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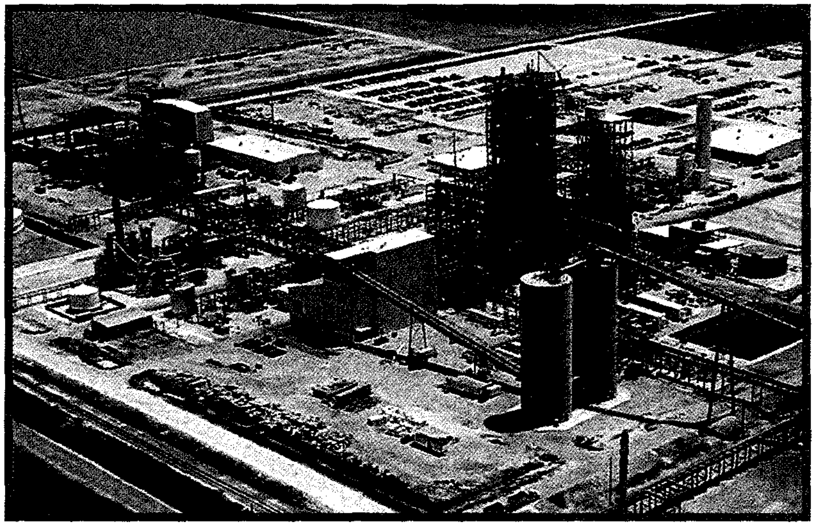
Fifth Annual Clean Coal Technology Conference

TECHNICAL PAPERS

Powering the Next Millennium



Hyatt Regency Westshore
January 7-10, 1997, Tampa, Florida

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Photograph

Tampa Electric Company's Integrated
Gasification Combined-Cycle Plant
(Polk Power Station)

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Fifth Annual Clean Coal Technology Conference

Technical Papers

January 7-10, 1997
Tampa, Florida

Powering the Next Millennium

The Fifth Annual Clean Coal Technology Conference will focus on presenting strategies and approaches that will enable clean coal technologies to resolve the competing, interrelated demands for power, economic viability, and environmental constraints associated with the use of coal in the post-2000 era. The program will address the dynamic changes that will result from utility competition and industry restructuring, and to the evolution of markets abroad. Current projections for electricity highlight the preferential role that electric power will have in accomplishing the long-range goals of most nations. Increased demands can be met by utilizing coal in technologies that achieve environmental goals while keeping the cost-per-unit of energy competitive. Results from the projects in the DOE Clean Coal Technology Demonstration Program confirm that technology is the pathway to achieving these goals.

The industry/government partnership, cemented over the past 10 years, is focussed on moving the clean coal technologies into the domestic and international marketplaces. The Fifth Annual Clean Coal Technology Conference will provide a forum to discuss these benchmark issues and the essential role and need for these technologies in the post-2000 era.

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Advanced Coal Process Systems

The Liquid Phase Methanol (LPMEOH™) Process Demonstration at Kingsport

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Abstract

The Liquid Phase Methanol (LPMEOH™) process uses a slurry bubble column reactor to convert syngas (primarily a mixture of carbon monoxide and hydrogen) to methanol. Because of its superior heat management, the process is able to be designed to directly handle the carbon monoxide (CO) - rich syngas characteristic of the gasification of coal, petroleum coke, residual oil, wastes, or of other hydrocarbon feedstocks. When added to an integrated gasification combined cycle (IGCC) power plant, the LPMEOH™ process converts a portion of the CO-rich syngas produced by the gasifier to methanol, and the remainder of the unconverted gas is used to fuel the gas turbine combined-cycle power plant. The LPMEOH™ process has the flexibility to operate in a daily electricity demand load-following manner. Coproduction of power and methanol via IGCC and the LPMEOH™ process provides opportunities for energy storage for electrical demand peak shaving, clean fuel for export, and/or chemical methanol sales.

Introduction

The LPMEOH™ technology was developed during the 1980's, with the financial support of the U. S. Department of Energy (DOE). The concept was proven in over 7,400 hours of test operation in a DOE-owned, 3,200 gallons (U.S.) of methanol per day process development unit located at LaPorte, Texas. (Ref. a). The commercial-scale demonstration plant for the technology has been constructed and is now being commissioned at Eastman Chemical Company's coal gasification facility in Kingsport, Tennessee under the DOE's Clean Coal Technology Program. The LPMEOH™ plant will demonstrate the production of at least 80,000 gallons of methanol per day, and will simulate operation for the IGCC coproduction of power and methanol application. Construction began in October of 1995 and was completed in December of 1996. Commissioning will be completed and startup will begin in January of 1997, and will be followed by four years of operation to demonstrate the commercial advantages of the technology.

Air Products and Eastman formed the "Air Products Liquid Phase Conversion Co., L.P." partnership to execute the demonstration project. The partnership owns the LPMEOH™ demonstration plant. Air Products manages the demonstration project and provides technology analysis and direction for the demonstration. Air Products also provided the design, procurement, and construction of the LPMEOH™ demonstration plant (i.e., a turnkey plant). Eastman provides the host site, performs the permitting and operation of the LPMEOH™ unit, and supplies the supporting auxiliaries, the synthesis gas, and takes the product methanol.

The LPMEOH™ plant will demonstrate production of at least 80,000 gallons of methanol per day, from a portion of the available clean synthesis gas. Most of the product methanol will be refined to chemical-grade quality (99.85 wt % purity via distillation) and used by Eastman as replacement chemical feedstock in the commercial facility. A portion of the product methanol will be withdrawn prior to purification (about 98 wt % purity) and used in the off-site product-use tests.

This paper gives a review of: I - Commercial Application for the LPMEOH™ process technology; II - Demonstration Plant - Test Plans, highlighting the operational and product-use testing plans to confirm the commercial application; and III - Demonstration Plant Design, Construction and Startup - Status, highlighting the design and integration of the demonstration plant at Kingsport, and of the accomplishments during the design and construction phase.

I - Commercial Application

Technology Description

The heart of the LPMEOH™ process is the slurry bubble column reactor (Figure 1).

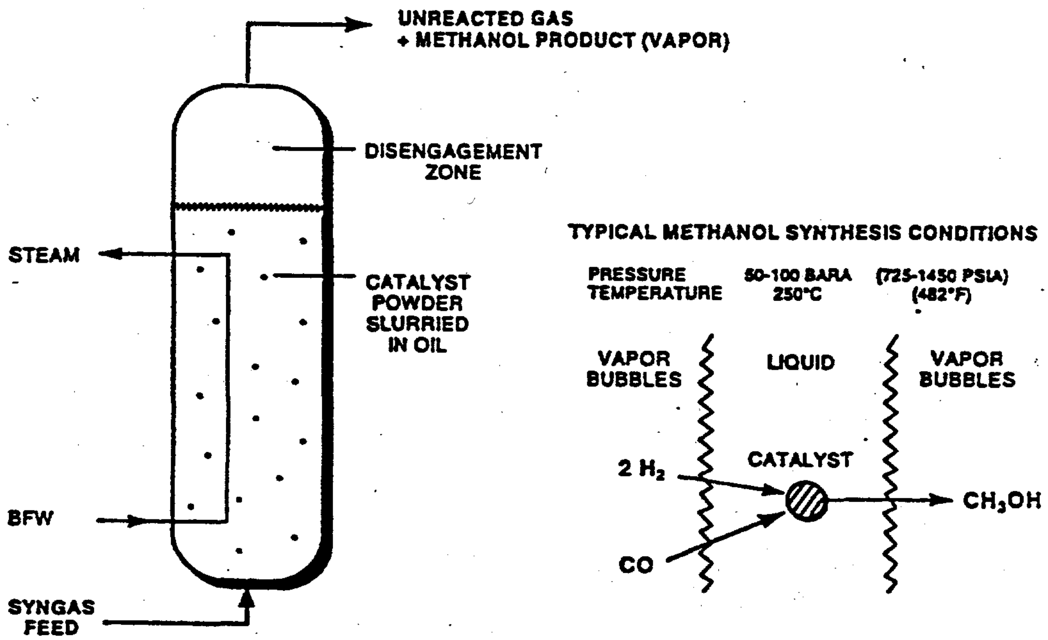

Figure 1. LPMEOH™ Reactor and Reaction Schematics

The liquid medium is the feature that differentiates the LPMEOH™ process from conventional technology. Conventional methanol reactors use fixed beds of catalyst pellets and operate in the gas phase. The LPMEOH™ reactor uses catalyst in powder form, slurried in an inert mineral oil. The mineral oil acts as a temperature moderator and a heat removal medium, transferring the heat of reaction from the catalyst surface via the liquid slurry to boiling water in an internal tubular heat exchanger. Since the heat transfer coefficient on the slurry side of the heat exchanger is relatively large, the heat exchanger occupies only a small fraction of the cross-sectional area of the reactor. The slurry reactor can thus achieve high syngas conversion per pass, due to its capability to remove heat and maintain a constant, highly uniform temperature through the entire length of the reactor.

Because of the LPMEOH™ reactor's unique temperature control capabilities, it is able to directly process syngas which is rich in carbon oxides (carbon monoxide and carbon dioxide). Gas phase methanol technology would require such a feedstock to undergo stoichiometry adjustment by the water gas shift reaction (to increase the hydrogen content) and carbon dioxide (CO_2) removal (to reduce the excess carbon oxides). In a gas phase reactor, temperature moderation is only achieved by recycling large amounts of hydrogen (H_2)-rich gas, utilizing the higher heat capacity of H_2 gas as compared to carbon monoxide (CO) gas. Typically a gas phase reactor is limited to about 16% CO gas in the inlet to the reactor, in order to limit the conversion per pass to avoid excess heating. In contrast, with the LPMEOH™ reactor, CO gas concentrations in excess of 50% have been routinely tested without any adverse effect on the catalyst activity.

A second differentiating feature of the LPMEOH™ reactor is its robust character. The slurry reactor is suitable for rapid ramping, idling, and even extreme stop/start actions. The thermal moderation provided by the liquid inventory in the reactor acts to buffer sharp transient operations that would not normally be tolerable in a gas phase methanol synthesis reactor.

A third differentiating feature of the LPMEOH™ process is that a high quality methanol product is produced directly from syngas which is rich in carbon-oxides. Gas phase methanol synthesis, which relies on hydrogen-rich syngas, results in a crude methanol product with to 4 to 20% water by weight. The product from the LPMEOH™ process typically contains only 1% water by weight. This methanol product, coproduced with IGCC, is therefore suitable for many applications, and at a substantial savings in purification costs. The steam produced in the LPMEOH™ reactor is suitable for purification of the methanol product (for upgrading to a higher quality) or for use in the IGCC power generation cycle.

Another unique feature of the LPMEOH™ process is the ability to add fresh catalyst on-line. Methanol catalyst deactivates at a slow rate. With the LPMEOH™ reactor, spent catalyst slurry may be withdrawn and fresh catalyst slurry added on a periodic batch basis. This allows continuous, uninterrupted operation and also the maintenance of a high productivity level in the reactor. Furthermore, choice of replacement rate permits optimization of productivity versus catalyst replacement cost.

IGCC Coproduction Options

The LPMEOH™ process is a very effective technology for converting a portion of the H_2 and CO in an IGCC electric power plant's coal-derived syngas to methanol. The process is very flexible in being able to process many variations in syngas composition. The LPMEOH™ process can be used with an IGCC electric power plant (Ref. b), to provide the once-through methanol production as depicted in Figure 2. The process can be designed to operate in a continuous, baseload manner, converting syngas from oversized gasifiers or from a spare gasifier. The process can also be designed to operate only during periods of off-peak electric power demand to consume a portion of the excess syngas and allow the electricity output from the combined-cycle power unit to be turned down. In this latter circumstance, the gasification unit continues to operate at full baseload capacity, so the IGCC facility's major capital asset is fully utilized. In either baseload or cycling operation, partial conversion of between 20% and 33% of the IGCC plant's syngas is optimal, and conversion of up to 50% is feasible.

The design configuration for the LPMEOH™ process depends upon the degree of conversion of syngas (or the quantity of methanol relative to the power plant size). The feed gas pressure is a prime determinant of the degree of syngas conversion, as shown in Figure 3. Reaction pressure for methanol synthesis design is usually 750 psia or higher.

In its simplest configuration, syngas (feed gas) at its maximum available pressure from the IGCC electric power plant is passed once, without recycle through the LPMEOH™ plant (Figure 4), and partially converted to methanol. The unreacted gas is returned to the IGCC power plant's combustion turbines.

Of course, the richer the once-through syngas is in CO, the more the production is limited by the availability of H_2. Normally the least expensive methanol conversion cost comes from converting as much hydrogen as is practical; without feed gas compression, unreacted gas recycle or further processing of the feed gas. The higher the pressure at which the syngas is available, the greater is the degree of conversion and the lower the conversion cost.

If greater amounts of syngas conversion are required, different once-through plant design options (Figure 4) are available. There is still no need for upstream stoichiometric adjustment of the feed gas by the water-gas shift reaction and CO_2 removal; so the simplicity of once-through CO-rich gas processing is retained. The LPMEOH™ process design options for greater syngas conversion are:

- Once-Through, with Gas Recycle.

One design technique to increase the degree of syngas conversion is to condense out methanol from the reactor effluent and to recycle part of the unreacted feed gas back to the reactor inlet. With the LPMEOH™ process, this simple recycle refers to recycle of CO-rich gas. The recycle ratio required for the LPMEOH™ is moderate, for example, one part unreacted syngas to one part fresh feed gas. This 1 to 1 recycle ratio is usually quite effective in optimizing the methanol production. At higher recycle ratios, little is gained, since most of the available H_2 has already been converted to methanol.

- Once-Through, with Water Addition

If additional conversion is desired, the LPMEOH™ process design can be altered to generate additional H_2. The inherent shift activity of the methanol catalyst can be utilized to accommodate a modest amount of shift activity within the reactor. This is done by the addition of water, as steam, to the syngas before it passes through the liquid phase methanol reactor. Within the reactor, the additional steam is converted to H_2, which is, in turn, converted to methanol. In the water addition case, the increase in conversion is accompanied with a modest increase of water in the crude methanol product and of CO_2 in the reactor effluent gas.

- Once-Through, with Feed Gas Compression

When the feed gas pressure from the IGCC electric power plant is low (e.g. below 750 psia), feed gas compression may be added to the LPMEOH™ process design, to increase reactor productivity and the overall conversion of syngas to methanol.

Baseload Coproduction of Methanol and Power

Process design study work for the LPMEOH™ process has been directed towards converting a portion of coal-derived syngas produced in an IGCC electric power plant to methanol. A feed gas containing 35% H_2, 51% CO, 13% CO_2 and 1% inerts (nitrogen) was used for preparing the baseload methanol coproduction economics.

With a given gasification plant size, the IGCC coproduction plant can be designed to accommodate a range of methanol to power output ratio's. For example (Ref. c, d), a gasification plant, with two gasifiers of 1735 million Btu (HHV) per hour output each, could be sized for baseload power output of 426 megawatts of electricity (MWe) and for baseload methanol coproduction of 152,000 US gallons per day (G/D). Other methanol and power plant size options for this gasification plant size, are shown in Table 1.

Table 1. Methanol Plant to Power Plant Size Ratio

% of Syngas Converted to Methanol (%)	Baseload Power Plant Size (MWe)	Baseload Methanol Plant Size (G/D)	Methanol Plant to Power Plant Size Ratio (G/D per MWe)
0	500	0	0
13.8	426	152,000	357
20.0	394	210,000	533
30.0	342	330,000	965

The IGCC coproduction plant with 426 MWe of power and 152,000 G/D of methanol is used for the baseload production cost estimate for coproduced methanol, shown in Table 2. If the baseload fuel gas value is $4.00 per million Btu, then 152,000 G/D of methanol can be coproduced from coal for under 50 cents per gallon.

As one would expect, the methanol production cost is lower at larger methanol plant sizes. Figure 5, shows the effect of plant size for once-through methanol coproduction. Methanol production costs for two of the LPMEOH™ plant design options for higher syngas conversion: 1 to 1 gas recycle, and 1 to 1 gas recycle with water addition, are also shown.

Today, new methanol plants are being built where natural gas is inexpensive (Chile, Saudi Arabia). These new world scale plants range in size from 700,000 to 900,000 G/D (2000 to 2700 metric tons per day) in size. The economy of scale savings; in natural gas gathering, syngas manufacturing, and in methanol storage and ocean transport facilities; drive these plants to their large size. Estimates (Ref. e, f) show that an 836,000 G/D off-shore methanol plant (with the same, 20% per year capital charge as in Table 1 and Figure 5), with natural gas at $0.50 to $1.00 per million Btu, has a total ex-plant methanol production cost of 46 to 50 cents per gallon. Adding ocean freight, duty and receiving terminal storage typically adds 8 to 10 cents per gallon; giving a total delivered U.S. Gulf Coast methanol cost (Chemical Grade) of 55 to 60 cents per gallon.

Figure 5 is interesting, because it provides an unexpected result. Methanol coproduction with IGCC and the once-through LPMEOH™ process, does not need large methanol plant sizes to achieve good economies of scale. The gasification plant is already at a large economical scale for power generation;. so the syngas manufacturing economies are already achieved. Methanol storage and transport economies are also achieved by serving local markets, and achieving freight savings over the competing methanol, which is usually shipped from the U. S. Gulf coast.

The 50 cents per gallon coproduction cost for a 152,000 G/D once-through LPMEOH™ plant size is competitive in local markets with new world scale off-shore methanol plants. Figure 5 shows an additional 3 to 4 cent per gallon saving for a 365,000 G/D LPMEOH™ plant size. These additional savings might be used to off-set higher freight costs to more distant local customers; while still maintaining a freight and cost advantage over the imported methanol from the Gulf Coast.

Applications for the Coproduced Methanol Product

The methanol coproduction process studies show that the LPMEOH™ process can produce a clean high quality methanol product at less than 50 cents per gallon; from an abundant, non-inflationary local fuel source (coal). Serving local markets, the methanol coproduced at central IGCC electric power plants, can be a valuable premium fuel or fuel feedstock for many applications, such as:

1. An economical hydrogen source for small fuel cells, which are being developed for transportation applications. Methanol is a storable, and transportable, liquid fuel which can be reformed under mild conditions to provide an economical source of hydrogen for fuel cells.
2. When reformed under mild conditions, may be an economical hydrogen or carbon monoxide source for industrial applications.
3. A substitute for chemical grade methanol being used for MTBE manufacture. (MTBE is added to gasoline to boost octane and to meet environmental clean air mandates. MTBE is one of the major current markets for methanol.)
4. An environmentally advantaged fuel for dispersed electric power stations. Small packaged power plants (combustion turbine, internal combustion engine, or fuel cell) provide power and heat locally, at the use point; eliminating the need for natural gas pipelines and high voltage power lines.
5. Finally, the coproduced methanol may be used by the utility owning the IGCC facility (see Figure 2). Potential uses are: a) as a backup fuel for the IGCC plant's main gas turbines; b.) as a fuel for a separate, dedicated cycling combined-cycle unit at the same site; c.) as the fuel exported to the utility's distributed power generation system(s); or d) as the transportation fuel for the utility's bus or van pool. Since methanol is an ultra-clean (zero sulfur) fuel which burns with very low (better than natural gas) emissions of nitrogen oxides, the incremental power is very clean. Since the methanol is derived from the coal pile, the IGCC facility can be truly independent and self-sufficient for fuel needs. In addition, should the external prices for methanol command higher value to the IGCC plant's owner, the methanol can be exported for additional revenues.

Many of the applications listed above, are embryo developments. Their ultimate market size potential; for transportation applications, for industrial applications and for distributed power generation; could become large. The methanol product specification for the five applications is not adequately known. Therefore, part of the LPMEOH™ demonstration project's program is to confirm the suitability of the methanol product for these (and other) uses. Product-use tests will be used to develop final methanol product specifications. During the demonstration, in the 1998 to 2000 time-frame, about 400,000 gallons of the "as-produced from CO-rich syngas" methanol will be available for off-site product-use testing. The final off-site product-use test plan is now under development. More details will be provided to interested parties.

II - Demonstration Plant - Test Plans

Objective

The LPMEOH™ Process technology is expected to be commercialized as part of an IGCC electric power generation system. The preceding Commercial Application section highlighted the advantages of the LPMEOH™ process. These commercial advantages must be demonstrated and confirmed during operations. Therefore, the demonstration test plan incorporates, but is not limited to, these commercially important aspects of IGCC integration:

- The coproduction of electric power and of added value liquid transportation fuels and/or chemical feedstocks from coal. This coproduction requires that the partial conversion of syngas to storable liquid products be demonstrated.
- Using an energy load-following operating concept which allows conversion of off-peak energy, at attendant low value, into peak energy commanding a higher value. This load-following concept requires that on/off and syngas load-following capabilities be demonstrated.
- Syngas compositions will vary with the type of gasification process technology and gasification plant feed used in the power generation application. Therefore, operation over a wide variety of syngas compositions will be demonstrated.
- Catalyst life, operating on "real" coal-derived syngas, must be demonstrated over a long period of time. Major parameters include reactor operating temperature, concentration of poisons in the reactor feed gas, and catalyst aging and attrition.
- Reactor volumetric productivity must be optimized for future commercial designs. Parameters include: high inlet superficial velocity of feed gas, high slurry catalyst concentration, maximum gassed slurry level, and removal of the heat of reaction.
- Methanol Product, as produced from by the liquid phase reactor from syngas rich in carbon oxides, must be suitable for its intended uses. Off-site methanol product-use testing will confirm the product specification needed for market acceptability.

