many technically feasible opportunities for producing upgraded coal products, including metallurgical coke substitutes, activated carbons, sorbent chars for control of toxic emissions, and liquid fuels and chemicals. Some of these markets are reviewed in section 7.0. The general conclusion is that the high cost of producing marketable products and the challenge of meeting traditional market specifications will constrain commercial development. For example, the financial analysis for a form coke plant sized to produce 129,000 short tons per year from a bituminous coal priced at US$20 per ton indicated a discounted cash flow (DCF) rate of return of only 8.1% at a form coke selling price of US$150 per ton, which is higher than prevailing prices for conventional slot-oven coke (Sinor, 1982). The best prospects for profitability would appear to be in making low-volume products having a very high added value, such as activated carbons, where market success depends primarily on the performance of the product.

6.6 Low-Rank Coal-Water Fuel (LRCWF)

6.6.1 Process Description

The technology for producing LRCWF from brown, lignitic, and subbituminous coals was pioneered by the EERC in a 6-tpd pilot plant by hydrothermally treating normal pc-grind coal in saturated hot water at about 285°C and a pressure of 1100 psi (75 bar). A commercial-scale demonstration project based on the EERC's LRCWF technology is being planned for Alaska in the United States. Also, a consortium in Japan and the State Electricity Commission of Victoria in Australia have recently constructed LRCWF pilot plants modeled after the EERC design, and interest has been expressed for a dredge-mined Kovin lignite in northern Serbia (Ljubičić et al., 1994; Yui, 1995). Under the conditions of this process, water is irreversibly expelled from the coal; carbon dioxide is released; and devolatilized tar is deposited on the surface of coal particles to prevent water reabsorption. After hydrothermal processing, excess water is removed to produce a stable pumpable slurry with a dry solids content of about 60%. Sufficient oxygen content is retained in the coal to maintain its hydrophilic character, so that the LRCWF has little tendency to settle and exhibits good viscosity characteristics without additives.

6.6.2 Economics of LRCWF

The projected selling prices for LRCWF cover a range from about US$1.60 to US$3.70/GJ depending on a number of variables: 1) coal cost, 2) product specifications (e.g., level of coal cleaning), 3) plant size, and 4) varying capital costs. This overall range is competitive with refined petroleum in the Rotterdam market, based on April 1995 prices for

1% sulfur residual oil at US$17/bbl (US$2.54/GJ) and No. 2 fuel oil at US$21.60/bbl (US$3.43/GJ) (Oil and Gas Journal, 1994). LRCWF is generally not competitive with steam coal in international trade, for which the International Steam Coal Market ranged from US$34 to US$42/ton (US$1.24/GJ to US$1.51/GJ) during 1994 (International Coal Report, 1994). The capital cost of a plant for producing 4 million short tons per year (tpy) of LRCWF is estimated to be on the order of US$300 million, generating a capital cost of about US$0.70/GJ. A breakdown of the nominal US$2/GJ production cost for a 4-million-tpy plant includes US$0.66/GJ for coal, US$0.13/GJ operating labor, US$0.27/GJ utilities, US$0.24/GJ general maintenance, and US$0.70 in debt payment for 12% financing over a term of 20 years (Anderson, 1995). Adjusting for plant size based on a 0.6 exponential factor, the corresponding costs at 1.5- and 10-million-tpy capacities would be approximately US$1.60 and US$2.70, respectively. At 4-million-tpy capacity, the incorporation of physical coal cleaning would add nominally US$0.30/GJ, and chemical cleaning by acid leaching would add an additional US$0.70/GJ. The added cost of chemical cleaning would be considered only for direct firing of LRCWF in diesel or gas turbine engines, which is being studied under the U.S. DOE Research & Development program. Lower processing cost estimates down to US$0.73/GJ, exclusive of coal feed cost, have been advanced for a small modular plant design for producing 500,000 tpy (International Coal Preparation Consultants Limited, 1995). Lower costs could also be achieved by integrating the LRCWF process into an advanced IGCC power system that uses a coal slurry feed, such as the Texaco and Destec gasifiers. Where slurry feed equipment is already included in an IGCC power system, the incremental cost of adding hydrothermal treatment and slurry concentration is estimated to be on the order of US$0.30/MJ (Anderson, 1995). Current uncertainty in process cost estimates will be narrowed by the demonstration project being planned for Alaska in the 1995–1999 time period.