Methanol Operations - Demonstration Test Plan

Three key results will be used to judge the success of the LPMEOH™ process demonstration during the four years of operational testing:

- Resolution of technical issues involved with scaleup and first time demonstration for various commercial-scale operations
- Acquisition of sufficient engineering data for commercial designs; and
- Industry acceptance.

The demonstration test plan has been established to provide flexibility in order to meet these success criteria. Annual operating plans, with specific targeted test runs, will be prepared, and revised as necessary. These plans will be tailored to reflect past performance, as well as commercial needs. User involvement will be sought.

The LPMEOH™ operating test plan outline, by year, is summarized in Table 3. The demonstration test plan encompasses the range of conditions and operating circumstances anticipated for methanol coproduction with electric power in an IGCC power plant. Since Kingsport does not have a combined-cycle power generation unit, the tests will simulate the IGCC application. Test duration will be emphasized in the test program. The minimum period for a test condition, short of the rapid ramping tests, is 2 weeks. Numerous tests will have 3–6 week run periods, some 8–12 weeks, and a few key basic tests of 20 to 30 weeks.

Table 3.	**LPMEOH™ Demonstration Test Plan Outline**
Year 1	Catalyst Aging
	Catalyst Life Versus LaPorte process development unit and Lab Autoclaves
	Process Optimization / Maximum Reactor Productivity
	Catalyst Slurry Concentration
	Reactor Slurry Level
	Catalyst Slurry Addition Frequency Test
	Establishment of Baseline Condition
Years 2 & 3	Catalyst Slurry Addition and Withdrawal at Baseline Condition
	Catalyst Attrition/Poisons/Activity/Aging Tests
	Simulation of IGCC Coproduction for:
	1. Synthesis Gas Composition Studies for Commercial Gasifiers
	Texaco, Shell, Destec, British Gas/Lurgi, Other Gasifiers
	2. IGCC Electrical Demand Load Following:
	Rapid Ramping, Stop/Start (Hot and Cold Standby).
	3. Additional Industry User Tests
	Maximum Catalyst Slurry Concentration
	Maximum Throughput/Production Rate
Year 4	Stable, extended Operation at Optimum Conditions
	99% Availability
	Potential Alternative Catalyst Test
	Additional Industry User Tests

Table 3 - Demonstration Test Plan Outline

III - Demonstration Plant Design, Construction and Startup - Status.

Kingsport Site

Eastman began coal gasification operations at Kingsport in 1983. Figure 6 shows an aerial view of Eastman's Kingsport gasification facility. Texaco gasification is used to convert about 1,000 tons-per-day of high-sulfur, Eastern bituminous coal to synthesis gas for the manufacture of methanol, acetic anhydride, and associated products. Air Products provides the oxygen for gasification by a pipeline from an over-the-fence air separation unit. The crude synthesis gas is quenched, partially shifted, treated for acid gas removal (hydrogen sulfide and carbonyl sulfide, and CO_2, via Rectisol), and partially processed in a cryogenic separation unit to produce separate H_2 and CO streams. The H_2 stream is combined with clean synthesis gas to produce stoichiometrically balanced feed to a conventional gas phase methanol synthesis unit. Methanol from this unit is reacted with recovered acetic acid to produce methyl acetate. Finally, the methyl acetate is reacted with the CO stream to produce the prime product, acetic anhydride (and acetic acid for recycle).

Because the gasification facility produces individual streams of clean synthesis gas, CO, and H_2-rich gas, there is the capability to blend gases and mimic the gas compositions of a range of gasifiers. Figure 7 shows the process block flow diagram for the Kingsport gasification facility including the LPMEOH™ demonstration plant.

Demonstration Plant Design

The site at Kingsport borders an existing methyl acetate plant, and was relatively level. Figure 8 is an aerial view of the site prior to the start of construction. Some fill was required to provide a 270 ft. by 180 ft. plot for the demonstration plant and tank truck loading areas. An area next to the site was made available for establishing the construction trailer, fabrication, and laydown areas. The job site was fenced off in order to provide a secure site separate from the operating areas of the Eastman facility.

Air Products' Gas Group Engineering Department was responsible for the engineering design and construction of the project. This included detailed design and procurement. Eastman was responsible for the outside battery limits design and construction, the permitting, and for providing the digital control programming. Eastman reviewed the detailed design of the demonstration plant. Most of the equipment and materials were bid competitively from combined Air Products and Eastman developed bid lists. The construction was subcontracted into ten different packages, awarded on fixed priced bidding.

The need to meet all of the test program objectives provided a design challenge for the Air Products/Eastman design team. Of primary importance was the integration of the LPMEOH™ demonstration plant within the Kingsport gasification complex. Since the feed composition to the reactor is to be varied from H_2-lean to H_2-rich (25% to 70+%

H_2) and the flow to the reactor by at least a factor of two, all of the product and byproduct streams within and outside the battery limits were affected. Control valves and instrumentation for the demonstration plant were required to have functionality over and beyond those for a normal commercial facility. Extreme cases of about twenty different heat and material balances were considered for specification of each piece of equipment, flow measurement device, control valve, and safety relief device.

Machinery specification was especially challenged by the requirements of the demonstration operating period. The syngas recycle compressor design uniquely considered all of these varying molecular weight streams in tandem with the varying pressure drop requirements. These extremely atypical operating requirements challenged controls and machinery engineers to develop a robust surge control strategy which could adequately protect the compressor. Slurry pump design also considered a wide range of operating conditions, such as changing temperature and viscosity due to varying slurry concentrations.

The heart of the LPMEOH plant is the reactor. The design and fabrication of the reactor vessel and its internal heat exchanger received careful attention. The reactor size is based on a scale-up of the DOE-owned process development unit at LaPorte, Texas. The reactor is a stainless steel clad carbon steel vessel designed for 1000 psig and 600°F. The detail design and materials delivery for the reactor were not a problem. The reactor has an internal heat exchanger for removal of the heat of reaction. The design of the internal heat exchanger required careful analysis of the headers and support system. The fabrication of the bundle required special procedures for welding the tubes in place prior to insertion within the reactor.

The analysis to be performed during the demonstration period requires the collection of high quality engineering data. The gas analysis system is "research quality" in terms of analysis capabilities (number of components and precision) and is also rugged enough to withstand an industrial operating environment. Duplicate flow measurement devices were frequently required to ensure accurate measurement during some of the off-design cases. Temperature and pressure measurement devices over and above what would be required for a commercial plant were installed. All of this data will be processed and stored using a state of the art data acquisition system, Honeywell Total Plant™, which will be integrated with the facility's distributed control system. This system will also provide engineers with remote access to data.

The ultimate goal of the demonstration period is to reach a stable optimized operating condition, with the best combination of the most aggressive operating parameters. These parameters, such as reactor superficial gas velocity, slurry concentration and reactor level, will allow us to maximize the reactor productivity. It will be a continuing goal during the demonstration period to determine and debottleneck limitations of the demonstration plant.

Project Schedule

The DOE approved the site change of the LPMEOH Demonstration to Eastman's Kingsport, TN site in October of 1993. Air Products and Eastman worked with the DOE to define the size of the plant and develop a Statement of Work for the LPMEOH™ Demonstration at Kingsport. This Project Definition phase including a cost estimate was completed in October of 1994. Preliminary Detail Design work on equipment layouts and development of P&ID's began shortly after this. Full authorization from the DOE for Design and Construction was effective February 1, 1995. The reactor was the first piece of equipment to be placed on order in November of 1994. Equipment deliveries began in November of 1995. The State air permit was received in March of 1996.. The DOE completed its National Environmental Policy Act (NEPA) review and issued a Finding of No Significant Impact (FONSI) in June of 1995. Construction at the site began in October of 1995. Construction manpower peaked at 150 people on site in mid-November of 1996. Construction was essentially completed in December of 1996. The overall schedule from authorization to startup was 23 months.

Instrument Loop Checking began in October 1996. Commissioning began in December of 1996, and startup will begin in late January of 1997. The four-year methanol test operation will begin in February of 1997. The operating test program will end in the year 2001. The off-site fuel use tests will be performed over an 18 to 30 month period, beginning in May of 1998.

Conclusion

The LPMEOH™ process is now being demonstrated at commercial scale, under the DOE Clean Coal Technology Program. The demonstration plant, located at Eastman Chemical Company's Kingsport, Tennessee coal gasification facility site, will produce at least 80,000 gallons-per-day of methanol from coal-derived synthesis gas. Startup begins in late January of 1997, followed by a four-year demonstration test period beginning in late February of 1997.

Successful demonstration of the LPMEOH™ technology will add significant flexibility and dispatch benefits to IGCC electric power plants, which have traditionally been viewed as strictly a baseload power generation technology. Now, central clean coal technology processing plants, making coproducts of electricity and methanol; can meet the needs of local communities for dispersed power and transportation fuel. The LPMEOH™ process provides competitive methanol economics at small methanol plant sizes, and a freight and cost advantage in local markets vis-à-vis large off-shore remote gas methanol. Methanol coproduction studies show that methanol at less than 50 cents per gallon can be provided from an abundant, non-inflationary local fuel source (coal). The coproduced methanol may be an economical hydrogen source for small fuel cells, and an environmentally advantaged fuel for dispersed electric power.

TABLE 2

Production Cost Estimate for Coproduced Methanol
LPMEOH Plant Capacity: 152,000 gallons per day (500 sT/D)
Capital Investment: $29 million

		Baseload
Methanol Plant Operation:	*(Hours/year)*	7884 hr/yr.
Methanol Production	*(million Gal./year)*	49.9

Methanol Production Cost	**cents/gallon**
Syngas cost:	
Feed Gas @ fuel value ($4.00/mmBtu)	98.7
Unreacted (CO-rich) gas @ fuel value ($4.00/mmBtu)	(68.4)
Sub-total; net cost of syngas converted:	**30.3**
Operating cost	
Catalyst and chemicals	2.6
Export steam	(2.9)
Utilities	0.9
Other (fixed) costs	4.0
Sub-Total; Operating Costs:	**4.6**
Capital charge @ 20% of investment per year	**11.6**
Total Methanol Production Cost:	**46.5**

Basis:
U.S. Gulf Coast Construction, 4thQ 1996 $
Includes owner costs and 30 days of Product Strorage
CO-rich feed gas from IGCC electric power plant at 1000 psia,, with 5ppm (max.) sulfur.,
Once-through LPMEOH process design with 1562 mmBtu/hr in, 1082 mmBtu out (HHV)
Excludes License and Royalty fee. Air Product's is the LPMEOH proces technology licensor.
Product methanol with 1 wt.% water; 'Chem Grade would add 4 to 5 cents per gallon.

Table 2. Production Cost Estimate for Coproduced Methanol.

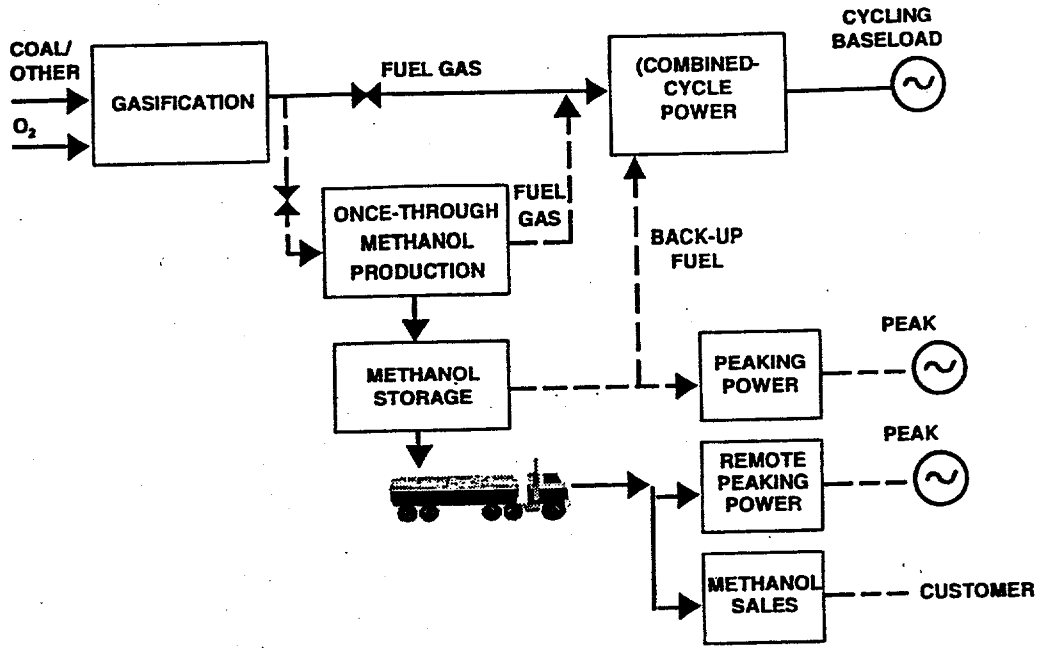

Figure 2. Once-through Methanol Coproduction with IGCC Electric Power

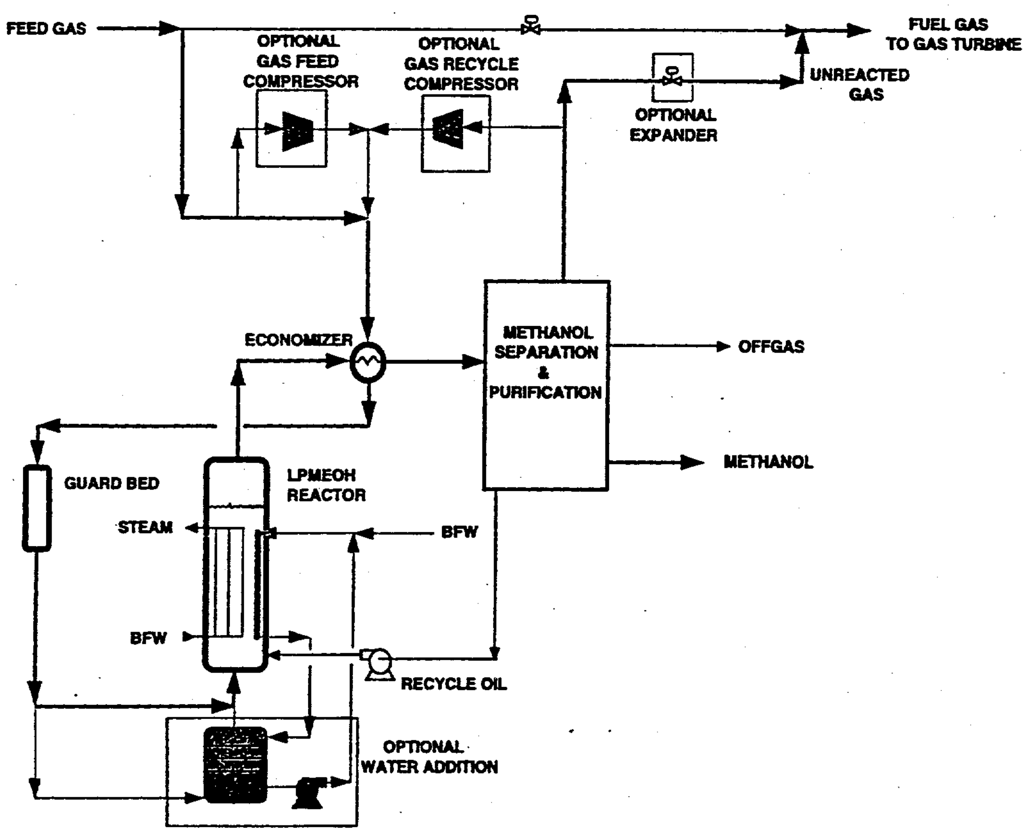

Figure 4. Once-through LPMEOH™ Process Design Options

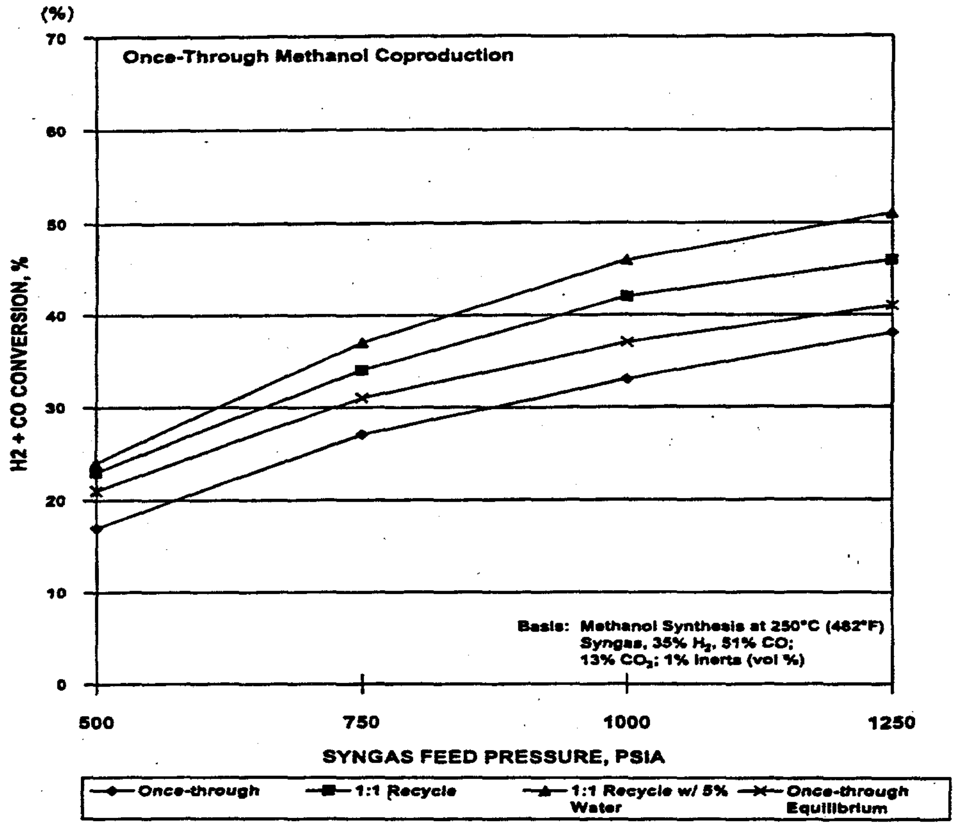

Figure 3. Synthesis Gas Conversion to Methanol

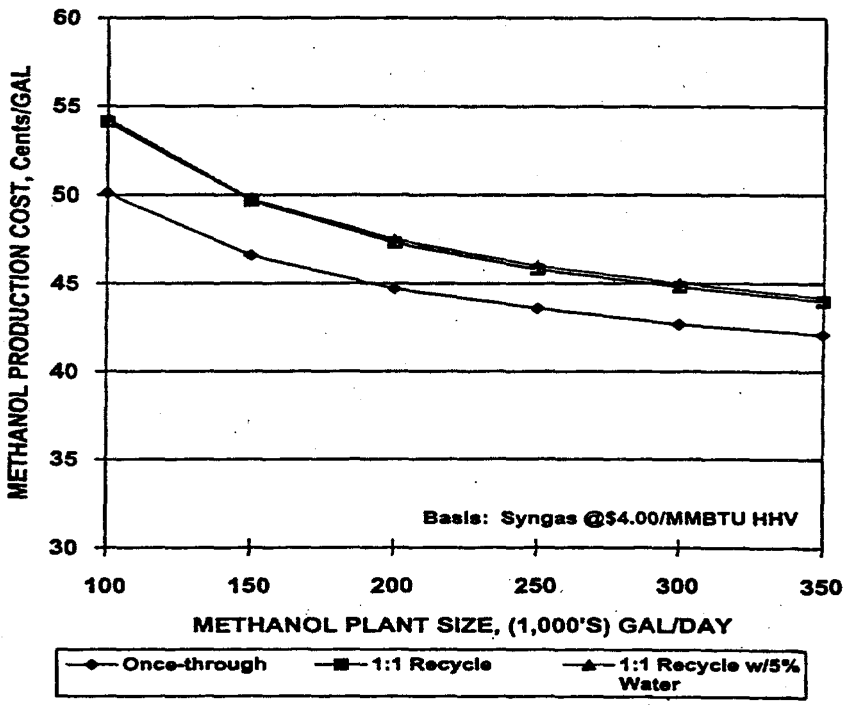

Figure 5. Coproduct Methanol Cost versus Methanol Plant Size.

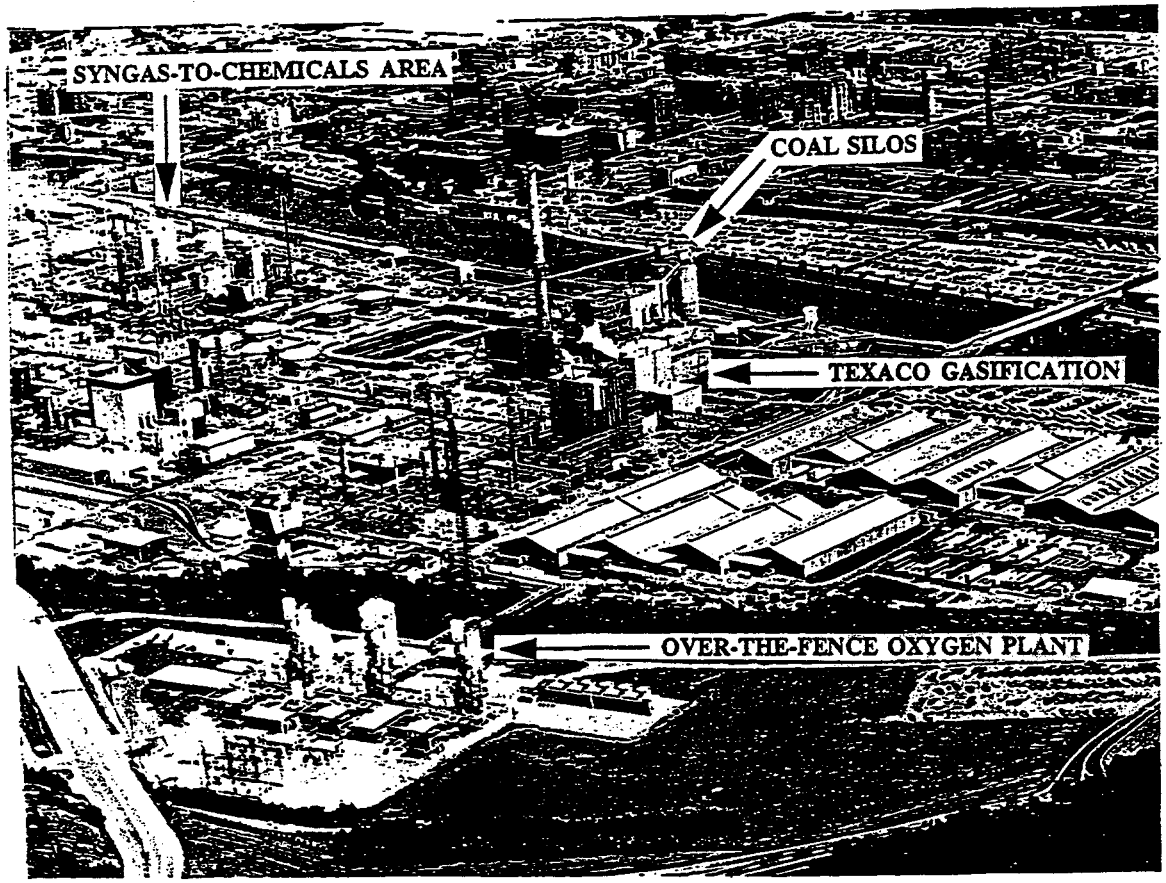

Figure 6. Aerial View of Eastman's Kingsport Complex

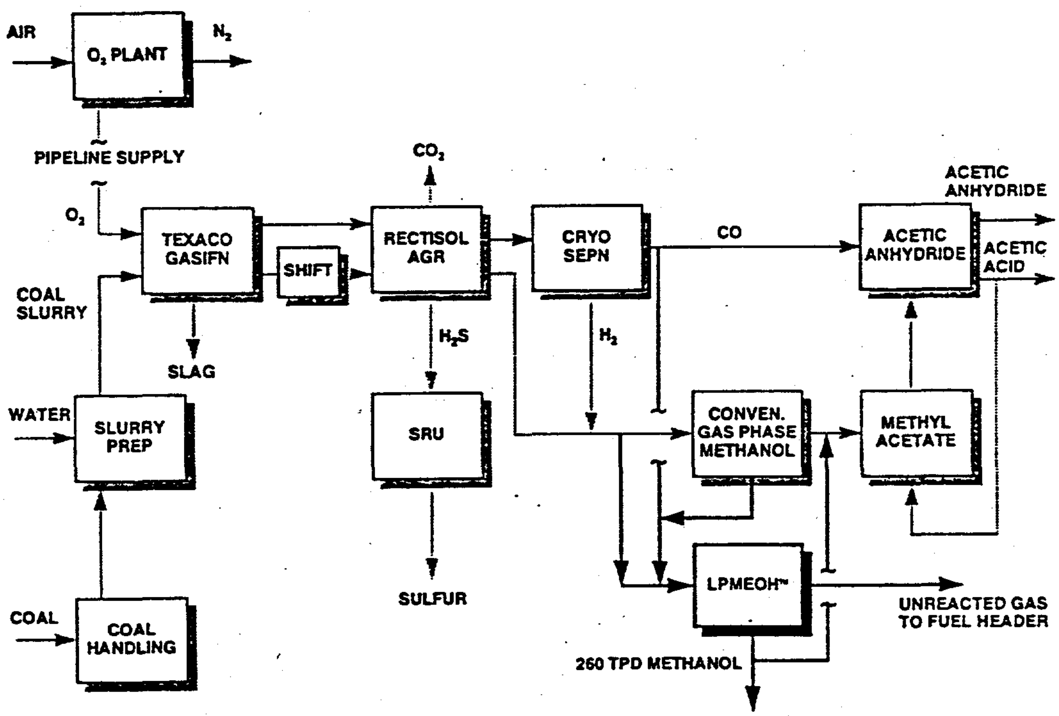

Figure 7. Process Block Flow Diagram of Kingsport Facility Including LPMEOH^{TM} Demonstration Plant.

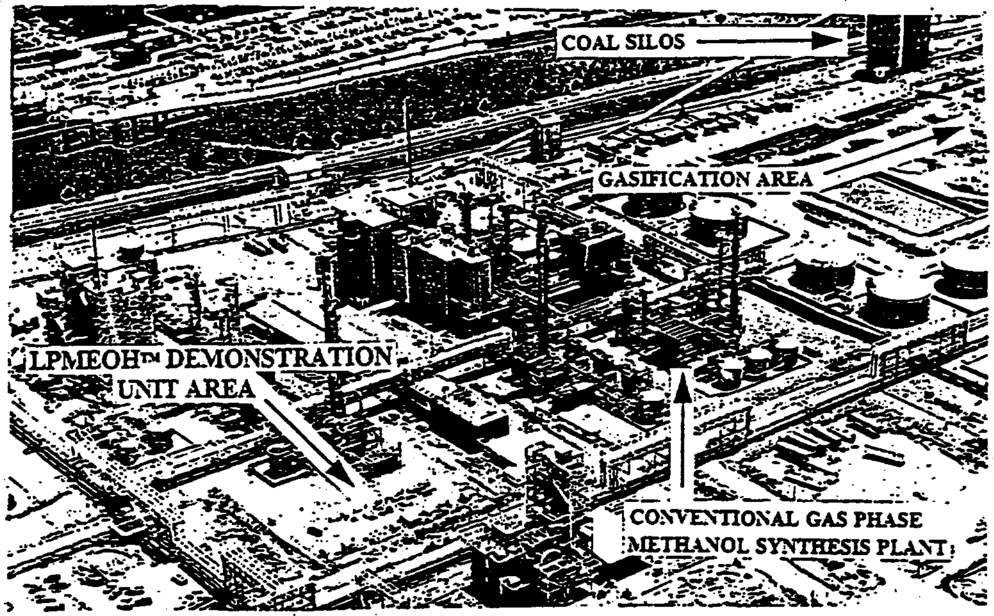

Figure 8. Aerial View of the Site for the LPMEOH™ Demonstration Plant

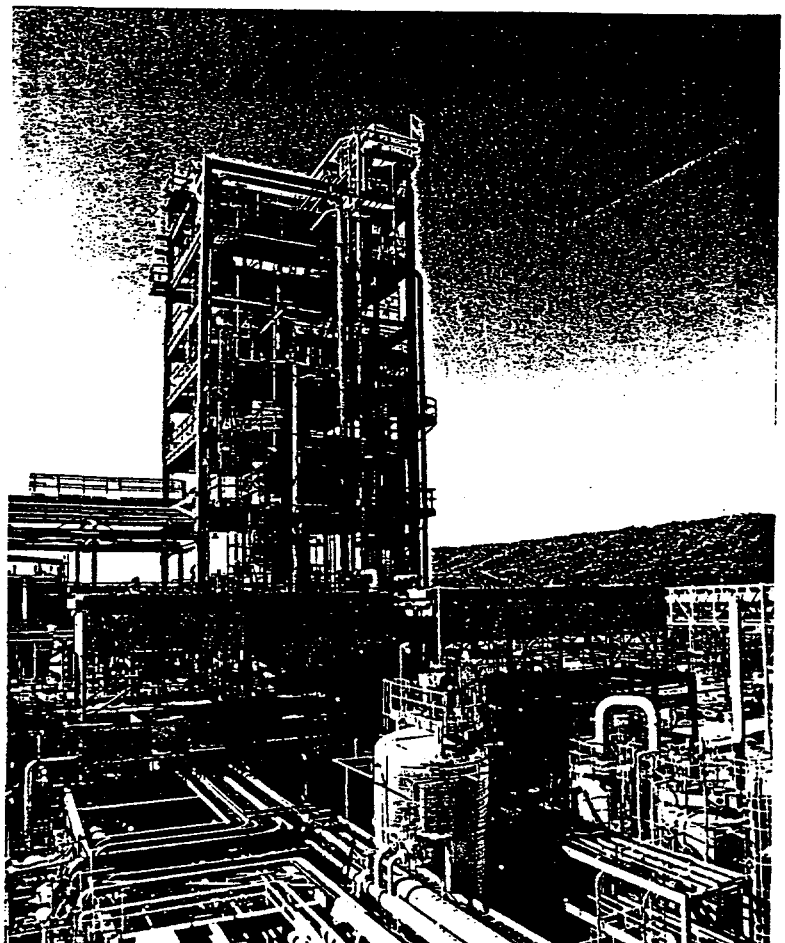

Figure 9. Photograph of the installed LPMEOH™ Demonstration Plant

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Disclaimer/Acknowledgment

Recent Experience with the CQE™

Clark D. Harrison and David B. Kehoe, CQ Inc.
David C. O'Connor, Electric Power Research Institute
G. Scott Stallard, Black & Veatch

Increasing public awareness about the health of the global environment, tightening emissions regulations, growing competition among power producers, and advances in power generation technology are transforming the business of power generation worldwide. This transformation has further complicated fuel purchase decisions that profoundly affect the cost of electricity.

CQE (the Coal Quality Expert) is a software tool that brings a new level of sophistication to fuel decisions by seamlessly integrating the system-wide effects of fuel purchase decisions on power plant performance, emissions, and power generation costs.

The result of a $21.7 million U.S. Clean Coal Technology project sponsored by the Department of Energy and the Electric Power Research Institute, CQE offers unparalleled advancements in technical capability, flexibility, and integration.

The CQE technology, which addresses fuel quality from the coal mine to the busbar and the stack, is an integration and improvement of predecessor software tools including:

- EPRI's Coal Quality Information System
- EPRI's Coal Cleaning Cost Model
- EPRI's Coal Quality Impact Model
- EPRI and DOE models to predict slagging and fouling

CQE can be used as a stand-alone workstation or as a network application for utilities, coal producers, and equipment manufacturers to perform detailed analyses of the impacts of coal quality, capital improvements, operational changes, and/or environmental compliance alternatives on power plant emissions, performance and production costs. It can be used as a comprehensive, precise and organized methodology for systematically evaluating all such impacts or it may be used in pieces with some default data to perform more strategic or comparative studies.

Overview of the Project

The CQE project was conceived by EPRI to integrate the results and products of several on-going R&D projects into computer software that would become a worldwide standard for addressing fuel-related issues in the power industry. EPRI and DOE sponsored numerous coal quality R&D projects in the late 1970s and early 1980s to carefully examine and document the answers to questions that need to be addressed before a utility can be certain that it is operating its power plants within emissions limitations at the lowest possible cost:

- What are the economics of burning a prospective coal?

- How would the delivered price of coal change if the supplier cleans or blends the coal(s) to produce a product with quality characteristics different than the coal currently delivered to the power station?

- To what degree can the quality of the coal currently delivered to the power station be changed?

- What power plant equipment and systems are most affected or limited by coal quality?

- What are the trade-offs between increased capital spending at the power stations and increased cost of fuel for higher quality?

- How will alternative emissions control strategies affect the production cost of electricity at a specific unit?

- Are the slagging and fouling consequences of burning a prospective coal affordable?

Coal producers and equipment manufacturers must also address these questions from a different perspective to assess the potential value of alternative products and services for utilities. For example, a coal producer contemplating changes to an existing cleaning plant or a manufacturer trying to sell replacement parts for coal pulverizers would both be interested in using a model that could accurately determine pulverizer performance, power consumption and maintenance costs for potential utility customers to provide a fuel that matched plant/unit capabilities and goals. CQE was conceived as the tool to serve the needs of these prospective users as well as the utilities that were already using CQIM and related EPRI and DOE software.

Background and History of the Project

In the mid 1970s, EPRI initiated its effort to understand the linkage between coal quality and power plant performance, emissions, and economics. Initial studies focused on the potential savings in capital cost of new coal-fired power stations that would result from the use of cleaner coal (1). To quantify the costs of producing cleaner coals and to evaluate the potential for physical coal cleaning to improve the quality of U.S. coals for power generation, EPRI initiated a coal cleanability characterization program at the Coal Cleaning Test Facility (CCTF) which it constructed in 1980-81. The facility's mission also included the demonstration of emerging coal cleaning technologies to accelerate their commercial deployment.

In 1982 EPRI started a parallel effort to build a state-of-the-art computer model that would predict power plant performance, production costs, and emissions based on laboratory and bench-scale coal quality measurements. The initial effort was focused on defining the specifications for the model and assembling the proven methodologies for predicting coal quality impacts on various power plant systems and components. A complementary effort to perform laboratory, bench-scale, and pilot-scale coal quality analyses was also initiated by EPRI in the mid 1980s, and since the Coal Cleaning Test Facility became the source for most of the combustion test samples, its name was changed to the Coal Quality Development Center (CQDC).

When the DOE Program Opportunity Notice for the Clean Coal Technology Program was issued on February 17, 1986, Combustion Engineering Inc. on behalf of EPRI prepared a proposal for the development of the Coal Quality Advisor that was later renamed the Coal Quality Expert, or CQE. The project proposed by Combustion Engineering included coal cleanability characterization of selected additional U.S. coals, laboratory, bench-scale, and pilot-scale combustion testing of representative samples of the run-of-mine and clean coal; full-scale power plant testing of those coals to verify coal quality effects; and the development of the software tool that would replace pilot-scale and full-scale demonstrations in the future. The proposal by Combustion Engineering was not selected from the initial awards for Round 1 of the Clean Coal Technology Program, so EPRI proceeded with some aspects of the proposed project in the meantime.

By the time the Combustion Engineering proposal was selected for negotiations in 1988, EPRI had completed the initial version of the Coal Quality Impact Model (CQIM™) and initiated some pilot-scale and commercial power plant testing programs. The result of these efforts and the previous work done by EPRI at the CQDC (and CCTF) were contributed by EPRI to the CQE project and the scope of the project was redefined to incorporate the testing and software development work necessary to complete a rigorous and robust model.

During the course of the project from May 1990 through mid-1996, computer technology and the methodology available to measure and predict coal quality continued to advance, so CQE was developed to incorporate as many of these advancements as possible and to maintain the flexibility to incorporate new features or update existing methodologies economically in the future.

Project Organization

As EPRI's contractor with responsibility for bench-scale and pilot-scale testing to correlate coal quality characteristics to power plant performance, Combustion Engineering (now ABB CE) submitted the proposal for the CQE project to DOE. While the DOE CCT1 project award decisions were being made, EPRI engaged Black & Veatch to develop the original Coal Quality Impact Model software and Electric Power Technologies to conduct full-scale power plant coal quality impact tests. In addition, coal cleanability characterization efforts continued at the CQDC and EPRI developed plans to establish the CQDC as EPRI's wholly-owned subsidiary.

When DOE selected the CQE project for negotiation, EPRI and Combustion Engineering felt that it was appropriate for CQ Inc., EPRI's subsidiary, to integrate and manage the efforts of the project team as shown on the project organization chart, Figure 1-1.

Under this organization, both CQ Inc. and Combustion Engineering executed the Cooperative Agreement with DOE and both contractors became co-prime contractors for the project with project management and administrative duties being delegated to CQ Inc. Consequently, the project was organized so that each participating organization other than EPRI and DOE would be subcontractors to CQ Inc.

As new computer technologies developed during the project and as the definition of CQE became more defined, some logical changes were made in the project organization. All software coding responsibilities were centralized at Black & Veatch. When a decision was made to exclude the Fireside Troubleshooting Guideline from the CQE code, Karta Technologies' role on the project ended, and when CQ Inc. required assistance with the design of the coal cleaning and blending models, Decision Focus was added to the project team as another subcontractor. The roles of the University of North Dakota Energy and Environmental Research Center (UNDEERC) and PSI Technology were also expanded to include the delivery of fouling and slagging prediction methodology to Black & Veatch.

In recognition of the value of CQE to their customers and to continue their support of EPRI's and DOE's coal quality R&D programs, ABB CE willingly reduced its scope and budget on the project to provide funding for more robust slagging and fouling models for CQE. ABB CE led the efforts with UNDEERC and PSI Technology that distinguish CQE from other software tools that rely on empirical indices to indicate potential slagging and fouling problems.

In addition to its role as co-sponsor, EPRI also provided technical leadership to the project for the pilot-scale and full-scale power plant testing programs and directly managed the software development tasks. EPRI's CQIM User's Group provided a sounding board for CQE development ideas and served as a project advisory committee. Moreover, five members of the user's group served as beta test users of the prototype software.

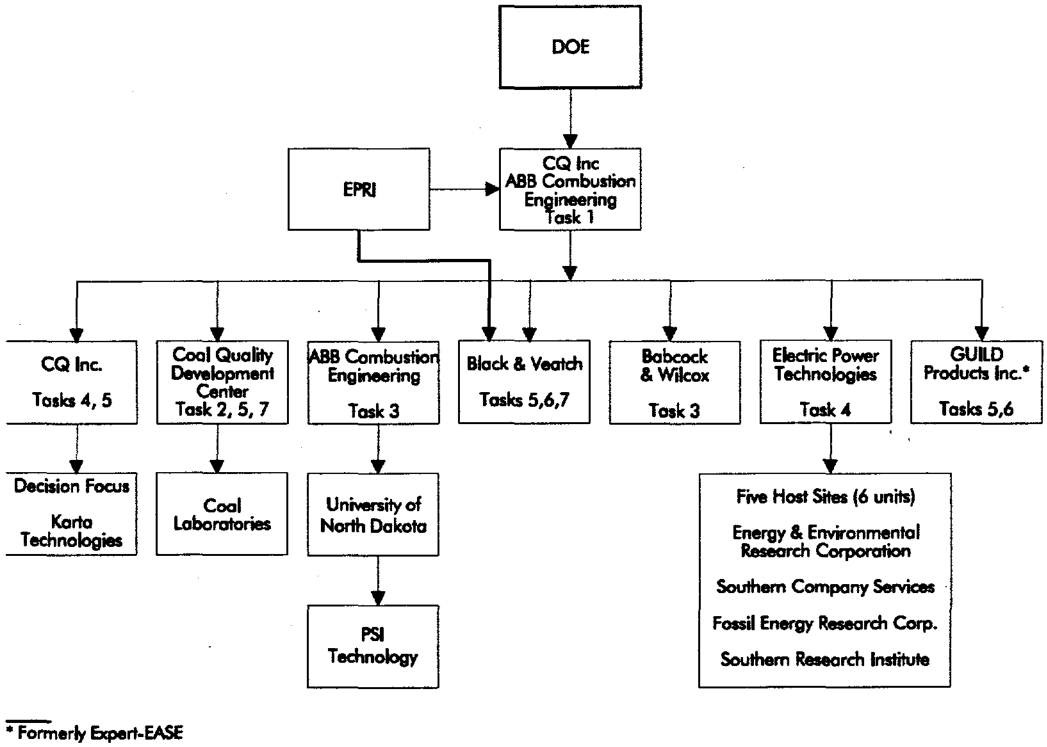


Figure 1-1
Project Organization Chart

Project Description

Although the project mission was to deliver a software tool, the scope of the project included numerous supporting tasks to collect and analyze data to form the basis for CQE algorithms, methodologies and submodels and to verify the accuracy and integrity of the CQE software at the conclusion of the project. These responsibilities are described in Table 1-1.

At the conclusion of each testing program, the responsible contractor prepared a detailed report and data summary for the host utility to use in addressing near-term problems and objectives and to aid the other CQE project contractors in completing their assigned tasks.

Table 1-1
CQE Organizational Responsibility Assignment

Test Sites	ABB/CE and PSIT	B&W	B&V	CQ Inc.	UNDEERC	EPT	GUILD
Northeastern	5 DTFS 5 FPTF	NA	need FT/PT/BT data	2 CCC	4 DTFS 5 SEM	3 FT	NA
Watson	2 DTFS 2 FPTF	NA	need FT/PT/BT data	2 CCC	2 DTFS 2 SEM	2 FT	NA
King	NA	2 SBS	need FT/PT/BT data	5 CCC	2 SEM	2 FT	NA
Gaston	1 DTFS 1 FPTF	NA	need FT/PT/BT data	2 CCC	NA	2 FT	NA
Brayton Point	NA	NA	need FT data	NA	NA	2 FT	NA
Brayton Point	NA	NA	need FT data	NA	NA	2 FT	NA
Other CQE Work	commercial applications and slagging models	NA	CQE software developer, CQIM enhancements, ARA	Coal Cleaning Cost Model, CQIS enhancements, select CQE test sites	ash deposition data & fouling models	Fireside Testing Guidelines	develop CQE shell specs

CCC--Coal Cleanability Characterization
SBS--Small Boiler Simulator (Pilot Test)
BT--Bench Test
DTFS--Drop Tube Furnace System
FT--Field Test
PT--Pilot Test
FPTF--Fireside Performance Test Facility (Pilot Test)
SEM--Scanning Electron Microscopy

The highlights of the project are shown in Table 1-2.