6.6.3 Pipeline Transportation

Pipeline transport is economically justified at product volumes above 5 million short tons per year. The low settling rate of LRCWF allows pipelines to be designed for laminar flow and provides flexibility for interrupted flow, which would not be possible for a coarse coal–water slurry pipeline. For long-distance shipment, costs are estimated to be US$0.025/ton mile plus US$2.50/ton for terminal transfer charges (International Coal Preparation Consultants Limited, 1995). For a LRCWF heating value of 15.8 MJ/Kg, the resulting 500-mile shipping cost of US$15/ton is equivalent to US$1.05/GJ. This estimate is in general agreement with U.S. pipeline transportation costs for petroleum on a tonnage basis, which averaged US$0.017/short ton-mile in 1994 (Oil and Gas Journal, 1994). However the unit cost of a short pipeline could be considerably higher, based on an estimate of US$0.06/ton mile for a 21-mile (34-km) pipeline of nominal 20-inch (51-cm) diameter studied for transporting 5 million tpy of LRCWF in Alaska (Willson et al., 1991). The design and cost studies were based on calculations of pressure drop for a pseudoplastic fluid in laminar flow, which predicted a pressure prop of 1.75 bar/km at a slurry velocity of 0.72 m/sec; capital cost was estimated at US$25 million, annual operating cost at US$2.8 million, and annualized capital cost at US$4.3 million.

7.0 ALTERNATIVE MARKETS FOR LIGNITE

Traditional markets for lignite in the Czech Republic are expected to decline in the coming decade with the decommissioning of older coal-fired power plants after completion of new nuclear units and the conversion of district heating plants and other use sectors to natural gas. Alternative uses for extensive reserves of lignite, which make up the largest economically viable energy resource in the Czech Republic, represent an important goal for the Czech national economy and for the welfare of displaced miners.

The search for new uses for lignite under current market realities in the Czech Republic and elsewhere should take into account previous successes and failures in the field. The availability of natural gas and crude oil in world markets at prices in the range of US$1.50 to US$3.00/GJ at the wellhead places a strict upper limit on the value of coal-derived fuels. Any successful upgrading process must provide a substantial added value to pay for the cost of processing and a profit. This tends to focus attention on limited-tonnage high-value fuel products such as smokeless briquettes for space heating and on non-fuel products such as activated carbon rather than on upgraded boiler fuels.

7.1 The Experience of North Dakota Lignite in the United States

A challenge similar to that experienced in the Czech Republic is faced by the North Dakota lignite industry in the United States, where production reached a plateau in 1985 and is currently poised between future expansion into new markets or possible decline due to environmental and price competition from other fuels. The past history of the North Dakota lignite industry also parallels current trends in the Czech Republic, with the closing of 320 small underground mines in North Dakota during the 1940s and 1950s and progressive consolidation of production into five large surface mines that efficiently produce 30 million tons annually at a productivity of 129 tons per miner per 8-hour shift. Major expansion in lignite production occurred between 1965 and 1985 with the building of eight large regional electric generating plants and the Great Plains Gasification Plant producing synthetic natural gas (SNG). However, growth has peaked, and future expansion is constrained by electric transmission line capacity and the availability of premium low-sulfur subbituminous coals in the bordering states of Montana and Wyoming at mine-mouth prices as low as US$0.25/GJ.

To meet this competitive challenge, the state of North Dakota in 1987 formed a strategic partnership with the lignite industry to perform research and development for the purpose of expanding lignite production and employment through market diversification. One of the activities under that program has been a marketing feasibility study performed to identify ways for improving the competitive position of lignite through other resources as a fuel or raw material (Sinor, 1992). Selected findings of this report and other upgrading studies which have potential application to Czech lignite are summarized in the sections below.