The following U.S. electric utilities cofunded the project and participated in the field testing and software development/testing efforts.

Alabama Power Company
Wilsonville, AL

Duquesne Light Company
Pittsburgh, PA

Mississippi Power Company
Gulfport, MS

New England Power Company
Somerset, MA

Northern States Power
Oak Park, MN

Public Service Company of Oklahoma
Oologah, OK

Southern Company Services
Birmingham, AL

Table 1-2
Project Accomplishments

Accomplishment	Date
DOE awarded Cooperative Agreement	5/3/90
First of six field tests started	7/90
Pilot and bench-scale testing started	11/90
CQE specifications completed	2/15/92
Pilot and bench-scale testing completed	6/92
Acid Rain Advisor--first commercial product--released and copy sold	3/93
Completion of all six field tests	4/93
CQ Inc. and B&V signed CQE commercialization agreements	10/13/93
Conceptual design of the general Interactive Output Utility completed	8/94
Partially functional CQE beta version successfully tested	12/94
CQE alpha-version completed	3/31/95
CQE beta version completed and released for testing	6/95
Beta testing complete	11/30/95
CQE revised and issued on CD ROM	12/95
CQE Release 1.1 beta issued	6/7/96
Final Report	8/96
CQE Release 1.0	12/96

CQE builds on existing correlations from worldwide R&D on the impacts of coal quality for specific parts of the total power generation system. CQE features EPRI's CQIM as the calculational foundation for determining the impacts of different coals on plant performance and costs, and EPRI's Coal Quality Information System (CQIS™) provides a national database of coal quality information.

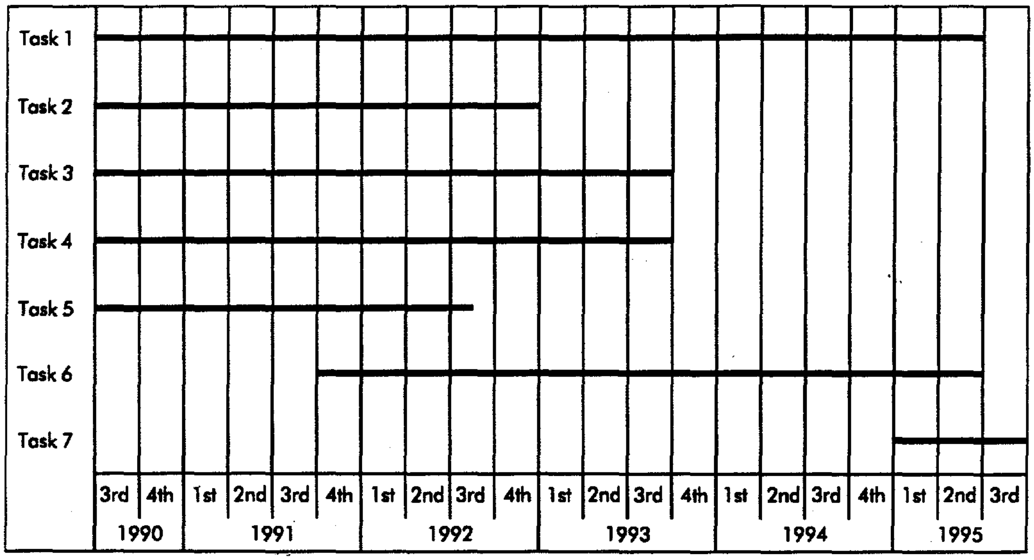
CQE combines the expertise from these established models--or the models themselves--into a single, personal computer-based tool. The electronic consultations that occur transparently between CQE's models let users address all aspects of fuel issues and their corresponding impacts on power generation systems.

This groundwork of established models is complemented by new and enhanced models derived from bench-, pilot-, and full scale test programs. These test programs, which allow coal-related effects to be distinguished from operational or design impacts, are among the most extensive of their kind ever conducted to relate power plant performance and emissions to coal quality.

Project Schedule

The original 42-month project actually spanned 64 months because the required "off-the-shelf" software for OS/2 was late.

The extended duration of the project required increased funding from EPRI and DOE, but it ensured that CQE was adequately planned and that CQE's underlying computer software was adequately proven. The project schedule is given in
Figure 1-2.



Task 1 - Project Management
Task 2 - Coal Cleanability Characterization
Task 3 - Pilot-Scale Combustion Testing
Task 4 - Utility Boiler Field Testing
Task 5 - CQIM Completion & Development of CQE Specifications
Task 6 - CQE Development
Task 7 - CQE Workstation Testing and Validation

Figure 1-2
Project Schedule

Objectives of the Project

The work falls under DOE's Clean Coal Technology Program category of "Advanced Coal Cleaning." The 64-month project provides the utility industry with a PC software program to confidently and inexpensively evaluate the potential for coal cleaning, blending, and switching options to reduce emissions while producing the lowest cost electricity. Specifically, this project was designed to:

- Enhance the existing Coal Quality Information System (CQIS) database and Coal Quality Impact Model (CQIM) to allow confident assessment of the effects of cleaning on specific boiler cost and performance.

- Develop and validate a methodology, Coal Quality Expert (CQE), which allows accurate and detailed predictions of coal quality impacts on total power plant operating cost and performance.

Significance of the Project

Originally, coal cleaning technologies were used only to remove ash-forming mineral matter. After passage of the 1970 Clean Air Act, coal cleaning processes were applied to a second purpose--sulfur reduction--accomplished primarily by removing the sulfur-bearing mineral pyrite. A great deal of geochemical information concerning the modes of occurrence of pyrite in coal was gathered and used to develop new methods of sulfur removal and to enhance existing methods. Today, coal cleaning plays a larger role in controlling SO_2 emissions than all post combustion control systems combined. It has led to reduced SO_2 emissions while U.S. coal use by utilities has increased steadily since 1970 (see Figures 1-3 and 1-4).

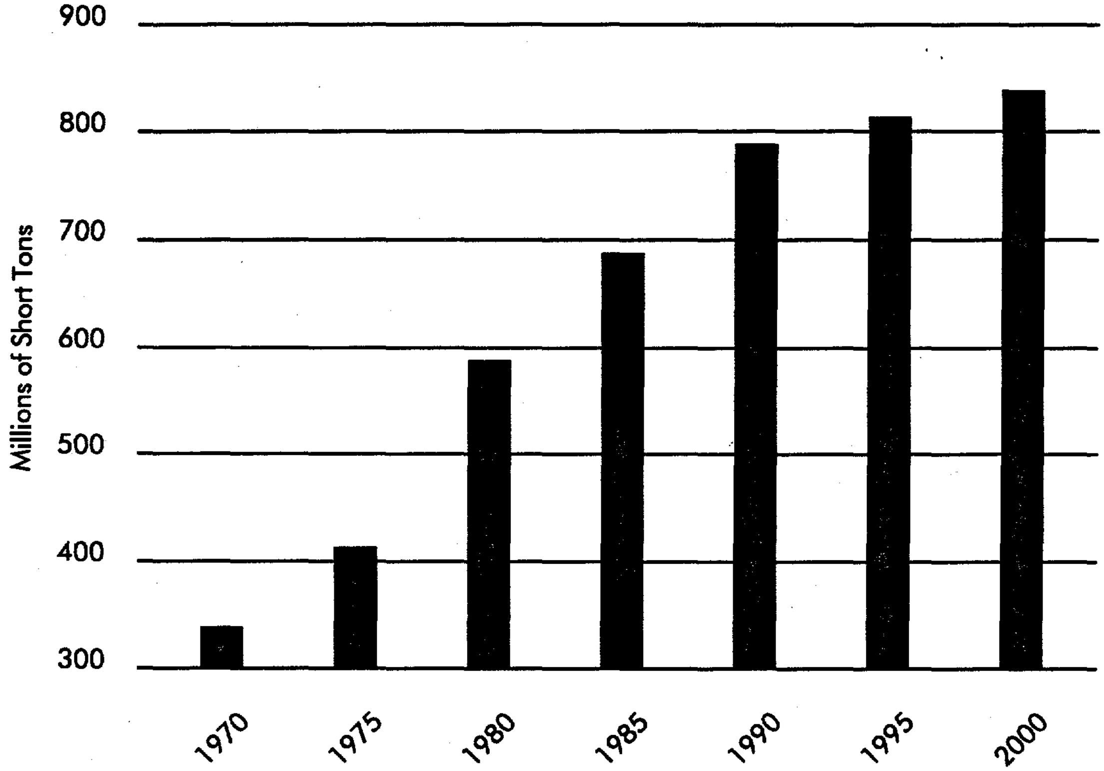


Figure 1-3
U.S. Utility Coal Use

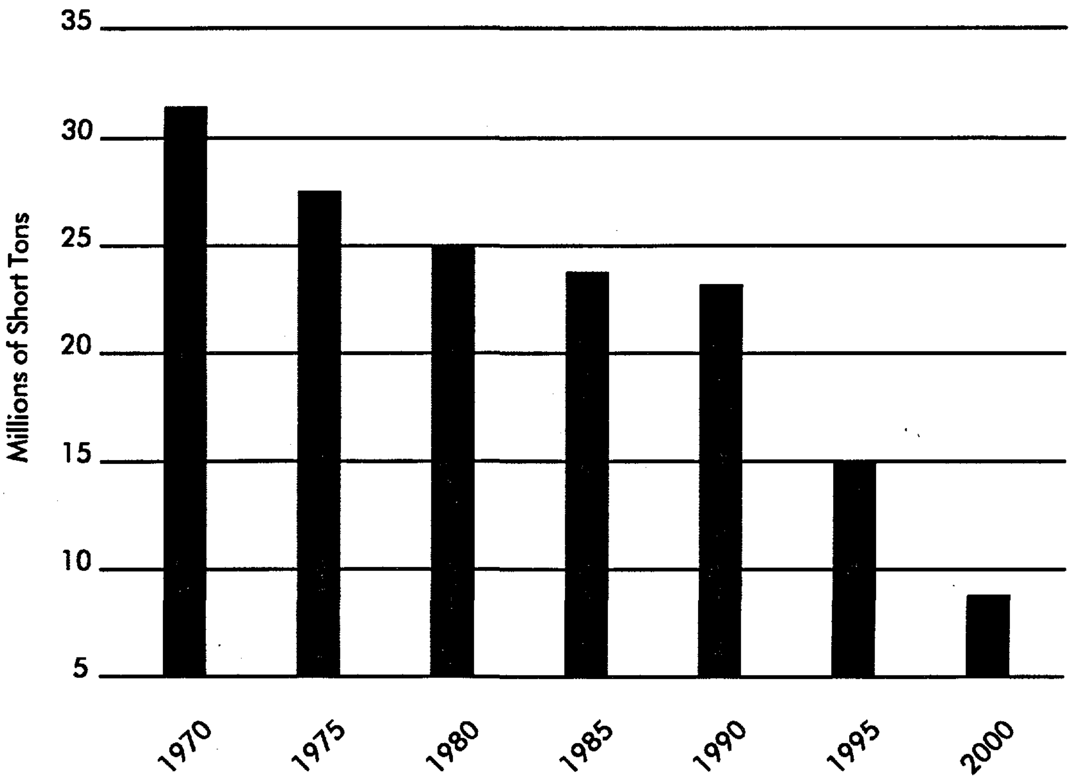


Figure 1-4
Total U.S. SO_2 Emissions

Coal cleaning has been commercially demonstrated as a means of reducing sulfur concentrations in some types of coal to levels which allow firing in boilers to conform to environmental standards without using scrubbers. In addition, coal cleaning reduces the concentrations of mineral impurities which may result in significant improvements in boiler performance, reduced maintenance, and increased availability. Figures 1-5 and 1-6 illustrate trade-offs which dictate the feasibility of coal cleaning. Sulfur emissions produced when burning a coal generally decrease with increased levels of cleaning. Fuel costs, however, increase with increased levels of cleaning (Figure 1-5). Another consideration is that performance benefits can increase with increased cleaning for existing units and higher quality fuel reduces new unit capital costs (Figure 1-6).

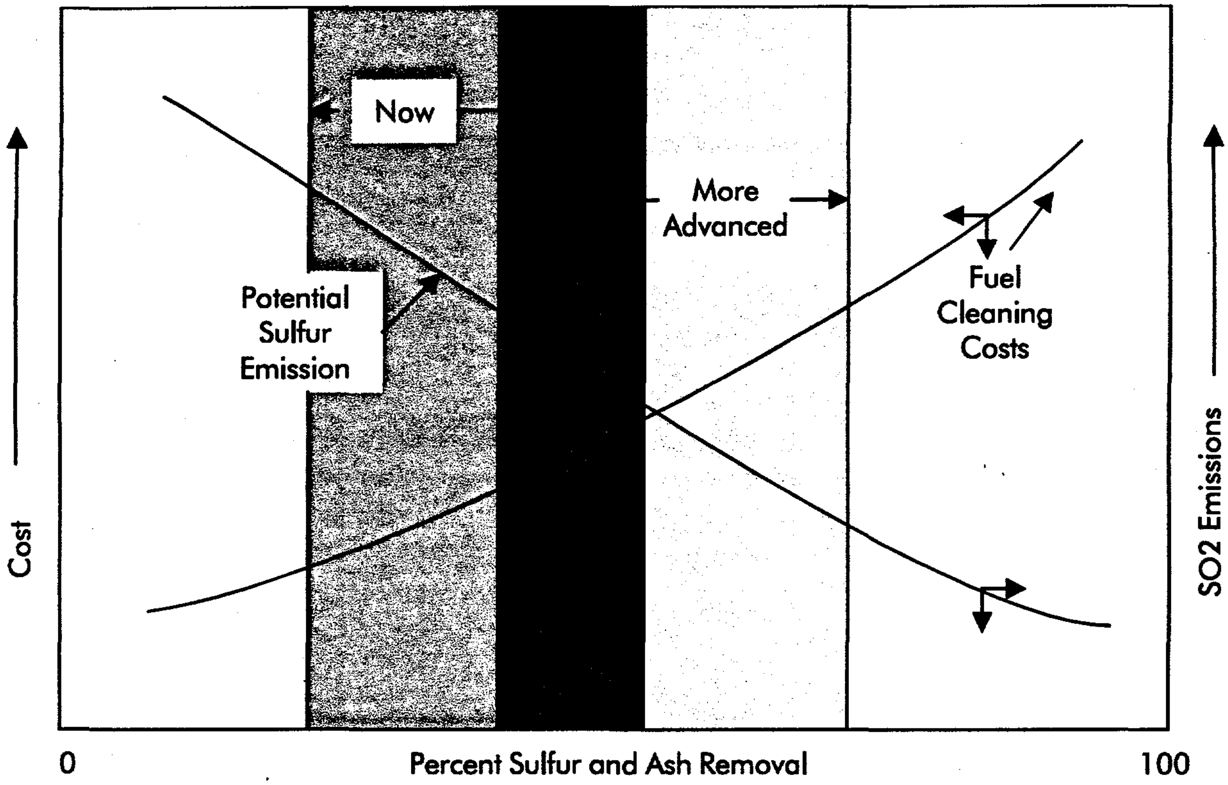


Figure 1-5
The Relationship Between Sulfur Emissions and Fuel Costs

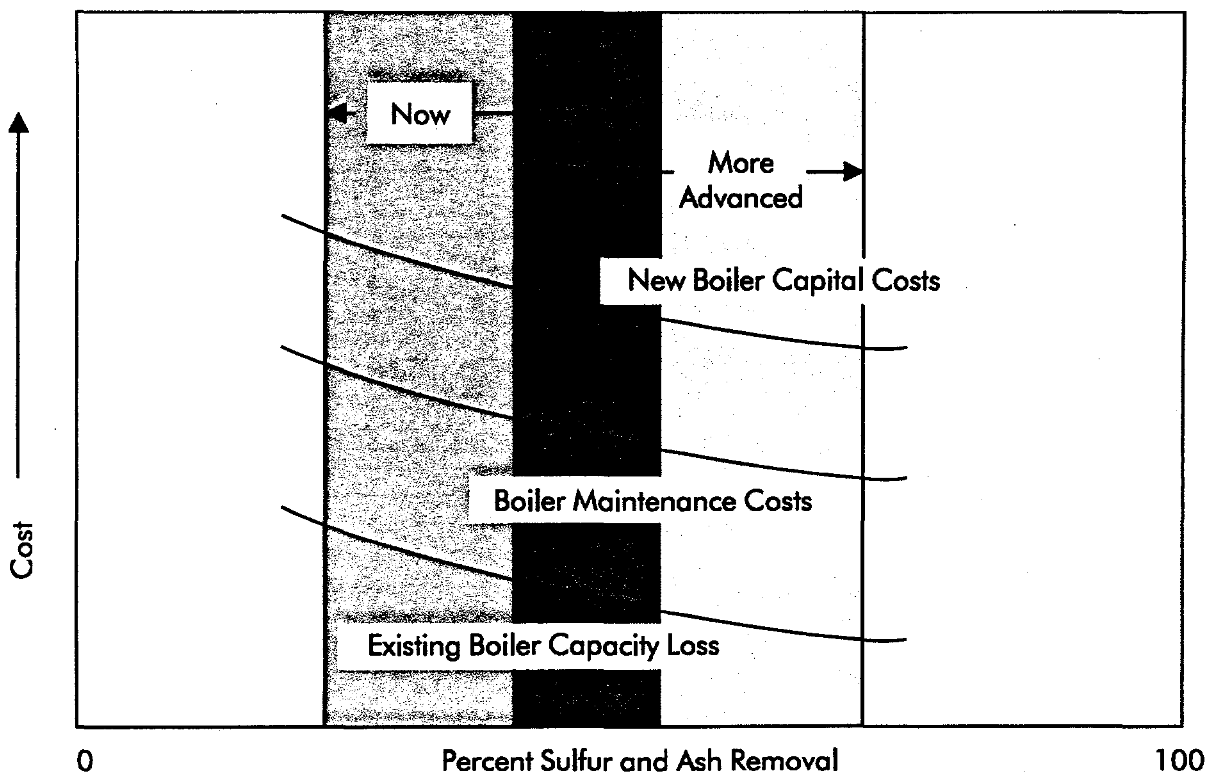


Figure 1-6

Coal Cleaning to Reduce Power Production Cost

Studies have indicated significant economic benefits due to coal cleaning (2). However, to accurately and completely assess the commercial viability of cleaning a particular coal, detailed large-scale combustion testing is necessary. Quantification of performance savings is necessary to compare the economic benefits obtainable through coal cleaning with the costs of other techniques for emission control. Industry currently does not have the capability to reliably predict the performance of cleaned coals without extensive studies. The relationship between level of confidence and testing coals is illustrated in Figure 1-7. Since many of today's bench-scale coal performance indices rely on empirical correlations, extrapolation of these indices to fuels not represented by the specific database used for correlation can be misleading. The need for quick, inexpensive tests that can be reliably used to assess the commercial impacts of coal cleaning is vital to implement clean coal technology. One of the major goals of the program was to develop and demonstrate simple techniques (bench-scale fuel properties and predictive models) to allow industry to confidently assess the overall impacts of coal quality and the economic implications during utilization.

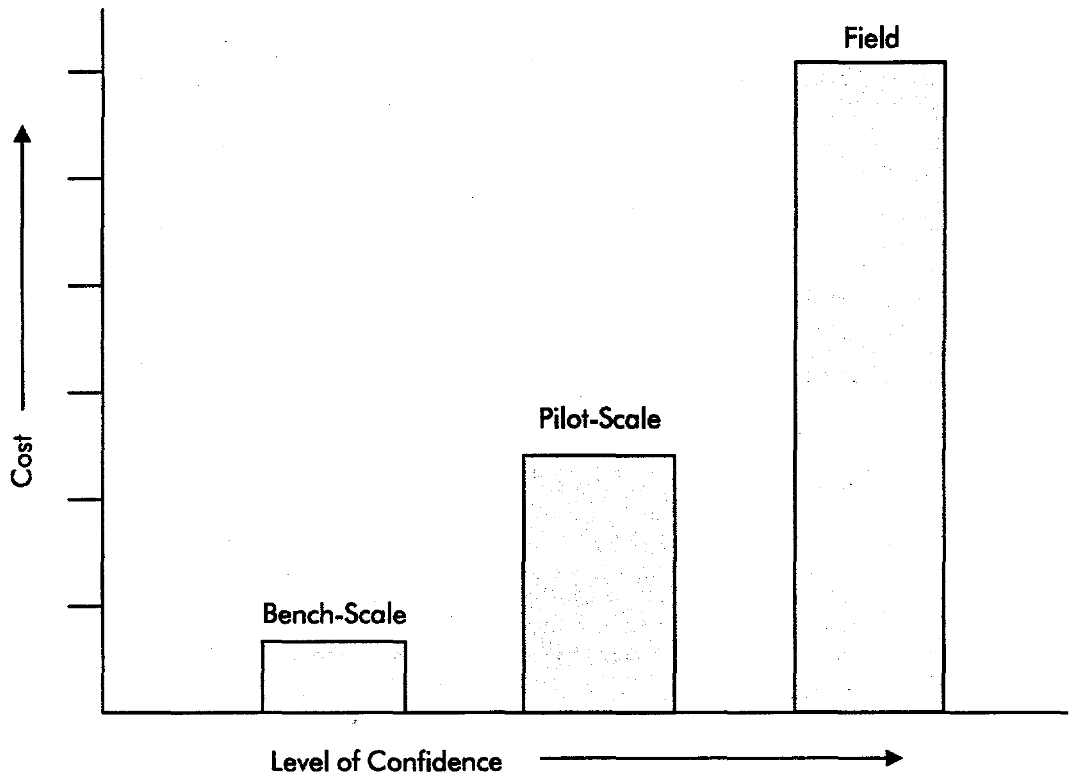


Figure 1-7
Relationship Between Testing Cost and Confidence Level of Commercial Predictions

The Significance of the CQE Tool

Fuel decisions affect nearly every aspect of power generation. Fuel buyers handle transportation issues and coal sourcing; plant engineers evaluate how individual coals behave in a unit; and environmental engineers address compliance and disposal issues. Typically, each expert uses an individual set of assumptions, data, and tools to complete an evaluation, resulting in one-dimensional pictures of fuel-related costs.

CQE integrates these assumptions, data, and tools, creating a unique electronic forum within which experts can efficiently and effectively share their knowledge and results.

The power of the forum is twofold. It not only centralizes all relevant information, it makes that information available to all other experts as appropriate. The end result of integrating a set of previously isolated analyses is a new capability that provides a complete picture of fuel-related impacts and costs.

One new capability, for instance, is CQE's ability to evaluate the economic tradeoffs between coal cleaning and scrubbing (Figure 1-8). Traditionally, utility engineers would combine results from two different models to compare the costs of cleaning and scrubbing. In contrast, a CQE analysis of cleaning versus scrubbing captures and consolidates the results of required analyses to determine the most cost-effective option or combination of options.

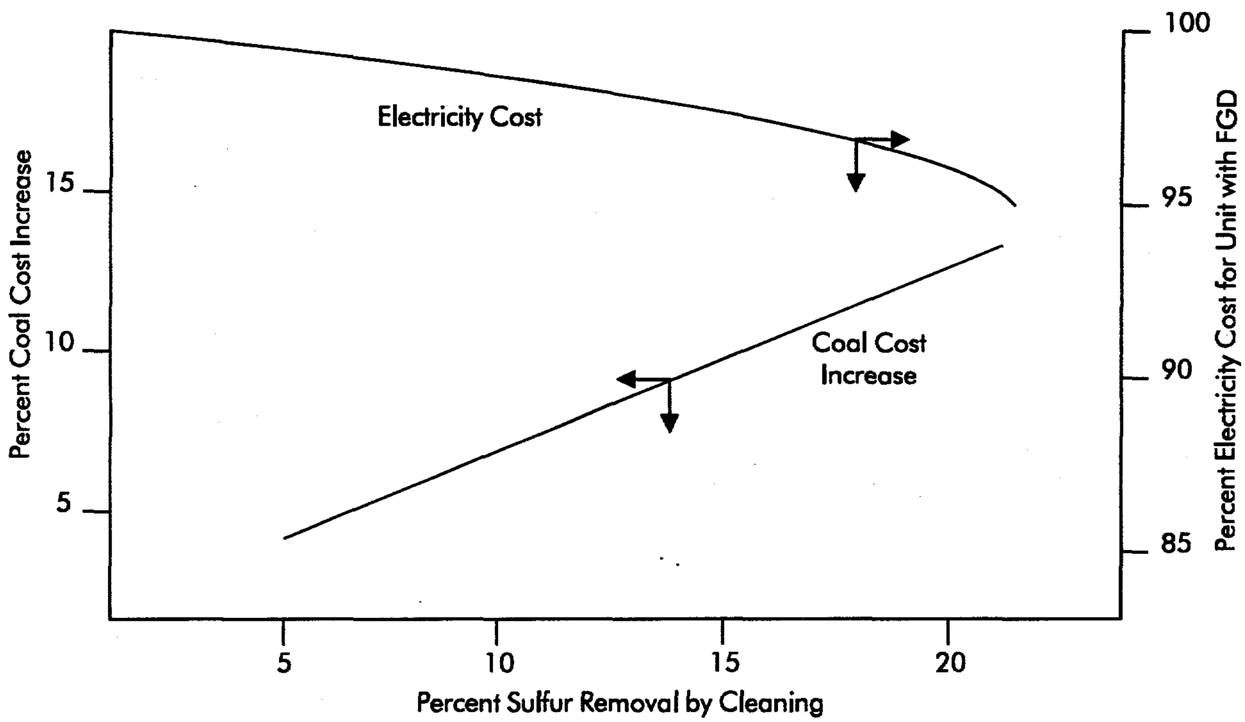


Figure 1-8
Economic Impact of Coal Cleaning

Commercial Potential and Plans

An analysis of the market for CQE shows that the most likely customers for CQE are power generation organizations, fuel suppliers, environmental organizations, government organizations, and engineering firms. These world-wide organizations can take advantage of CQE's ability to evaluate the impact of fuel quality on entire generating systems.

EPRI owns the software and distributes CQE to EPRI members for their use, and has contracted CQ Inc. as their commercialization agent. CQE is available to others in the form of three types of licenses: use, consultant, and commercialization. The largest market for use licenses with an introductory price of $90,000 is power generation organizations. Coal producers and equipment manufacturers are also prospective users. Large architect/engineering firms and boiler manufacturers are most likely to purchase consultant licenses or regional or world-wide commercialization licenses.

Black & Veatch executed the first CQE commercialization license with CQ Inc (as agent) and CQ Inc. is also licensed to commercialize CQE. Under the terms of that license, B&V and CQ Inc. are working collaboratively to sell use and consultant's licenses worldwide to provide consultation to organizations with coal quality projects and to continue the development of CQE software enhancements. Copies of CQE's stand-alone Acid Rain Advisor have been licensed to two U.S. users to date.

Conclusions and Recommendations

CQE will benefit owners and operators of coal-fired power plants in their commitments to produce energy economically and with concern for the environment. Utilities now have a tool to evaluate the system-wide consequences of fuel purchase decisions on power plant performance, emissions, and power generation costs. The software can examine potential changes in coal quality, transportation options, pulverizer performance, boiler slagging and fouling, emissions control alternatives and byproduct disposal for pulverized-coal and cyclone-fired power plants.

CQE will warrant further refinement and updating as new predictive models are validated. Future development of CQE should include coal gasification, fluidized bed boilers, European and Asian boiler design, and post combustion SO_2 and NO_x control technologies that are successfully demonstrated in U.S. Clean Coal Technology projects.

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SELF-SCRUBBING COAL - AN INTEGRATED APPROACH TO CLEAN AIR

K. E. Harrison, P.E.
Custom Coals Corporation
Pittsburgh, Pennsylvania

CONTENT

I. INTRODUCTION

On October 29, 1992, a Cooperative Agreement was executed by the United States Department of Energy (DOE) and Custom Coals Corporation (CCC). This agreement provides for the design, construction and operation of a coal preparation facility to produce Carefree Coal and Self-Scrubbing Coal, two fuels that will provide many United States utilities the opportunity to achieve compliance with the 1990 Clean Air Act Amendments (CAAA) without incurring major expenditures for power plant modifications.

Carefree Coal is coal cleaned in a proprietary dense-media cyclone circuit, using ultrafine magnetite slurries, to remove noncombustible material, including up to 90% of the pyritic sulfur. Deep cleaning alone, however, cannot produce a compliance fuel from coals with high organic sulfur contents. In these cases, Self-Scrubbing Coal will be produced. Self-Scrubbing Coal is produced in the same manner as Carefree Coal except that the finest fraction of product from the cleaning circuit is mixed with limestone-based additives and briquetted. The reduced ash content of the deeply-cleaned coal will permit the addition of relatively large amounts of sorbent without exceeding boiler ash specifications or overloading electrostatic precipitators. This additive reacts with sulfur dioxide (SO_2) during combustion of the coal to remove most of the remaining sulfur. Overall, sulfur reductions in the range of 80-90% are achieved.

After nearly 5 years of research and development of a proprietary coal cleaning technology coupled with pilot-scale validation studies of this technology and pilot-scale combustion testing of Self-Scrubbing Coal, CCC organized a team of experts to prepare a proposal in response to DOE's Round IV Program Opportunity Notice for its Clean Coal Technology Program under Public Law 101-121 and Public Law 101-512. The main objective of the demonstration project is the production of a coal fuel that will result in up to 90% reduction in sulfur emissions from coal-fired boilers at a cost competitive advantage over other technologies designed to accomplish the same sulfur emissions and over naturally occurring low sulfur coals.

II. PROJECT DESCRIPTION

The Demonstration Project, called the Laurel Facility, consists of a 500 TPH state-of-the-art, coal preparation plant and various product and raw coal handling and storage facilities. During the current project operations phase, the advanced coal cleaning cyclone and various ancillary magnetite recovery schemes are being demonstrated as well as the demonstration of combustion of the Carefree Coal and Self-Scrubbing Coal at full size power plant boilers.

Goals

CCC's goal for the project is to successfully commercialize its first plant and use that success to build a merchant coal preparation business. DOE's goal is to ensure the long term availability of a low cost, environmentally friendly fuel for our nation's long term energy needs.

Participants

The Project Team assembled to carry out the demonstration project includes:

- DOE's Project Management Team from PETC
- Custom Coals Corporation (CCC), overall project manager and lessee of patents for the technology
- Affiliated Engineering Technologies, Inc., design contractor
- Riggs Industries, Construction Managers
- Richmond Power & Light, utility host site
- Centerior Energy, utility host site
- Pennsylvania Power & Light, utility host site

III. PROJECT STATUS

- Design and construction of the facilities was completed in early 1996. Start-up began in late December 1995 and the first coal was processed on February 22, 1996. The plant circuits were fed an increasing amount of throughput and various adjustments to water and media flows were made until, in May of 1996, the facility reached its design capacity. Equipment and circuit optimization testing began immediately thereafter and have continued throughout the remainder of the year.

- One of the test burns, the Carefree Coal test at Pennsylvania Power and Light's Martins Creek Station, was conducted in mid-November. Although several of the plant circuits were performing below the expected proficiency because optimization has not been completed, the overall plant product produced for the test was consistent with the current quality of the plant feed coal.

- The later sections will detail the Start-up, the Circuit Optimization and the Equipment Performance work completed to date and provide the team's plans for completing the demonstration program.

- The project, as approved through Budget Period 3, calls for a total cost of \$87,386,102, with DOE providing \$37,994,437 or 43.5% of the funds. The project is expected to be completed in June 1997.

ROSEBUD SYNCOAL PARTNERSHIP SYNCOAL® DEMONSTRATION TECHNOLOGY UPDATE

Ray W. Sheldon, P.E.
Rosebud SynCoal Partnership
Billings, Montana

Fifth Annual Clean Coal Technology Conference
January 7-10, 1997
Tampa, Florida

SYNCOAL® PROCESS IMPROVES LOW-RANK COALS

An Advanced Coal Conversion Process (ACCP) technology being demonstrated in eastern Montana (USA) at the heart of one of the world's largest coal deposits is providing evidence that the molecular structure of low-rank coals can be altered successfully to produce a unique product for a variety of utility and industrial applications.

The product is called SynCoal® and the process has been developed by the Rosebud SynCoal Partnership (RSCP) through the U.S. Department of Energy's multi-million dollar Clean Coal Technology Program. RSCP is a Colorado (USA) general partnership formed for the purpose of conducting the Clean Coal Technology Program demonstration and the commercializing of the ACCP technology.

Western SynCoal Company, a subsidiary of Montana Power Company's Energy Supply Division, is the managing general partner of RSCP. The other general partner is Scoria Inc. a subsidiary of NRG Energy, the nonutility entity of Northern States Power Company of Minnesota (USA).

Montana Power Company's subsidiary, Western Energy Company, initially developed the ACCP technology and signed the original Cooperative Agreement with the Department of Energy (DOE) to build the demonstration facility under the Clean Coal Technology Program (CCT I). Western Energy then formed Western SynCoal Company and joined with Scoria. RSCP's partners own the technology in undivided interests and have exclusively licensed it to the partnership. The RSCP partnership manages the $105 million demonstration project adjacent to the Rosebud Mine at Colstrip, Montana and all activities related to technology commercialization. **(See Demo Plant Location Map)** DOE has committed $43.125 million in funding to the demonstration project. Rosebud SynCoal is responsible for all additional funding and operation of the project.

The patented ACCP process improves the heating quality of low rank coals to produce an upgraded coal produced called SynCoal®, which is a registered trademark owned by RSCP.

Process

The ACCP demonstration process uses low-pressure, superheated gases to process coal in vibrating fluidized beds. Two vibratory fluidized processing stages are used to heat and convert the coal. This is followed by a water spray quench and a vibratory fluidized stage to cool the coal. Pneumatic separators remove the solid impurities from the dried coal.

There are three major steps to the SynCoal® process: (1) thermal treatment of the coal in an inert atmosphere, (2) inert gas cooling of the hot coal, and (3) removal of ash minerals. **See Flow Diagram**

(1) During the thermal treatment process, raw coal from the stockpile is screened and fed into a two-stage thermal processing system. In the first vibratory fluidized-bed reactor, surface water is removed from the coal by heating it with hot combustion gas. When the coal exits this reactor, its temperature is slightly higher than that required to evaporate water. The coal is further heated to nearly 300° C (5° F) in a second reactor to a temperature sufficient to remove pore water and prompting decarboxylation. Here, particle shrinkage causes fracturing, destroys moisture reaction sites, and separates out the coal ash minerals.

(2) The coal then enters the coal cooler, where it is cooled to less than 150°F by contact with an inert gas (carbon dioxide and nitrogen at less than 100°F) in a vibrating fluidized bed cooler.

(3) In the last stage -- the coal cleaning system -- cooled coal is fed to deep bed stratifiers where air velocity and vibration separate mineral matter from the coal with rough gravity separation. The low specific gravity fractions are sent to a product conveyor while heavier specific gravity fractions go to fluidized bed separators, for additional ash removal. Fines from various parts of the cleaning process are collected in baghouses and cyclones, cooled and made available as an additional product line.

The SynCoal® is a high quality product with less than 5 percent moisture, sulfur content of 0.5 percent, ash content of about 9 percent, and a heating value of about 11,800 Btu per pound.

When operated continuously, the demonstration plant produces over 1,000 tons per day (up to 300,000 tons per year) of SynCoal® with a 2% moisture content, approximately 11,800 Btu/lb and less than 1.0 pound of SO_2 per million Btu . This product is obtained from Rosebud Mine sub-bituminous coal which starts with 25% moisture, 8,600 Btu/lb and approximately 1.6 pounds of SO_2 per million Btu.

Nearly 1.3 million tons of raw coal has been processed and over 850,000 tons of SynCoal® has been produced through October 1996. The plant has consistently operated at over 100% of design capacity and over 75% availability. **See SynCoal Production and Sales History and Monthly Operating Statistics**

Utility Applications - Customer Results

A SynCoal® test-burn was completed at the 160 MW. J.E. Corette plant in Billings, Montana. A total of 204,478 tons of SynCoal® was burned between mid 1992 and April, 1996. The testing involved both handling and combustion of SynCoal® in a variety of blends. These blends ranged from approximately 15% SynCoal® to approximately 85% SynCoal®. Overall the results indicated that a 50% DSE SynCoal®/raw coal blend provided improved results with SO_2 emissions reduced by 21% overall, generation increased at normal operating loads and no noticeable impact on NOx emissions. DSE is a treatment to improve SynCoal®'s bulk handling characteristics when using conventional handling techniques. It controls dusting of the product and provides temporary resistance to spontaneous combustion.

Additionally SynCoal® deslagged the boiler at full load eliminating costly ash shedding operations and provided reduced gas flow resistance in the boiler and convection passage, reducing fan horsepower and improving heat transfer in the boiler area, resulting in increased generation by approximately 3 megawatts on a net basis.

Deliveries of SynCoal® are now being sent to Colstrip Project Units 1 & 2 in Colstrip, Montana. Testing has begun on the use of SynCoal® in these twin 320-megawatt pulverized coal fired plants. The results of these tests will provide information on: boiler efficiency, output, and air emissions. A total of 61,339 tons have been consumed to date.

A new SynCoal® delivery system is being designed which, if installed, would provide selectively controlled pneumatic delivery of SynCoal® to pulverizers individual pulverizers in the two units. This system would allow controlled tests in the two units providing valuable test data on emissions, performance and slagging. The use of both units operating at similar loads and with the same raw coal would provide a unique opportunity to perform directly comparative testing.

In May 1993, 190 tons of Center, North Dakota lignite was processed at the ACCP demonstration facility in Colstrip, producing 10,740 Btu/lb product and 47% reduction in sulfur and a 7% percent reduction in ash. In September 1993, a second test was performed processing 532 tons of lignite, producing a 10,567 Btu/lb product with a 48% sulfur reduction and a 27% ash reduction. The Center lignite before beneficiation had 36% moisture, approximately 6,800 Btu/lb at about 3.0 lbs of SO_2 per million Btu.

Approximately 190 tons of these upgraded products produced in September was returned two days later to the Milton R. Young Unit #1 and burned in an initial test showing dramatic improvement in cyclone combustion, improved slag tapping and a 13%

reduction in boiler air flow, reducing the auxiliary power loads on the forced draft and induced draft fans. Additionally the boiler efficiency increased from 82% to in excess of 86% and the total gross heat rate improved by 123 Btu/kWh hour.

The operation of the cyclone units at the Milton R. Young facility are plagued by cyclone barrel slagging which is typically removed by burning additional No. 2 fuel oil. These units also slag and foul in the boiler and convective passes requiring complete shutdown and cold boiler washing between three and four times a year.

In an effort to reduce these detrimental effects, Minnkota Power has tested the use of SynCoal® as a substitute for fuel oil when removing cyclone slag and also as a steady additive to reduce the boiler slagging and convective fouling to reduce the number of cold boiler washings necessary. The fuel oil substitute testing nicknamed "Klinker Killer" has been successfully tested showing the SynCoal® is at least as effective in removing cyclone barrel clinkers on a Btu for Btu basis as fuel oil. The SynCoal® produces a much higher temperature in the cyclone barrel than lignite increasing the cyclone barrel front wall temperature as much as 900° F and more closely matched the design temperature profile which improves the cyclone combustion operation dramatically.

The testing to support the long term objective has indicated that SynCoal® would be effective in this application although the limited duration of these tests has left them less than fully conclusive.

Industry Applications - Customer Results

Several industrial cement and lime plants have been customers of SynCoal® for an extended period of time. A total of 129,056 tons have been delivered to these customers from 1993 through October 1996. In their testing and use of SynCoal® they have found that it improves their production from their direct fired kiln applications. These improvements are both in capacity and product quality as the steady flame produced by SynCoal® appears to allow tighter process control and process optimization in their operations.

A bentonite producer has been using SynCoal® as an additive in their green sand molding product for use in the foundry industry. The bentonite company has used SynCoal® since 1993 and has taken approximately 30,569 tons. SynCoal® has been found to be a very consistent product allowing their customers to reduce the quantity of additives used and improving the quality of the metal casting produced.

Commercialization

Western SynCoal Company has moved closer to building a $37.5 million commercial SynCoal plant at Minnkota's Milton R. Young Power Station near Center, North Dakota.

Minnkota is a generation and transmission cooperative supplying wholesale electricity to 12 rural electric cooperatives in eastern North Dakota and northwestern Minnesota.

Minnkota owns and operates the 250-megawatt Unit 1 at the Young Station, and operates the 438-mw Unit 2 which is owned by Square Butte Electric Cooperative of Grand Forks. This power station is already one of the lowest cost electric generating plants in the nation; however, with the use of SynCoal® the operations of the plant could further improve.

The SynCoal plant would produce an estimated 403,000 tons of finished product annually, which would be blended with the lignite. The reduced slagging and fouling improves generating plant maintenance and allows potentially longer runs between downtimes to ultimately produce more electricity. The process is anticipated to boost the lignite heating value by 60 percent and could lower its sulfur content by 50 percent with an anticipated second phase of the project.

International

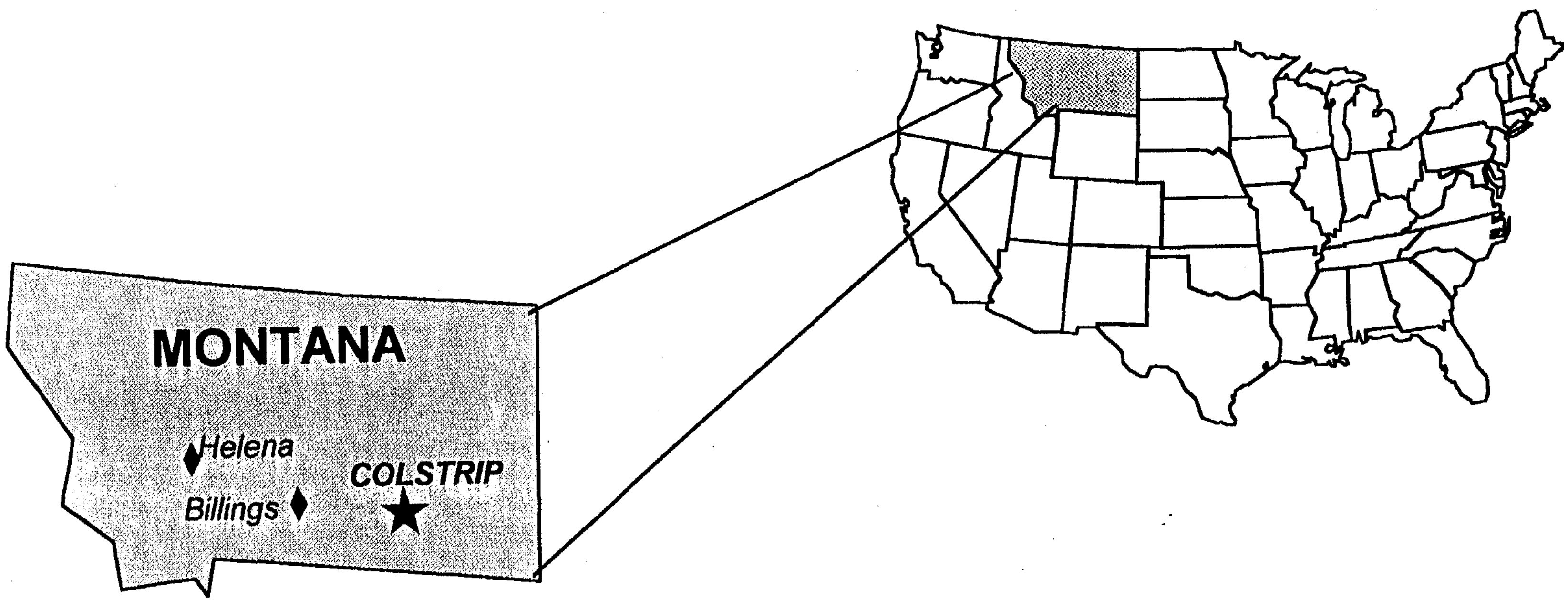
RSCP has been actively marketing and promoting the SynCoal® technology world-wide. RSCP has been working closely with a Japanese equipment and technology company to expand into Asian markets. Prospects are also being pursued in Europe currently.