7.2 Upgraded Utility Boiler Fuels

Thermal processes for drying or carbonizing lignite to produce upgraded solid boiler fuels typical involve capital costs in the range of US$68 to US$157 per product ton of annual capacity and processing costs including capital recovery on the order of US$1 to US$1.50 /GJ (Davy McKee, 1984; Sinor, 1992 [costs updated to 1995]). These levels would effectively double the unit energy cost of a Czech lignite feedstock, making the upgrading methods at best only marginally competitive for large-scale electric power generation. In the United States, a niche utility market for coal upgrading is being explored under the Clean Coal Technology demonstration program for applications involving fuel switching from high-sulfur bituminous coal to low-sulfur compliance fuels, which are being prepared by cleaning and drying or carbonizing subbituminous coals or lignites (U.S. DOE, 1994).

At current oil price levels, the cost of coal carbonization processes cannot be supported by selling coal liquids, and financial success depends on receiving a premium price for the char or dry-coal product. Economic benefits that can be used to justify a price premium for char fuels in utility boilers include reduced costs for transportation, handling, and storage; pulverizers; boilers; and emissions controls. Also, boiler tests on upgraded coal products have shown operating improvements in boiler cleanliness, efficiency, and generating capacity, with no adverse effect on NO_x emissions. Currently in the United States, the economic feasibility of upgrading coal depends on the availability of an alternative fuels tax credit which may offset up to about US$1/GJ in processing cost.

In the past, a number of commercial coal pyrolysis plants for producing char and liquid fuels were built in the United States starting in the 1920s, but none remains in operation. Texas Utilities built a power plant in the 1950s to burn char from a pyrolysis plant, but the production of liquid fuel was not economically successful, and the power plant was modified to burn dried lignite (Sinor, 1988). The Amax Coal Company constructed a commercial fluidized-bed dryer for U.S. subbituminous coal in 1988 which failed because of its extremely fine and dusty product (Woessner, 1993). The Syncoal and Encoal upgrading projects currently under way as part of the U.S. Clean Coal Technology program are addressing problems of product quality.

In summary, the primary barrier issue to be addressed in upgrading lignite to a premium solid boiler fuel is cost, followed by the need to be sure that the product has sufficient strength and stability to prevent unacceptable moisture reabsorption, decrepitation, dust, and spontaneous heating during transportation, handling, and storage (Willson et al., 1992).

7.3 Smokeless Briquettes

The production of smokeless fuels from brown coals and lignites was the topic of a workshop sponsored by the U.S. Department of Energy in Prague in November 1994 (Energy & Environmental Research Center, 1995). The term smokeless is defined by a reduction in the tarry volatiles released during coal combustion. Both briquetted fuels and lump coal are used extensively throughout East Central Europe for residential space heating, as well as commercial and small industrial heat generation. Most of these applications do not involve high-quality low-sulfur fuels, and conversion to a smokeless solid fuel at significant added cost will likely be accomplished only through emissions legislation. Standards are set either by the emission rate (e.g., 5 grams per hour in the United Kingdom) or by the volatile content of the fuel (a maximum of 15 wt% defines smokeless fuel in the Czech Republic). Technically feasible improvements in production methods that would substantially resolve dispersed air pollution problems from the household use of coal or briquettes are available based on a variety of advanced methods for coal cleaning, drying, carbonizing and briquetting with additives.

The potential size of the market for smokeless fuels is illustrated by the estimated 50 million tons of residential solid fuel used throughout East Central Europe, including the Ukraine (Crowther, 1994). Briquettes of varying quality account for only about one-fourth of this total, and briquette production has been declining for economic and ecological reasons. Poland has closed its conventional (noncarbonized) briquetting plants and is now producing 180,000 tons of smokeless fuel per annum. Production of conventional briquettes in the former East Germany has declined by 90% to under 6 million tons per year for economic and ecological reasons. In western Germany, the current production of 10 million tons of brown coal briquettes represents only 15% of capacity. In the Czech Republic, only one plant, producing 600,000 tons per year of partially devolatilized briquettes, remains in operation at Vřesová, after the plant at Tisová was closed in 1993.