Summary

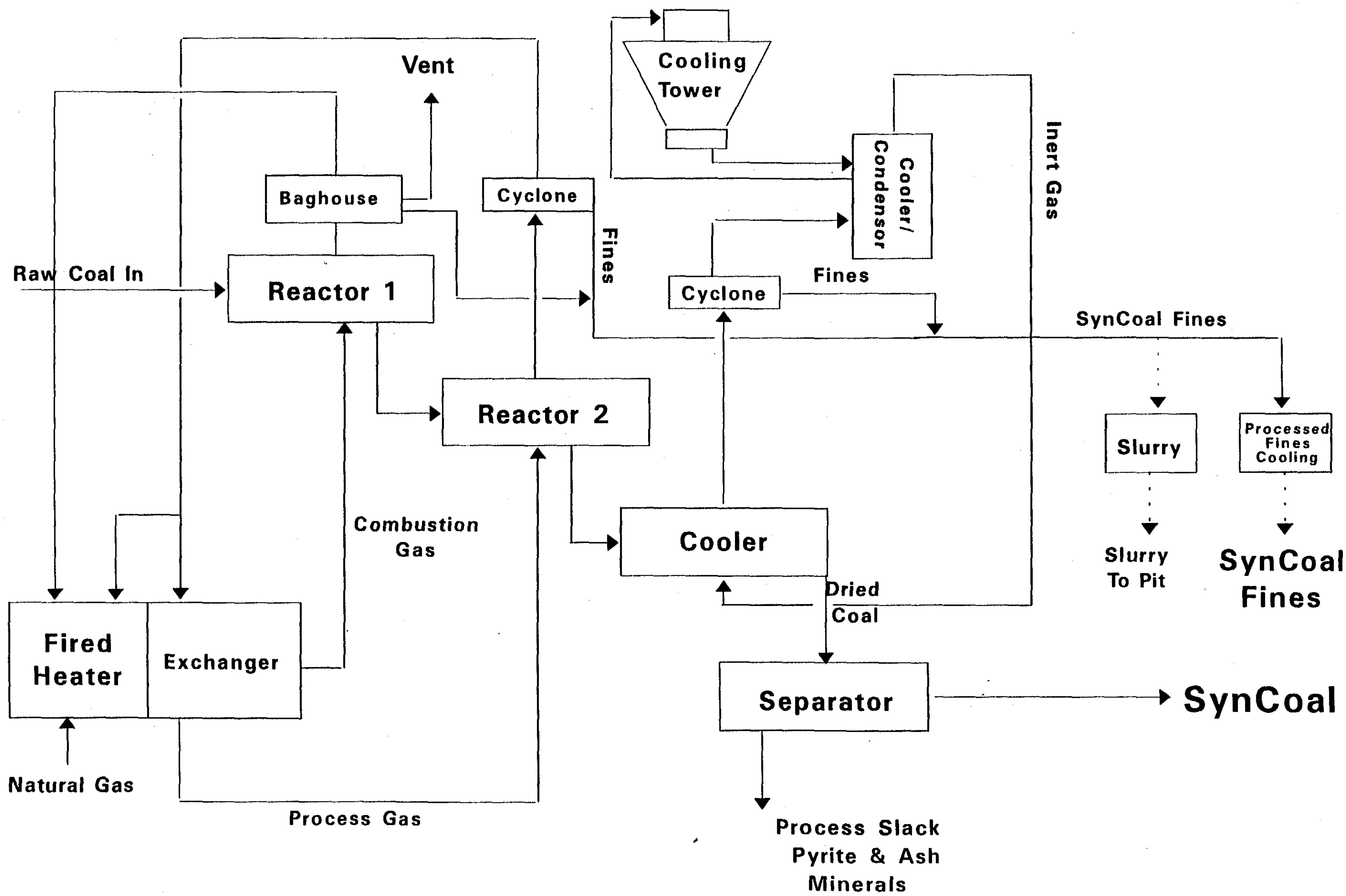
Rosebud SynCoal is continuing to advance the SynCoal® technology in a prudent and organized manner. The work to date has made SynCoal® the most advanced Low Rank Coal upgrading technology available and has put it on the cusp of commercial viability. The successful conclusion of the Center SynCoal Project and the enhanced SynCoal® delivery system and testing in Colstrip will position SynCoal® to be a viable option to enhance low rank coal fired utility operations.

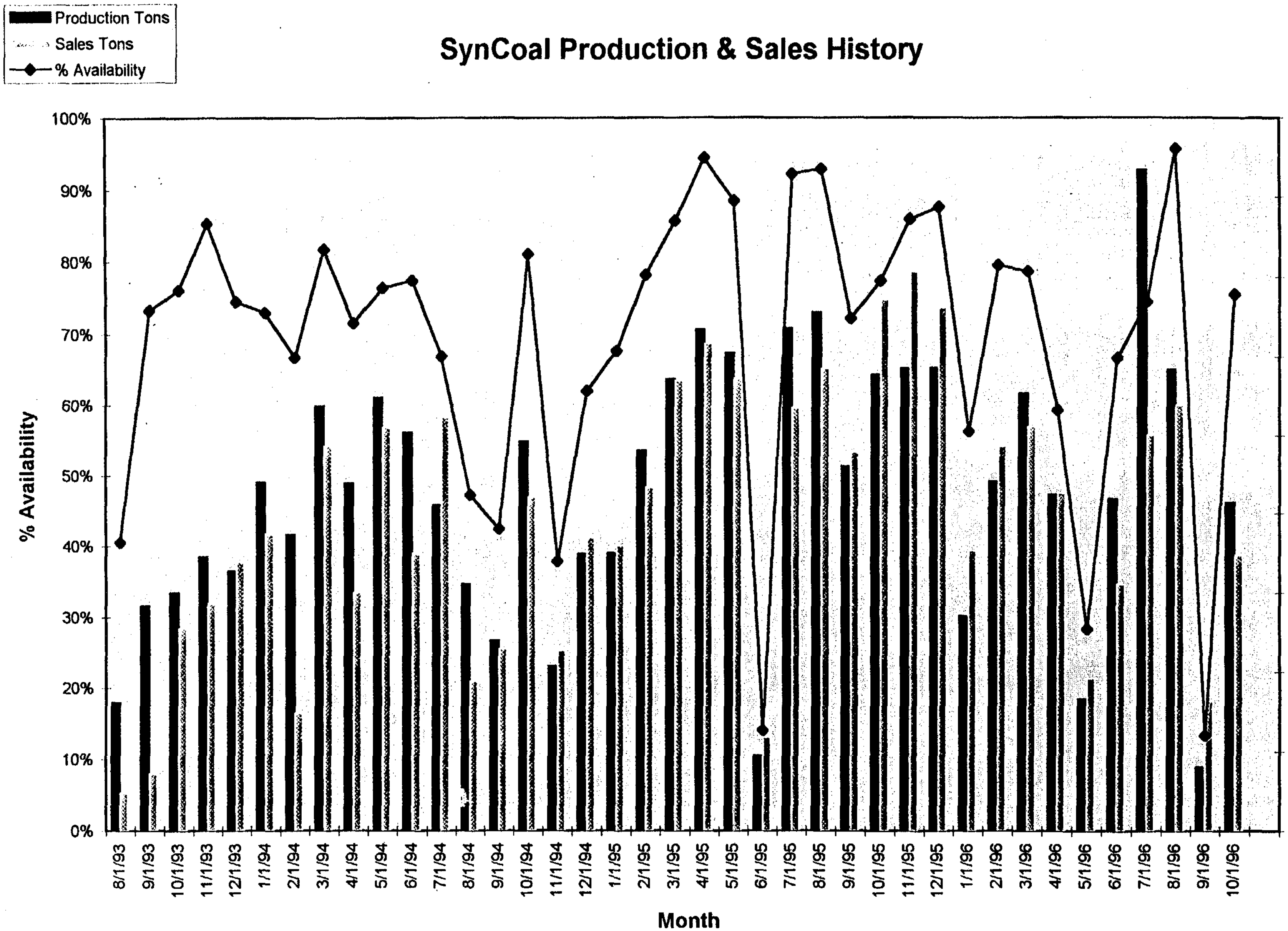
ADVANCED COAL CONVERSION PROCESS

Demo Plant Location



Process Flow Diagram




Production Tons
Sales Tons
% Availability
SynCoal Production & Sales History
% Availability
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90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
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8/1/93
9/1/93
10/1/93
11/1/93
12/1/93
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4/1/96
5/1/96
6/1/96
7/1/96
8/1/96
9/1/96
10/1/96
Month

ACCP MONTHLY OPERATING STATISTICS

MONTH	PRODUCTION AVAILABILITY	FORCED OUTAGE RATE	TONS PROCESSED	CAPACITY FACTOR	SHIPMENTS
Mar-92	4%	96%	700	2%	181
Apr-92	7%	89%	411	1%	212
May-92	12%	76%	2,757	7%	0
Jun-92	13%	81%	2,496	7%	214
Jul-92	7%	56%	1,436	4%	0
Aug-92	17%	60%	1,860	5%	61
Sep-92	44%	33%	8,725	24%	1,672
Oct-92	13%	63%	2,292	6%	523
Nov-92	58%	28%	6,946	19%	2,386
Dec-92	11%	80%	1,063	3%	317
Jan-93	53%	26%	8,626	23%	3,658
Feb-93	44%	18%	6,544	19%	915
Mar-93	44%	34%	6,565	17%	629
Apr-93	49%	30%	8,514	23%	745
May-93	47%	39%	9,256	24%	768
Jun-93	15%	26%	2,752	7%	199
Jul-93	0%		0	0%	655
Aug-93	41%	43%	13,427	35%	2,361
Sep-93	73%	18%	23,276	63%	3,528
Oct-93	76%	11%	24,606	64%	12,753
Nov-93	85%	14%	27,927	76%	14,349
Dec-93	74%	9%	26,009	68%	16,951
Jan-94	73%	17%	34,979	92%	19,093
Feb-94	67%	28%	29,247	85%	7,909
Mar-94	82%	14%	41,891	110%	24,627
Apr-94	72%	27%	33,686	91%	15,622
May-94	76%	8%	39,404	103%	26,415
Jun-94	77%	23%	36,657	99%	18,873
Jul-94	67%	33%	34,026	89%	26,527
Aug-94	47%	19%	24,645	64%	9,146
Sep-94	42%	35%	20,327	55%	11,408
Oct-94	81%	16%	34,908	91%	19,161
Nov-94	38%	62%	16,418	44%	11,169
Dec-94	62%	27%	25,258	66%	18,478
Jan-95	68%	32%	31,726	83%	17,695
Feb-95	78%	22%	38,325	111%	21,710
Mar-95	86%	4%	42,674	112%	28,548
Apr-95	94%	1%	47,818	129%	30,827

MONTH	PRODUCTION AVAILABILITY	FORCED OUTAGE RATE	TONS PROCESSED	CAPACITY FACTOR	SHIPMENTS
May-95	88%	5%	43,752	114%	28,674
Jun-95	14%	26%	7,142	19%	5,859
Jul-95	92%	8%	48,512	127%	26,795
Aug-95	93%	4%	48,889	128%	29,261
Sep-95	72%	28%	37,129	100%	23,954
Oct-95	77%	10%	43,316	113%	33,614
Nov-95	86%	14%	42,807	116%	35,380
Dec-95	88%	13%	47,531	124%	33,101
Jan-96	56%	44%	24,710	65%	17,662
Feb-96	79%	21%	36,280	101%	24,340
Mar-96	79%	21%	39,071	104%	25,566
Apr-96	59%	19%	30,038	81%	21,321
May-96	28%	11%	13,282	35%	9,571
Jun-96	67%	21%	31,775	85%	15,553
Jul-96	74%	26%	35,056	92%	24,998
Aug-96	96%	4%	43,832	117%	29,200
Sept-96	13%	33%	6,117	16%	8,112
Oct-96	75%	25%	33,730	90%	17,375
	TOTAL		1,331,146		780,621

Technical Session II
Advanced Industrial Systems

AN UPDATE ON BLAST FURNACE GRANULAR COAL INJECTION

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ABSTRACT

A blast furnace coal injection system has been constructed and is being used on the furnaces at the Burns Harbor Division of Bethlehem Steel. The injection system was designed to deliver both granular (coarse) and pulverized (fine) coal. Construction was completed on schedule in early 1995. Coal injection rates on the two Burns Harbor furnaces were increased throughout 1995 and was over 200 lbs/ton on C furnace in September. The injection rate on C furnace reached 270 lbs/ton by mid-1996. A comparison of high volatile and low volatile coals as injectants shows that low volatile coal replaces more coke and results in a better blast furnace operation. The replacement ratio with low volatile coal is 0.96 lbs coke per pound of coal. A major conclusion of the work to date is that granular coal injection performs very well in large blast furnaces. Future testing will include a processed sub-bituminous coal, a high ash coal and a direct comparison of granular versus pulverized coal injection.

I. INTRODUCTION

A blast furnace coal injection system has been installed at the Burns Harbor Division of Bethlehem Steel Corporation. This is the first blast furnace coal injection system in the US that has been designed to deliver granular (coarse) coal - all previously installed blast furnace coal injection systems in the US have been designed to deliver pulverized (fine) coal. Financial assistance for the coal injection system was provided by the Clean Coal Technology Program.

The use of granular coal in blast furnaces was jointly developed by British Steel and Simon-Macawber (now CPC-Macawber) and used at the Scunthorpe Works in England. The blast furnaces at Scunthorpe have about one-half the production capability of the Burns Harbor blast furnaces. Therefore, one of the main objectives of the Clean Coal Technology (CCT) test program at Burns Harbor is to determine the effect of granular coal injection on large high productivity blast furnaces. Another objective of the CCT test program at Burns Harbor is to determine the effect of different types of US coals on blast furnace performance.

The Burns Harbor Plant produces flat rolled steel products for the automotive, machinery and construction markets. The Plant is located on the southern shore of Lake Michigan about 30 miles east of Chicago. Burns Harbor is an integrated operation that includes two coke oven batteries, an iron ore sintering plant, two blast furnaces, a three vessel BOF shop and two twin-strand slab casting machines. These primary facilities can produce over five million tons of raw steel per year. The steel finishing facilities at Burns Harbor include a hot strip mill, two plate mills, a cold tandem mill complex and a hot dip coating line.

When originally designed and laid-out, the Burns Harbor Plant could produce all the coke required for the two blast furnaces operating at 10,000 tons/day. However, improved practices and raw materials have resulted in a blast furnace operation that now can produce over 14,000 tons/day. Since the coke oven batteries are not able to produce the coke required for a 14,000 ton/day blast furnace output, other sources of coke and energy have been used to fill the gap. Over the years, coke has been shipped to Burns Harbor from other Bethlehem plants and from outside coke suppliers. In addition, auxiliary fuels have been injected into the furnaces to reduce the coke requirements. The auxiliary fuels have included coal tar, fuel oil and natural gas. The most successful auxiliary fuel through the 1980s and early 1990s has been natural gas. It is easy to inject and, at moderate injection levels, has a highly beneficial effect on blast furnace operations and performance. However, there are two significant problems with the use of natural gas in blast furnaces. One problem is the cost and the other is the amount that can be injected and, therefore, the amount of coke that can be replaced. Our process and economic studies showed that more coke could be replaced and iron costs could be reduced by injecting coal instead of natural gas in the Burns Harbor furnaces.

This led Bethlehem to submit a proposal to the DOE to conduct a comprehensive assessment of coal injection at Burns Harbor. Following an extensive review by the DOE, Bethlehem's Blast Furnace Granular Coal Injection System Demonstration Project was one of thirteen demonstration projects accepted for funding in the Clean Coal Technology Program third round of competition. The primary thrust of the project is to demonstrate commercial performance characteristics of granular coal as a supplemental fuel for steel industry blast furnaces. The technology will be demonstrated on large high productivity blast furnaces using a wide range of coal types available in the US. The planned tests will assess the impact of coal particle size distribution as well as chemistry on the amount of coal that can be injected effectively. Upon successful completion of the work, the results will provide the information and confidence needed by others to assess the technical and economic advantages of applying the technology to their own facilities.

A major consideration in evaluating coal injection in the US is the aging capacity of existing cokemaking facilities and the high capital cost to rebuild these facilities to meet emission guidelines under the Clean Air Act Amendments. The increasingly stringent environmental regulations and the continuing decline in domestic cokemaking capability will cause significant reductions in the availability of commercial coke over the coming years. Due to this decline in availability and increase in operating and maintenance costs for domestic cokemaking facilities, commercial coke prices are projected to increase by more than general inflation. Higher levels of blast furnace injectants, such as coal, enable domestic integrated steel producers to minimize their dependence on coke.

Blast Furnace Process

The ironmaking blast furnace is at the heart of integrated steelmaking operations. As shown in Figure 1, the raw materials are charged to the top of the furnace through a lock hopper arrangement to prevent the escape of pressurized hot reducing gases. Air needed for the combustion of coke to generate the heat and reducing gases for the process is passed through stoves and heated to 1500-2300°F. The heated air (hot blast) is conveyed to a refractory-lined bustle pipe located around the perimeter of the furnace. The hot blast then enters the furnace through a series of ports (tuyeres) around and near the base of the furnace. The molten iron and slag are discharged through openings (tapholes) located below the tuyeres. The molten iron flows to refractory-lined ladles for transport to the basic oxygen furnaces.

A schematic showing the various zones inside the blast furnace is shown in Figure 2. As can be seen, the raw materials, which are charged to the furnace in batches, create discrete layers of ore and coke. As the hot blast reacts with and consumes coke at the tuyere zone, the burden descends in the furnace resulting in a molten pool of iron flowing around unburned coke just above the furnace bottom (bosh area). Reduction of the descending ore occurs by reaction with the rising hot reducing gas that is formed when coke is burned at the tuyeres.

The cohesive zone directly above the tuyeres is so called because it is in this area that the partially reduced ore is being melted and passes through layers of coke. The coke layers provide the permeability needed for the hot gases to pass through this zone to the upper portion of the furnace. Unlike coal, coke has the high temperature properties needed to retain its integrity in this region and is the reason that blast furnaces cannot be operated without coke in the burden.

The hot gas leaving the top of the furnace is cooled and cleaned. Since it has a significant heating value (80-100 Btu/scf), it is used to fire the hot blast stoves. The excess is used to generate steam and power for other uses within the plant.

II. COAL INJECTION TECHNOLOGY

Bethlehem decided to utilize the CPC Macawber Blast Furnace Granular Coal Injection (BFGCI) System, because unlike more widely used systems that utilize only pulverized coal, it is capable of injecting both granular and pulverized coal. Bethlehem believes that the CPC Macawber system offers a variety of technical and economic advantages which make this system potentially very attractive for application in the US basic steel industry. A schematic showing the application of the technology to the blast furnace is shown in Figure 3. Some of the advantages of this technology include:

- The injection system has been used with granular coal as well as with pulverized coal. No other system has been utilized over this range of coal sizes. Granular coal is 10-30% minus 200 mesh whereas pulverized coal is 70-80% minus 200 mesh.

- The costs for granular coal preparation systems are less than those for the same capacity pulverized coal systems.

- Granular coal is easier to handle in pneumatic conveying systems. Granular coals are not as likely to stick to conveying pipes if moisture control is not adequately maintained.

- Coke replacement ratios obtained by British Steel have not been bettered in any worldwide installation.

- System availability has exceeded 99 percent during several years of operation at British Steel.

- The unique variable speed, positive displacement CPC Macawber injectors provide superior flow control and measurement compared to other coal injection systems.

The joint development by British Steel and CPC Macawber of a process for the injection of granular coal into blast furnaces began in 1982 on the Queen Mary blast furnace at the Scunthorpe Works.(1,2) The objective of the development work was to inject granular coal into the furnace and test the performance of the CPC Macawber equipment with a wide range of coal sizes and specifications. Based on Queen Mary's performance, coal injection systems were installed on Scunthorpe's Queen Victoria, Queen Anne and Queen Bess blast furnaces and on Blast Furnaces 1 and 2 of the Ravenscraig Works. Queen Victoria's system was brought on line in November, 1984 and Queen Anne's in January, 1985. The Ravenscraig systems were started up in 1988. The success of the GCI systems at Scunthorpe and Ravenscraig led Bethlehem to conclude that the system could be applied successfully to large blast furnaces using domestic coals.

IV. INSTALLATION DESCRIPTION

A simplified flow diagram of the coal handling system at Burns Harbor is shown in Figure 4. The Raw Coal Handling Equipment and the Coal Preparation Facility includes the equipment utilized for the transportation and preparation of the coal from an existing railroad car dumper until it is prepared and stored prior to passage into the Coal Injection Facility; the Coal Injection Facility delivers the prepared coal to the blast furnace tuyeres.

Raw Coal Handling. Coal for this project is transported by rail from coal mines to Burns Harbor similar to the way in which the plant now receives coal shipments for the coke ovens. The coal is unloaded using a railroad car dumper, which is part of the blast furnace material handling system. A modification to the material handling system was made to enable the coal to reach either the coke ovens or the coal pile for use at the Coal Preparation Facility.

Raw Coal Reclaim. The raw coal reclaim tunnel beneath the coal storage pile contains four reclaim hoppers in the top of the tunnel. The reclaim hoppers, which are directly beneath the coal pile, feed a conveyor in the tunnel. The reclaim conveyor transports the coal at a rate of 400 tons per hour above ground to the south of the storage pile. A magnetic separator is located at the tail end of the conveyor to remove tramp ferrous metals. The conveyor discharges the coal onto a vibrating screen to separate coal over 2 inches from the main stream of minus 2-inch coal. The oversized coal passes through a precrusher which discharges minus 2-inch coal. The coal from the precrusher joins the coal that passes through the screen and is conveyed from ground level by a plant feed conveyor to the top of the building that houses the Coal Preparation Facility.

Coal Preparation. The plant feed conveyor terminates at the top of the process building that houses the Coal Preparation Facility. Coal is transferred to a distribution conveyor, which enables the coal to be discharged into either of two steel raw coal storage silos. The raw coal silos are cylindrical with conical bottoms and are completely enclosed with a vent filter on top. Each silo holds 240 tons of coal, which is a four-hour capacity at maximum injection levels. Air cannons are located in the conical section to loosen the coal to assure that mass flow is maintained through the silo.

Coal from each raw coal silo flows into a feeder which controls the flow of coal to the preparation mill. In the preparation mill, the coal is ground to the desired particle size. Products of combustion from a natural gas fired burner are mixed with recycled air from the downstream side of the process and are swept through the mill grinding chamber. The air lifts the ground coal from the mill vertically through a classifier where oversized particles are circulated back to the mill for further grinding. The proper sized particles are carried away from the mill in a 52-inch pipe. During this transport phase, the coal is dried to 1-1.5% moisture. The drying gas is controlled to maintain oxygen levels below combustible levels. There are two grinding mill systems; each system produces 30 tons per hour of pulverized coal or 60 tons per hour of granular coal.

The prepared coal is then screened to remove any remaining oversize material. Below the screens, screw feeders transport the product coal into one of four 180-ton product storage silos and then into a weigh hopper in two-ton batches. The two-ton batches are dumped from the weigh hopper into the distribution bins which are part of the Coal Injection Facility.

Coal Injection. The Coal Injection Facility includes four distribution bins located under the weigh hoppers described above. Each distribution bin contains 14 conical-shaped pant legs. Each pant leg feeds an injector which allows small amounts of coal to pass continually to an injection line. Inside the injection line, the coal is mixed with high-pressure air and is carried through approximately 600 feet of 1-1/2-inch pipe to an injection lance mounted on each of the 28 blowpipes at each furnace. At the injection lance tip, the coal is mixed with the hot blast and carried into the furnace raceway. The 14 injectors at the bottom of the distribution bin feed alternate furnace tuyeres. Each furnace requires two parallel series of equipment, each containing one product coal silo, one weigh hopper, one distribution bin and 14 injector systems.

V. PROJECT MANAGEMENT

The demonstration project is divided into three phases:

Phase I	Design
Phase II	Construction and Start-up
Phase III	Operation and Testing

Phase I was completed in December 1993 and construction was completed in January 1995. Coal was first injected in four tuyeres of D furnace on December 18, 1994. The start-up period continued to November 1995 at which time the operating and testing program started. The testing of coals (Phase III) is expected to continue to July 1998.

The estimated project cost summary is shown in Table I. The total cost is expected to be about $191 million. Additional information on project management was presented at the previous CCT Conferences. (3,4)

Facility Start-Up

The coal injection facilities were fully started in January 1995 and by early June the coal injection rate on both furnaces had stabilized at 140 lbs/ton.(5) There were facility start-up problems in January and February, but by mid-year the coal preparation and delivery systems were operating as designed. The injection rate on C furnace was increased through the summer months and was over 200 lbs/ton for September, October and November. The injection rate on D furnace was kept in the range of 145-150 lbs/ton during the second half of the year.

In December 1995, severe coal weather caused coal handling and preparation problems that were not experienced during start-up in early 1995. The most severe problem was due to moisture condensing on the inside walls of the prepared coal silos. The moisture caked the coal and eventually blocked the injectors below the silos. As a result, coal injection on C furnace was stopped in mid-December and the coal silos were emptied and cleaned. In order to prevent condensation in the future, the top and sides of the C furnace coal silos were insulated. The D furnace silos were insulated in January 1996. The insulation has prevented any reoccurrence of blocked injectors due to caked coal.

VI. TEST PROGRAM

The objective of the overall test program is to determine the effect of coal grind and coal type on blast furnace performance. The start-up operation was conducted with a high volatile coal from eastern Kentucky with 36% volatile matter, 8% ash and 0.63% sulfur. The coal preparation system was operated to provide granular coal throughout the start-up period.
The coal injection rates and coke rates for C and D furnaces during 1995 and 1996 are shown in Figures 5 and 6, respectively.

Initial Results with Granular Coal

The first comparison of interest was the blast furnace results with coal injection versus natural gas injection. A typical monthly operating period with natural gas is shown in Table II along with the first full month (April 1995) of coal injection on D furnace. The coke rate during the initial period with coal injection at 150 lbs/ton was 55 lbs greater than with natural gas at 140 lbs/ton. This was not unexpected. It has been established in the past that 1.3 to 1.4 lbs of coke are replaced by one pound of natural gas. The initial expectation for injected coal was that 0.8-0.9 lbs of coke would be replaced by one pound of coal. Also notable in Table II is the 44 lbs/ton slag volume increase that accompanies the injected coal practice. This additional slag volume is a direct result of the coal ash. Slag sulfur also increased from 0.87% to 1.09% due to the sulfur in the coal. In order to maintain hot metal chemistry control, the slag chemistry has been altered slightly to provide more sulfur removal capacity. Another item of interest is the large decrease in the hydrogen content of the top gas when coal is injected.

The next process benchmark that was important to operating personnel was the amount of injected coal necessary to return the furnace coke rate to the levels previously experienced with natural gas. This is shown by the September 1995 operating data from C furnace in Table II. After gaining experience with coal injection and establishing a steady operation at the coal preparation facility, an injection rate of 210 lbs/ton resulted in a comparable coke rate to the natural gas experience. The September operation is notable with regard to several process parameters. The wind rate has been reduced along with an increase in the oxygen enrichment level. Increasing the oxygen content of the hot blast resulted in a higher flame temperature which, in turn, enhances coal combustion in the tuyere zone. The flame temperature increased by 270 F with coal injection versus the previous practice with natural gas. Slag volume and chemistry have changed very little except for the higher sulfur content that is directly proportional to the increased injected coal rate. A decrease in the furnace permeability during this period is also apparent.

Permeability is a parameter used to show the amount of hot blast that is blown at a given pressure drop through the furnace. In general, a higher permeability means the flow of reducing gases through the furnace is smoother. The increase in coal injection from 150 to 210 lbs/ton caused a significant reduction in the furnace permeability. Figure 7 shows the effect of coal injection on permeability in both furnaces through July 1996. The reduction of furnace permeability is a major concern for higher levels of coal injection.

Table III shows the coals used during 1995 at Burns Harbor. The most important difference between the eastern Kentucky high volatile coal and the low volatile coals is the total carbon content. The effect of higher coal carbon content is shown with the blast furnace results from November 1994 and April 1995 in Table IV. The coke rate is about 50 lbs/ton lower with the low volatile coals compared to the high volatile coal.

Another advantage of low volatile coal was a substantial reduction in electrical energy at the coal grinding facility due to the softness of the coal. The Hargrove Grindability Index of the low volatile coals is in the range of 90 to 101 compared to 46 for the high volatile coal.

Table IV also shows the recent operation of July 1996 using low volatile coal. The coal rate has increased to about 270 lbs/ton, the furnace coke rate has been reduced to 660 lbs/ton and the permeability has stabilized at 1.19. The lower blast pressure seen for the July 1996 period is also an indication of better furnace permeability. This was accomplished with increased use of blast moisture to produce more hydrogen in the bosh gas. This is shown by the increase in hydrogen content of the top gas. The increased hydrogen content results in a lower density bosh gas and, therefore, reduced gas flow resistance through the furnace stack.

Coke/Coal Replacement Ratio

The quantity of furnace coke that is replaced by an injected fuel is an important aspect of the overall value of the injectant on the blast furnace operation. A detailed analysis of the furnace coke/coal replacement ratio for the C and D furnaces at Burns Harbor has been completed.

The replacement ratio for a blast furnace injected fuel is defined as the amount of coke that is replaced by one pound of the injectant. However, there are many furnace operating factors, in addition to the injectant, that affect the coke rate. In order to calculate the coke replaced by coal only, all other blast furnace operating variables that result in coke rate changes must be adjusted to some base condition. After adjusting the coke rate for changes caused by variables other than the coal, the remaining coke difference is attributed to the injected coal.

This evaluation was conducted with monthly average operating data compared to an appropriate base period for each furnace. Twenty-five months of data on both furnaces through the second quarter of 1996 were used in this evaluation.

The adjusted coke rates and the injected coal are plotted in Figure 8 along with the best fit regression line. The slope of the best fit line shows that coke/coal replacement is 0.96. This is an excellent replacement ratio and is significantly better than the 0.8-0.9 replacements reported by other coal injection operations.

The major conclusion of the test work to date is that granular coal performs very well in large blast furnaces. All other blast furnace coal injection systems use pulverized coal and some believed that pulverized coal was a requirement for large furnaces. The injection rates at Burns Harbor are not yet at the 400 lbs/ton level achieved by some, but there is nothing in the Burns Harbor experience to date that precludes higher injection rates with granular coal. The Burns Harbor furnaces will probably be limited to injection rates lower than 400 lbs/ton because of the lack of burden distribution equipment like moveable armor or a bell-less top, but this is a furnace limitation and not a coal size limitation.

Future Testing

The testing of different coals will continue through 1997. The first test will be with a processed sub-bituminous coal from the Encoal Corporation in Gillette, Wyoming. The Encoal operation has also been supported by the Clean Coal Technology program. About 13,000 tons of Process Derived Fuel (PDF) from Encoal will be used in the Burns Harbor furnaces for about one week.

A trial will be conducted to determine the effect of granular versus pulverized coal. The same low volatile coal that has been injected through most of 1996 with a granular size will be pulverized to 70-80% minus 200 mesh for a one month trial. This will be the first time that a direct comparison of granular versus pulverized coal will be conducted on the same blast furnace.

Additional testing to be conducted in 1997 includes a high ash content coal and a high volatile coal. The high ash content coal will be similar to the base low volatile coal in all respects except the ash. This trial will provide a unique opportunity to determine the effect of coal ash in the blast furnace process.

The test with a high volatile coal will be a direct comparison to the base low volatile coal at a high injection rate. This test along with the high ash test will provide a sound basis for economic evaluations of alternative coal sources for all U.S. blast furnace operations with coal injection.

VII. REFERENCES

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2. D. S. Gathergood and G. Cooper, "Blast Furnace Injection - Why Granular Coal"? Steel Technology International, 1988.

3. D. Kwasnoski and L. L. Walter, "Blast Furnace Granular Coal Injection", Second Annual Clean Coal Technology Conference, Atlanta, GA, September 1993.

4. D. Kwasnoski and L. L. Walter, "Blast Furnace Granular Coal Injection", Third Annual Coal Technology Conference, Chicago, IL, September 1994.

5. L. L. Walter, R. W. Bouman and D. G. Hill, "Blast Furnace Granular Coal Injection", Fourth Annual Coal Technology Conference, Denver, CO, September 1995.

TABLE I. ESTIMATED GRANULAR COAL INJECTION PROJECT COST SUMMARY

	$ Million	
Phase I Design	5.19	
Phase II Construction and Start-Up	133.85	
Phase III Operation	51.61	
Total Cost	190.65	
Cost Sharing		
DOE	31.26	(16.4%)
Bethlehem Steel	159.39	(83.6%)
	190.65	

TABLE II

BURNS HARBOR BLAST FURNACE
RESULTS - NATURAL GAS COAL INJECTION

	D Furnace November 1994	D Furnace April 1995	C Furnace September 1995
Fuel Rate, lbs/ton			
Natural Gas	140	-	-
Coal	-	150	210
Coke	743	798	745
Blast Conditions:			
Reported Wind, MSCFM	171	174	164
Oxygen Enrichment, %	4.0	2.4	5.2
Moisture, Grs/SCF	6.0	16.0	8.5
Blast Pressure, psig	38.0	38.6	38.9
Flame Temperature, F	3685	3793	4062
Top Temperature, F	240	252	213
Hot Metal Analysis, %			
Silicon	.52	.56	.62
Sulfur	.040	.041	.035
Slag Analysis, %			
SiO_2	37.74	36.31	36.57
Al_2O_3	9.64	9.70	9.50
CaO	36.50	38.21	37.71
MgO	12.20	12.08	12.31
Sulfur	0.87	1.09	1.19
Slag Volume, lbs/ton	393	437	437
Furnace Permeability	1.52	1.50	1.30
Top Gas Analysis:			
H_2,%	7.33	3.05	3.13
BTU/SCF	92.8	82.6	88.1

TABLE III

COALS USED AT BURNS HARBOR IN 1995

Coal	Eastern Ky. High Volatile	Virginia Low Volatile	Virginia Low Volatile	W. Virginia Low Volatile	W. Virginia Low Volatile
Vol. Matter, %	36.0	18.0	19.6	16.5	18.4
Ash, %	7.50	5.30	5.16	5.75	5.50
Sulfur, %	0.63	0.80	0.75	0.58	0.77
Moisture*, %	3.0	1.5	1.5	1.5	1.4
Gross Heating Value, BTU/lb	13900	14900	15029	14550	14775
Hargrove Grindability Index	46	100	101	94	90
Ultimate Analysis, %					
C	78.0	87.0	87.0	86.0	85.3
O	7.00	1.40	1.52	2.20	3.07
H	5.4	4.4	4.2	4.2	4.0

* After drying and grinding

TABLE IV

BURNS HARBOR C FURNACE RESULTS WITH COAL INJECTION

	September 1995	November 1995	July 1996
Coal Type	High Volatile	Low Volatile	Low Volatile
Fuel Rate, lbs/ton			
Coal	210	210	269
Coke	745	694	660
Blast Conditions:			
Reported Wind, SCFM	164	163	154
Oxygen Enrichment, %	5.2	4.6	5.6
Moisture, Grs/SCF	8.5	7.6	16.3
Blast Pressure, psig	38.9	39.4	38.6
Flame Temperature, F	4062	3996	3949
Top Temperature, F	213	210	244
Hot Metal Analysis, %			
Silicon	.62	.45	.49
Sulfur	.035	.041	.039
Slag Analysis, %			
SiO_2	36.57	37.26	37.04
Al_2O_3	9.50	8.73	8.91
CaO	37.71	38.17	38.56
MgO	12.31	12.28	11.94
Sulfur	1.19	1.25	1.31
Slag Volume, lbs/ton	437	428	434
Furnace Permeability	1.30	1.26	1.19
Top Gas Analysis:			
H_2%	3.13	3.15	4.31
BTU/SCF	88.1	84.1	89.7