The consensus of the 1994 workshop in Prague was that a significant market for smokeless fuels in East Central Europe can be served by small plants using indigenous coals and drawing on some of the developmental methods described in Section 3.0 of this report. Imported natural gas and anthracite are the competing alternatives. Several smokeless fuel projects are being implemented or planned, including the ECOCOAL process in Poland (Dreszer and Ściażko, 1994), MIBRAG in central Germany (Mall, 1994), and an Ostrava hard coal project in the Czech Republic (Kren Consulting, 1993). Specifications for future smokeless fuels will typically include a volatile content below 10%; sulfur content below 1%; high heat content (e.g., 25 MJ/kg); good strength—both wet and dry; good ignition characteristics; low ash, size, and shape appropriate for heating appliances; and reasonable cost. Representative costs given for smokeless briquettes are in the range of US$80 to US$120/metric ton, or US$3.20 to US$4.80/GJ at a heating value of 25 MJ/kg.

7.4 Dry Lignite Powder

Dried lignite or brown coal powder is generally used on-site in combustion boilers following drying to reduce excessively high moisture (e.g., up to 70 wt% moisture in brown coals). The coal can be dried directly as in the Kramer mills used for Victorian (Australia) brown coal (Garner, 1984) or in an entrained-flow reactor (e.g.,Parry dryer) as with Texas lignite (Texas Utilities, 1977). An indirect drying method being used in Australia for Loy Yang (Victoria) brown coal incorporates a steam heat exchanger immersed in a fluid-bed system (Hamilton, 1990).

Drying lignite for off-site use was pioneered in Germany, where it has been practiced for over 15 years. Currently, some 2 million metric tons/year of lignite powder are produced by grinding the dried material from a tubular steam drier and mixing it with the fines collected from ESPs. The dried powder is transferred pneumatically by air and stored in silos, carefully designed and with the necessary safety controls. The powdered product is delivered by road or rail tanker and handled pneumatically for use in the cement industry (Couch, 1990).

Germany is also producing pulverized and granular coke from Rhenish lignite for a variety of uses, including waste gas and wastewater cleanup, steel manufacture, electric furnace metal smelting, graphitization, and activated carbon manufacture. The noncaking Rhenish lignite containing alkaline constituents is produced in the following three sizes: <0.4, 0–1.5, and 1.25–5 mm. Grain sizes are selected to match the application (Schieb, 1994).

In the Czech Republic, fine dried lignite products having a calorific value between 21 and 25 MJ/kg and a low sulfur content of 0.5%–0.8% are obtained from the gasification and briquetting plants operated by the Sokolov Coal Company at Vřesová (Keller et al., 1994). Lignite dust is separated from the dried feed stream going to Lurgi fixed-bed gasifiers, taken from ESPs downstream of a steam tube dryer. Lignite powder is also produced by grinding dried coal from the briquetting plant. The dried products are pneumatically conveyed in nitrogen to special storage tanks and trucks to be supplied to consumers.

7.5 Marketing Opportunities for Low-Rank Coal–Water Fuel

CWF is a mixture of finely ground coal, water, and a chemical stabilizing agent that is designed to replace heavy fuel oil in industrial and utility boilers. The product is handled like oil, using similar tank storage, pumps, and atomizing equipment. With deep cleaning to reduce ash and sulfur, future markets for CWF may include marine and railroad diesel engines and gas turbines. CWF can be produced from either bituminous coal or low-rank coals (subbituminous, lignitic, or brown coal), but the processes involved are substantially different.

Until recently, development of CWF has been primarily based on bituminous coal, which, because of its low moisture-holding ability, can be used directly to produce CWF without prior thermal treatment to remove inherent moisture. However, since bituminous coal is hydrophobic (the surface repels water), additives are needed to reduce the viscosity of the CWF and to prevent settling. The added cost of additives has been a major deterrent to commercial development of CWF in the United States. However, in some regions of the world where coal pipelines are more economic than new rail transport facilities or fuel diversity is desired to avoid dependence on imported oil, commercial development of CWF is already well advanced. Production of 4.3 million tpy of bituminous CWF commenced in Russia in 1989 to supply fuel for six 220-MW utility boilers through a 163-mile pipeline from Belevo to the Novosibirsk power plant. An Italian firm, Snamprogetti, is involved in the Russian project and also recently opened a 500,000-tpy CWF plant in Sardinia this year. In Japan, where fuel diversification is a strategic policy issue, over 1 million tpy of CWF capacity has been constructed to utilize imported bituminous coal, and an additional 1-million-tpy capacity has been built in Yanzhou, China, to supply bituminous CWF. Japan is expected to utilize up to 8 million tpy of CWF by the year 2000.

A potentially large market for CWF exists around the world because of the many oil-fired utility boilers that are not fully utilized. For example, only about 40% of the oil-fired capacity in western Europe is currently used (Sinor, 1992). Bituminous CWF, at an estimated cost of about US$3/GJ, can be economically competitive with fuel oil in some oil-fired utility applications, but it cannot compete with coal in boilers designed to burn coal directly. Industrial boilers represent a future market with different retrofit requirements.

The combustion characteristics of CWF are linked to coal characteristics and hardware design, including the atomizer, burner, and configuration, as first summarized by Beér (1985) and more recently by Anderson et al. (1994). Combustion programs at ABB Combustion Engineering in the United States have developed retrofit burners for a range of CWF applications involving different bituminous coals and ash levels (Sinor, 1992). Initially, bituminous CWF experienced poor combustion performance because of particle aggomeration during heating through the plastic state, but this has been partly remedied by improving atomizer design to achieve acceptable carbon burnout in boilers having a residence time of several seconds. In compactly designed oil-fired boilers and coal-fired diesels or gas turbines, where burnout must occur in a fraction of a second, carbon burnout can only be achieved for bituminous CWF by fine grinding, at significant added cost. Since ultrafine grinding can also result in undesirable (dilatent, shear thickening) flow behavior and poor atomization, a compromise must be reached between the fineness of grinding and the rheological characteristics of bituminous CWF.

Low-rank coal–water fuels (LRCWF) offer important advantages in achieving rapid carbon burnout without fine grinding because of the high reactivity of the feed coal and the retention of volatile tar on particle surfaces during processing. Combustion tests on normal pc-grind subbituminous LRCWF produced by the EERC have demonstrated superior carbon burnout in both conventional residence time firing (e.g., 99.8% burnout) and short residence time firing in a gas turbine (>99% compared to 97% for micronized bituminous CWF) (Anderson et al., 1994). Sulfur emissions can be reduced by precleaning the feed coal. Also, the addition of small amounts of limestone to LRCWF has been shown to be effective in reducing sulfur emissions in preliminary tests at the EERC. Processing in hot water also serves to remove soluble alkalies which are a principal cause of severe boiler fouling when burning high-sodium coals. LRCWFs from various test coals have typically produced a fine, powdery fly ash which is less likely to cause erosion and deposition problems in compact boilers than bituminous coal ash.

The cost of processing LRCWF is estimated to be in the range of US$1 to US$3/GJ without the cost of the feed coal, depending on the product specifications (e.g., ash and sulfur contents); the moisture, ash, and sulfur contents of the feed coal; the size of the plant and economy of scale; and variations in the cost of capital. LRCWF is competitive with both fuel oil and bituminous CWF and may offer economic advantages in retrofit cost and emissions compliance depending on the feed coal properties and precleaning. The high reactivity and favorable ash characteristics of LRCWF are expected to allow for less boiler derating and auxiliary fuel use compared to bituminous CWF.

In the Czech Republic, interest in the production of LRCWF would likely be restricted to industrial boilers currently burning fuel oil and not involve utility boilers. Lignite feedstocks for producing LRCWF for oil-fired industrial boilers should contain minimum amounts of sulfur and ash. Cleaning by wet gravity or dry magnetic methods should also be considered to improve the quality of the product. Based on the data for Czech lignites given previously in Table 1, the selected samples of Bílina lignite analyzed by the EERC show an average ash content of 7.3% (db) and sulfur content of 1.2% (daf). Wet gravity cleaning of these samples at 1.3 specific gravity yielded 4.0% ash and 0.7% sulfur contents at 90%–93% energy recovery, and dry magnetic cleaning resulted in 5.6% ash and 0.8% sulfur at 95% energy yield. These analyses indicate that selected sources of Bílina lignite would be suitable feedstocks for producing LRCWF and that precleaning would offer significant benefits in improving product quality.

7.6 Form Coke

Trends in the metallurgical industry are generating a growing interest in alternative sources of coke because of heightened environmental regulation, scheduled shutdowns of aging slot ovens, increased prices for high-quality coke, and specialized needs of foundry iron and steel producers. Manufacturers of coke are demanding new processes that are environmentally acceptable and that offer increased efficiency and high quality at market-competitive prices. The growing impact of environmental legislation around the world is forcing coke producers to expand their interest to include low-sulfur low-ash noncaking coals. The form coke process is adaptable to the nature of the coal since the processing conditions can incorporate appropriate steps for either caking or noncaking coals. Further, the form coke process is continuous, in contrast to the slot-oven coking process.

Formed coke can be produced in different sizes, shapes, and qualities to meet the needs of selected markets. Metallurgical processes depending on high-quality carbon, such as that derived from wood, are increasingly being forced to use higher-cost products as supplies of timber decrease, labor costs increase, and environmental regulations become more stringent and widespread. Char made from low-ash low-sulfur coal offers an acceptable high-quality alternative. The Japanese steel industry, in particular, sees the need for a range of form coke products for iron, steel, and metal smelting operations. For example, Nippon Steel has developed dumbbell-shaped briquettes that improve gas permeability in its blast furnaces. By modifying the furance heating cycle, Nippon Steel has also been able to control the problem of fissure generation in the utilization of form coke (Kato and Komaki, 1994).

7.7 Synthetic Liquid Fuels

Synthetic liquid fuels produced by the direct hydrogenation of coal are estimated to cost approximately US$30/bbl using the most recently developed liquefaction technologies. These fuels cannot compete with refined petroleum products at current world crude oil prices of about US$20/bbl. However, starting in the 1930s and 1940s, substantial quantities of liquid fuels from coal, totaling more than 1 million tons annually, were produced in a number of European countries, including a plant in the Most region of the Czech Republic built in 1942 for the hydrogenation of lignite tar. The Most plant and other coal liquid plants that continued to operate into the 1960s, including plants at Leuna, Bohlen, and Zeitz in central Germany using brown coal, have all since been decommissioned for economic reasons. The only plants currently producing substantial amounts of motor fuels from coal are the three Sasol synthesis gas plants in South Africa with an estimated total production of 150,000 bbl/day (about 6 million tons per year) of gasoline, diesel fuel, waxes, and specialty products. The special conditions that justified European plants to be built starting in the 1930s and in South Africa in the 1950s and 1980s do not exist in Europe or the United States today. Changing circumstances that would favor a renewal of interest in synthetic coal liquids would be either a substantial rise in world oil prices, which is likely in the long run but unpredictable in the short term, or else a breakthrough in the technology for producing liquid fuel from coal. There is some scientific basis for expecting a significant reduction in the cost of liquid fuels produced from lignite based on highly favorable yields from staged low-severity laboratory studies (Hetland et al., 1995).

7.8 Methanol

Methanol is being produced from coal in the United States at the Tennessee Eastman plant in Kingsport, Tennessee. In general, methanol made from coal is not currently competitive with production from natural gas because of the much higher capital cost of a coal-based plant. However, demand for methanol is rising because of its use along with isobutylene for producing methyl *tertiary*-butyl ether (MTBE). MTBE and other oxygenates are being added to gasoline in the United States to promote combustion efficiency to meet the requirements of the 1990 U.S. Clean Air Act Amendments. Market analysts predict that a substantial amount of new methanol production capacity will be needed for several years (Sinor, 1992), and in special circumstances, some of that capacity may be coal based. In particular, coproduction with electric power generation has been evaluated as a promising approach, where the methanol would be produced in a once-through process and the unconverted synthesis gas would be used as fuel for an IGCC plant. The one-step liquid-phase process developed by Chem Systems and Air Products in the United States offers the additional benefit of using carbon monoxide-rich synthesis gas directly without water/gas shift conversion from CO to hydrogen and subsequent removal of carbon dioxide.

7.9 Synthetic Natural Gas

Synthetic natural gas (SNG) is being produced in the United States from North Dakota lignite at the Great Plains plant, which was commissioned in 1984. This plant uses fourteen Lurgi Mark IV gasifiers to convert 6 million tons of screened lignite (6- to 50-mm size) to synthesis gas that is cleaned and converted to 50 billion standard cubic feet of methane or SNG annually (1.6 billion standard cubic meters), equivalent to about one-fourth of natural gas demand in the Czech Republic. The project was conceived in the 1970s when it was believed that the United States would run short of natural gas supplies and that prices would rise above the US$6/GJ level necessary to support the cost of producing coal-derived methane. That expectation was not realized, with the wellhead price of natural gas instead dropping to current low levels of under US$1.50/GJ in the United States. As a consequence, the US$2 billion captial investment in the plant could not be repaid, and the private consortium of five regulated gas pipeline companies that built the plant defaulted on the federal loan guarantee in 1985, causing ownership of the plant to pass first to the U.S. DOE and then to the Dakota Gasification Company at a substantially reduced investment cost. However, even the operating cost for producing SNG is approximately US$2.50/GJ, and the plant is operating under sales agreements with four of the sponsoring gas pipeline companies that continue to provide demand payments compensating for the low market price of the gas until the year 2001. The Dakota Gasification Company has devoted considerable effort to increasing revenues through by-product sales, which accounted for about 12% of plant income in 1993. By-products include phenol, cresylic acids, naphtha, creosote, krypton and zenon gases, nitrogen, ammonia, and sulfur. Plans are under way to change the plant's sulfur control technology to a first-of-a-kind ammonia based scrubbing process that will produce ammonium sulfate fertilizer instead of elemental sulfur. Also, future plans call for converting one-fourth of the plant's capacity to ammonia production, which recently reached historic high price levels in U.S. fertilizer markets. In summary, the Great Plains plant is expected to continue to operate profitably by shifting its product distribution away from low-priced SNG to higher-value fertilizer and fuel products. Commercial success rests on the favorably low purchase price for the plant when it was acquired by Dakota Gasification Company in 1988, and new ventures for producing a similar mix of products from coal would be doubtful in the near future.

7.10 Activated Carbon

Activated carbons of various qualities are widely used both in liquid-phase applications for separation of organic or inorganic compounds and in gas-phase applications for solvent recovery and air toxics control. At present, the purification of drinking water and treatment of wastewater are the largest uses of activated carbon in the United States. However, as air pollution standards become stricter and more widely applied, the use of activated carbons to control gaseous effluents from numerous sources such as metallurgical and chemical plants, wood product facilities, waste incinerators, and even paint shops and dry cleaning establishments will increase substantially. Activated carbons can be tailored to achieve some degree of selectivity in separating acid gases, halogen compounds, heavy metals, mercury vapor, volatile organic carbons, and other pollutants from liquid and gaseous effluent streams. The average value of activated carbons in the United States was approximately US$1000/ton for powdered activated carbon and US$2000/ton for granular activated carbon in 1990 (Sinor, 1992), providing a potential opportunity for producing a high value-added product for a growing market.

Lignite from the U.S. Gulf Coast region is presently used to produce activated carbons, but overall, a wide range of raw materials are used, including higher-rank coals and other materials such as coconut shell, wood, petroleum coke, peat, and bone. The starting material importantly affects the surface area and pore size distribution of the product, and it is these properties that determine the suitable applications for various activated carbons produced from different raw materials. Currently, brown coal- and bituminous coal-based carbons are being used for adsorbing SO_2, HCl, mercury vapor, and volatile organic carbons from waste incinerator stack gases in Germany and Japan. With the addition of ammonia to the flue gas stream, NO_x can also be controlled. As environmental regulations become more stringent in the United States, these capabilities may be applied to power plants, cement kilns, and other combustion sources, as well as waste incinerators. The EERC is performing research to modify the surface of U.S. lignite char to provide optimum capture of mercury vapor in both metallic and chloride forms.

7.11 Humate Soil Conditioners and Ion-Exchange Products

Several upgraded products in research and production stages are based on the exchange properties of humic acids in agricultural uses, wastewater treatment, and other applications. The cation exchange, pH buffering, and water retention properties of coal humates are similar to those of organic matter in soil and peat. Various formulations prepared from coal have been used to improve the physical, chemical, and biological fertility of deficient soils. The use of brown coal directly to increase the tilth and friability of clayey soils has been demonstrated, but it is not practiced commercially. Research worldwide to produce long-lasting fertilizers based on coal humates have met with varied success (Heng, 1991). High-temperature treatment of coal humate in air and ammonia at 300° to 350°C have had limited success because of tar toxicity and poor nitrogen availability. However, near-ambient sequential processing in dilute nitric acid, ammonia, concentrated nitric acid (for oxidation), and ammonia for final neutralization has been used to produce ammoniated polycarboxylic acid (AMP) fertilizers that are as effective as urea. A related process in Japan is used to produce Azumin, a nitrogen fertilizer for gardening. Other researched applications for coal humates include the treatment of contaminated soils, reclamation of mined land, control of odor, and the coating of seeds to improve germination.

Purified humic acids are also used in various applications such as oil well drilling mud formulations, binders, and wastewater treatment. Extraction of humic acids from oxidized coal at yields as high as 80%–90% can be accomplished by treating with alkali (NaOH, KOH, or NH_4OH) and reacidifying to precipitate the solubilized humic material. The useful properties of the purified humic acids include high cation exchange capacity, anion complex formation, pH buffering, transfer of nutrients in plant physiology, and the formation of viscosity-controlling gels. The action of humic acid as a biostimulant is not firmly established.

The Research Institute of Inorganic Chemistry in Ústí nad Labem has reported promising results from work on humic acids supported by Bílina Coal Mines (Kozler et al., 1993). Selected coals containing 13%–15% mineral matter and 75 wt% humic acids have been shown to have good ion-exchange potential for separating heavy metal (Cd, Pb, Ra) from industrial wastewater. Humic acids have also been used in fertilizer formulations. Results are covered by several Czech patents. The Doly Bílina Coal Company is currently manufacturing about 3000 tons per year of sodium humate.

7.12 Coal Combustion By-Products

Increased cost and regulation are making the disposal of coal ash and calcium sulfate scrubber wastes an increasingly undesirable option in the United States and many other places. Only 31% of the coal ash and slag produced in the United States in 1991 was beneficially used, and only 1.9% of the scrubber waste was used (American Coal Ash Association, 1991). Several countries in the European Union have a strong emphasis on coal ash utilization and achieve remarkably high levels of beneficial use, including the Netherlands (100% utilization) and Denmark (90% utilization) (Clarke, 1993). The quality characteristics of coal combustion by-products vary widely at present and will become more diverse in the future with the increased application of FGD, FBC, and gasification combined-cycle systems. There are important environmental and economic benefits to be gained from the increased utilization of coal by-products and other waste materials as resources. Environmental benefits are obtained from reduced solid waste, conservation of natural resources, and reduced energy consumption and CO_2 generation where by-products can be substituted for energy-intensive primary products such as portland cement. Economic benefits include reduced construction costs, savings in ash handling and disposal costs, and the creation of marketing opportunities for by-product sales.

The value of many coal combustion by-products has been well established by research and commercial practice (Manz, 1984, 1985, 1993). As an engineering construction material (e.g., cement replacement), they enhance strength and durability while reducing cost. In agriculture and mine land reclamation, ash and gypsum by-products can improve the tilth of deficient soils and provide some plant nutrients. In waste stabilization, their pozzolanic and cementitious properties can be used to immobilize hazardous nuclear, organic, and toxic metal wastes for safe environmental disposal. Numerous products can be manufactured from coal combustion by-products, including blended cements, gypsum, aggregate, concrete block, and other cast concrete products, mineral wool, brick and other ceramic products, fillers for metal and plastic products, and even paint. Specialized construction applications include road base, controlled-strength fill, and marine applications in break waters and piers. In all of these applications, it is vitally important to match the properties of the coal by-product with the requirements of the application.

Product specifications for coal by-product application should address environmental, engineering, and economic performance criteria together rather than separately. The environmental safety of a range of coal combustion by-products has already been determined, with the overwhelming weight of evidence indicating that these products are generally not hazardous under regulatory definitions and that they pose no greater concern than a large number of common solid materials, including cement, rock, and soil (Schwartz et al., 1993; Smith, 1991; Hassett et al., 1991, 1993). However, for particular coal combustion by-products or sources that have not been environmentally tested for beneficial use, additional validation may be required before unrestricted use for a class of application can be approved. Engineering and economic performance criteria should be pursued through standards organizations (e.g., ASTM in the United States), government agencies that are potential by-product users (e.g., the Highway Administration), and universities performing technology-based research and development.

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