FIGURE 1

THE BLAST FURNACE COMPLEX

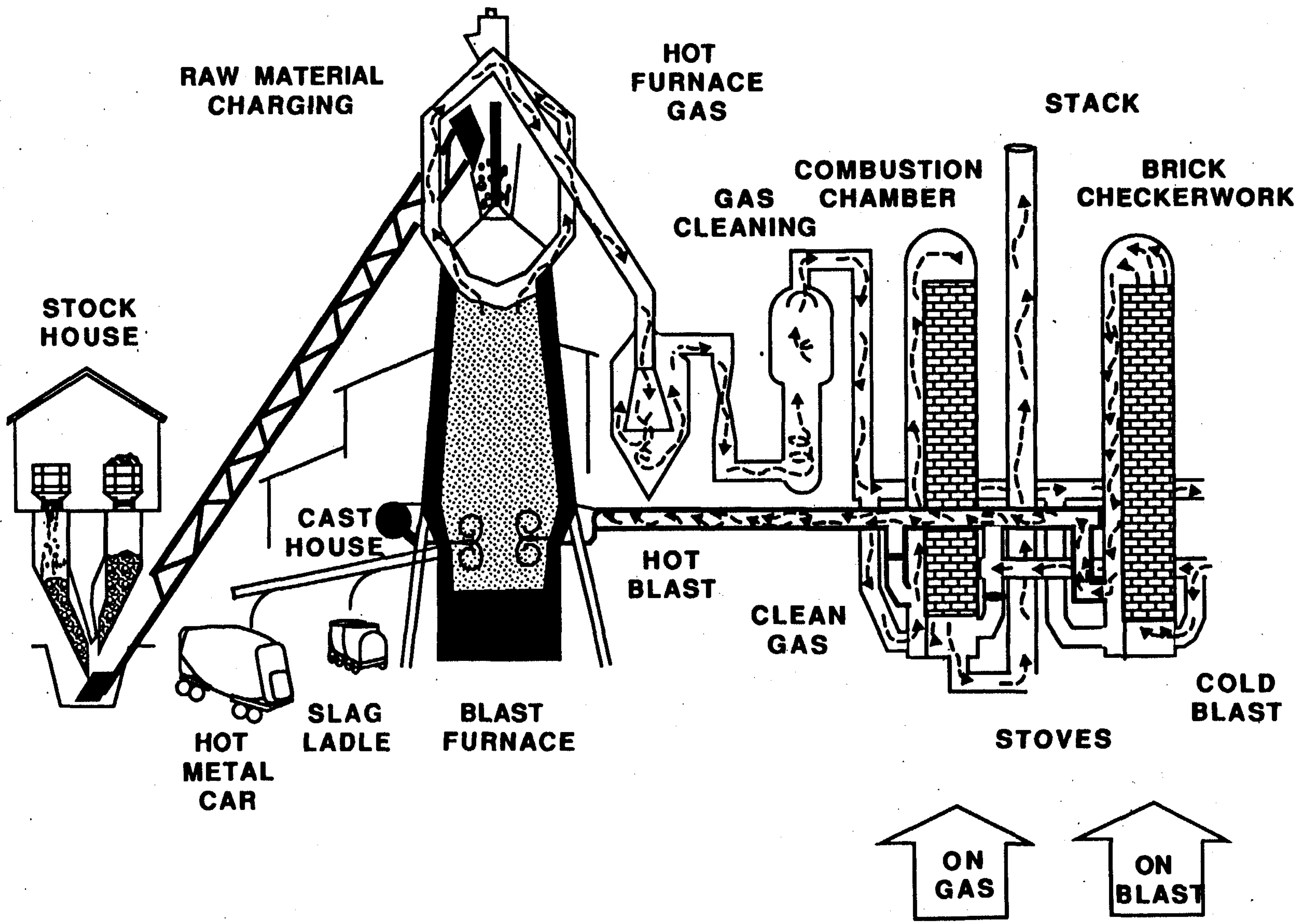


FIGURE 2

ZONES IN THE BLAST FURNACE

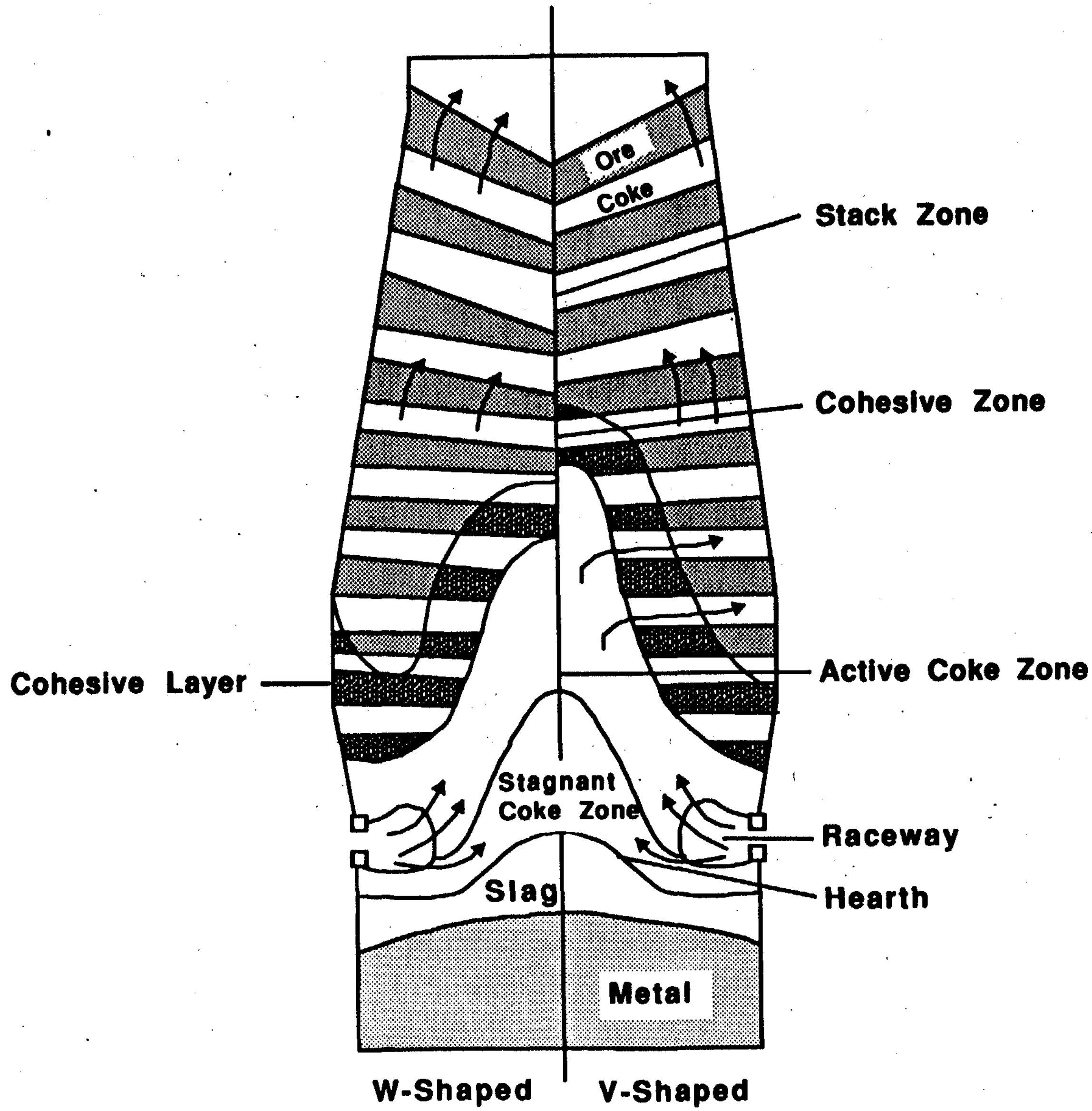


FIGURE 3

APPLICATION OF COAL INJECTION

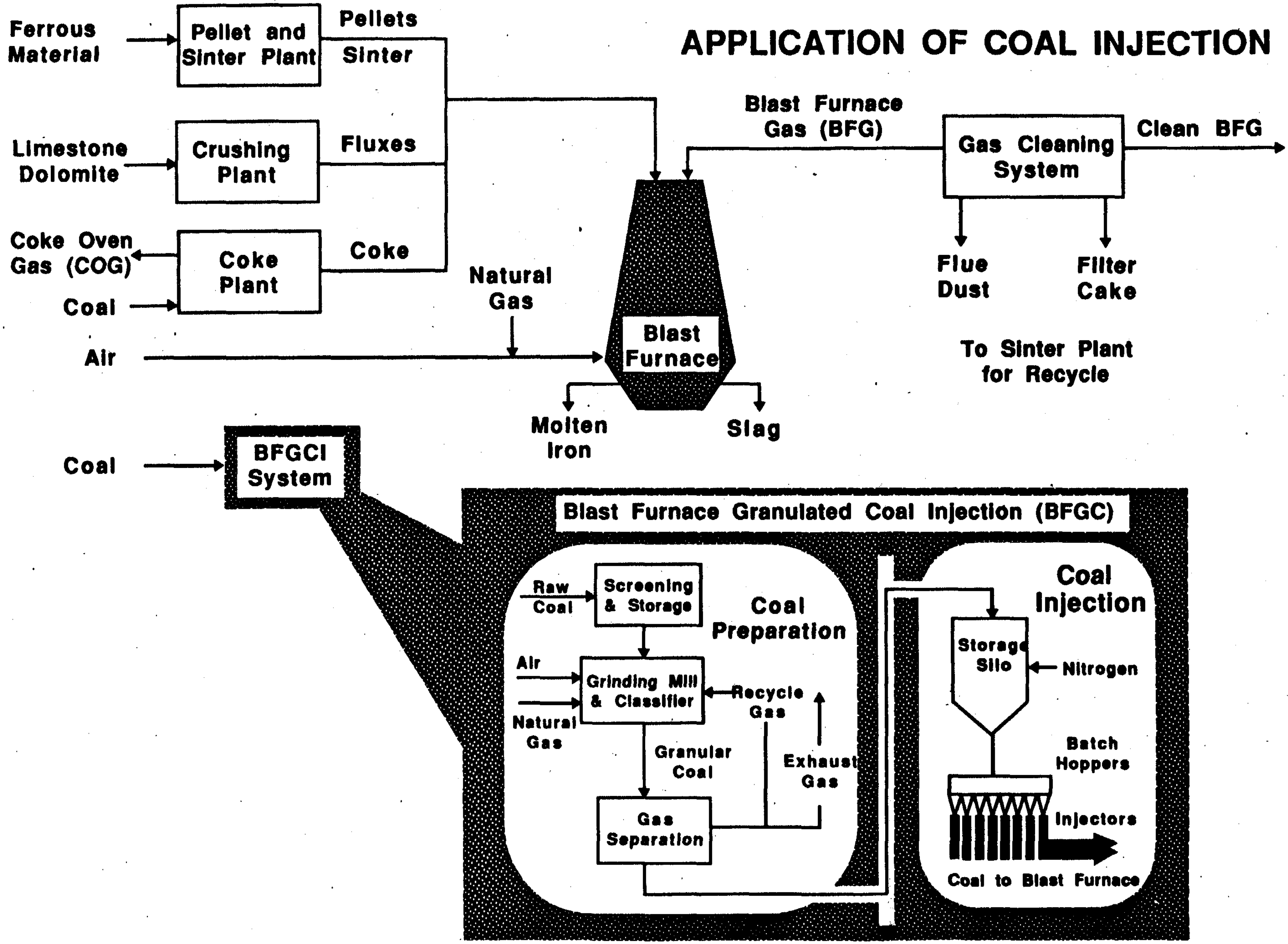


FIGURE 4. COAL PREPARATION AND INJECTION FACILITIES
BURNS HARBOR PLANT

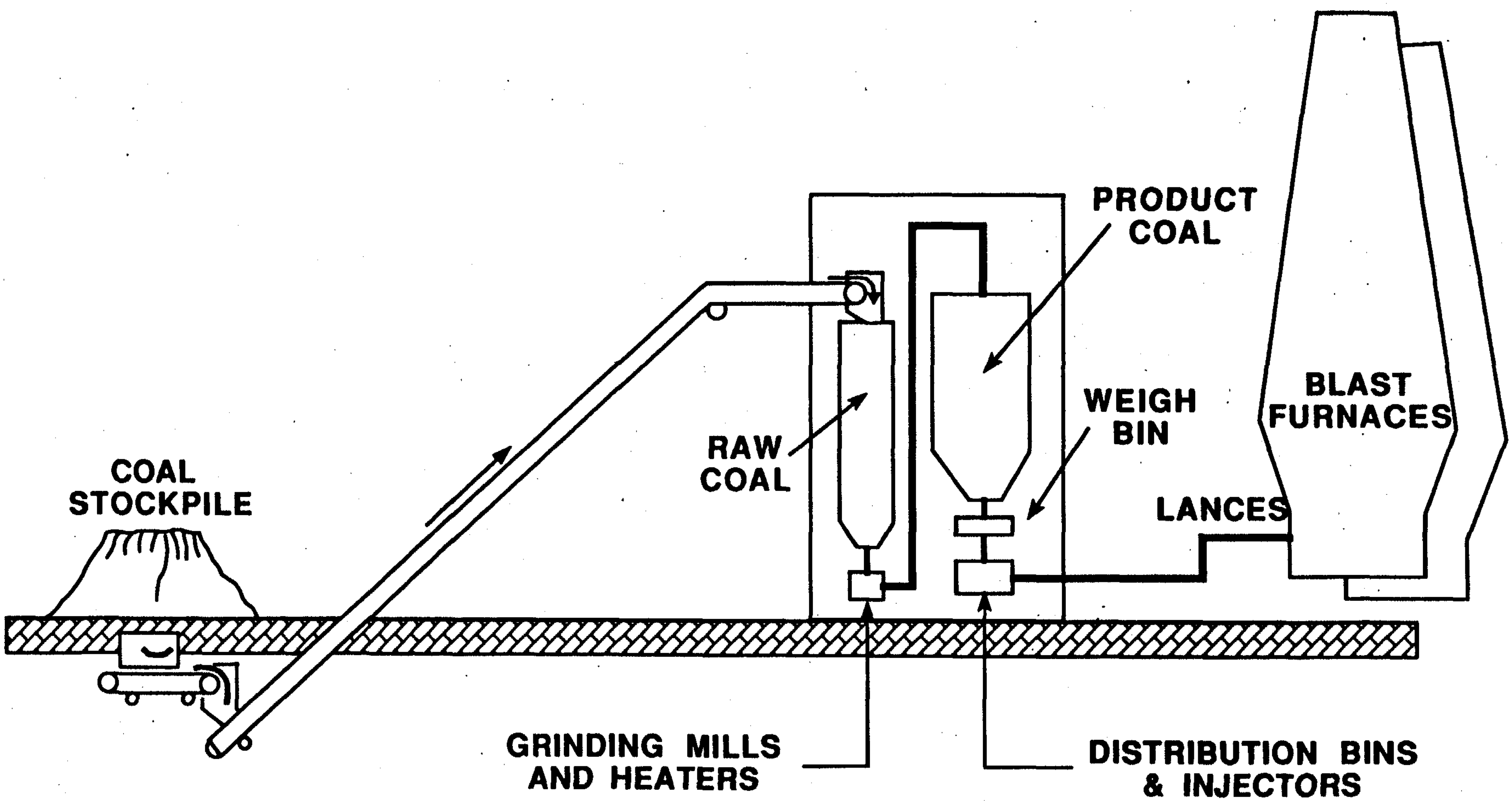


FIGURE 5

BURNS HARBOR C FURNACE COAL and COKE RATES

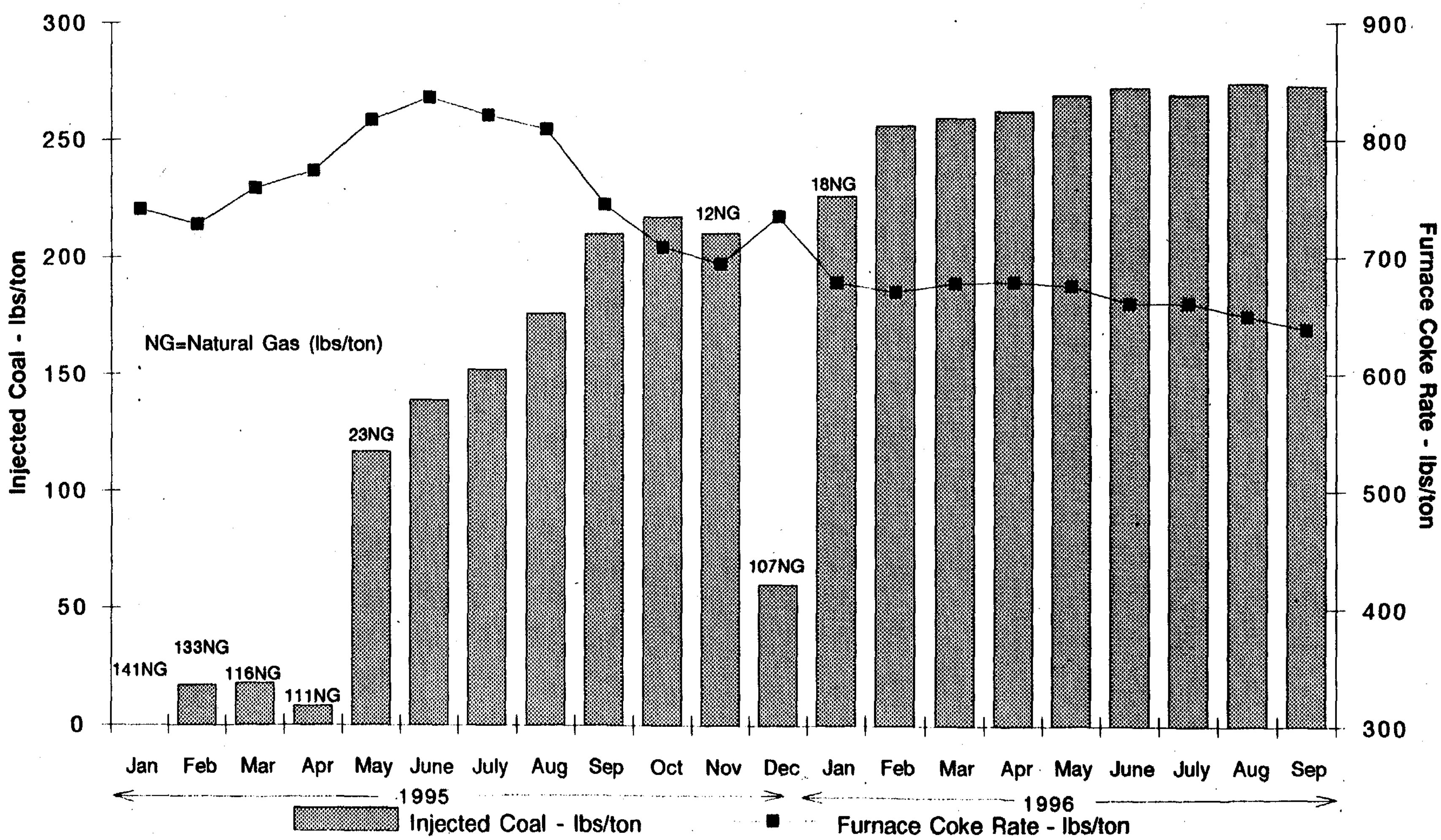


FIGURE 6

BURNS HARBOR D FURNACE COAL and COKE RATES

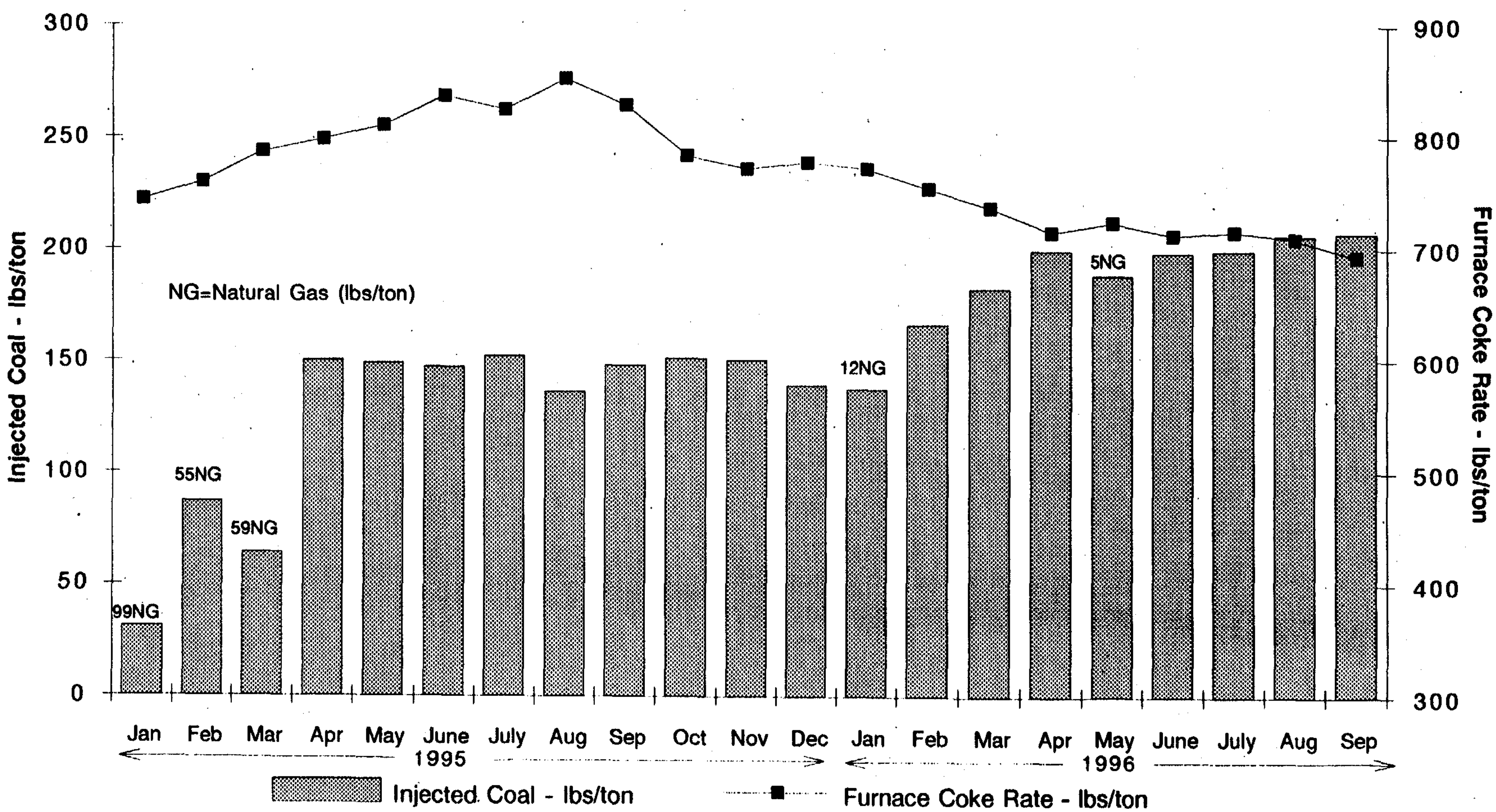
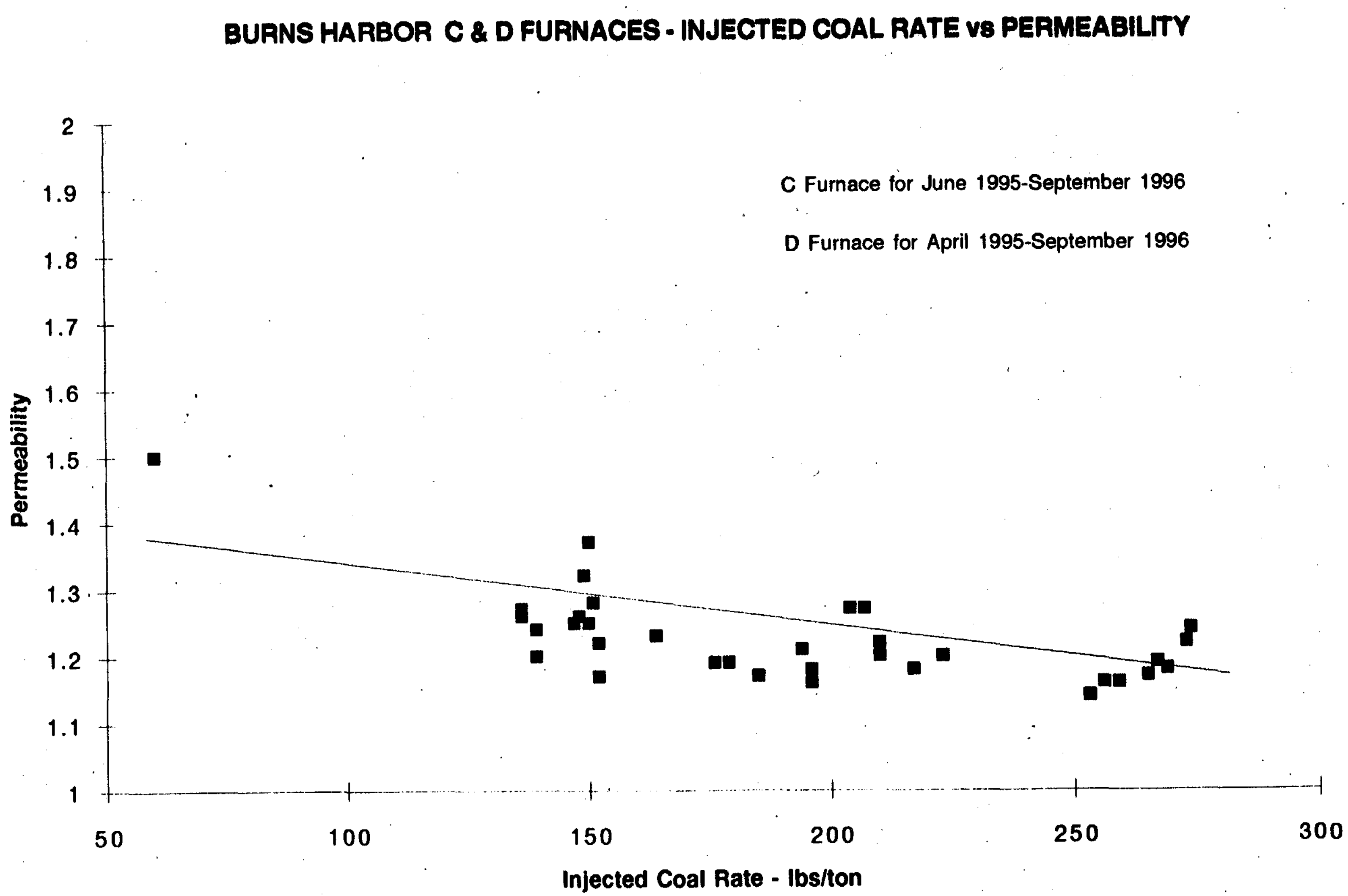
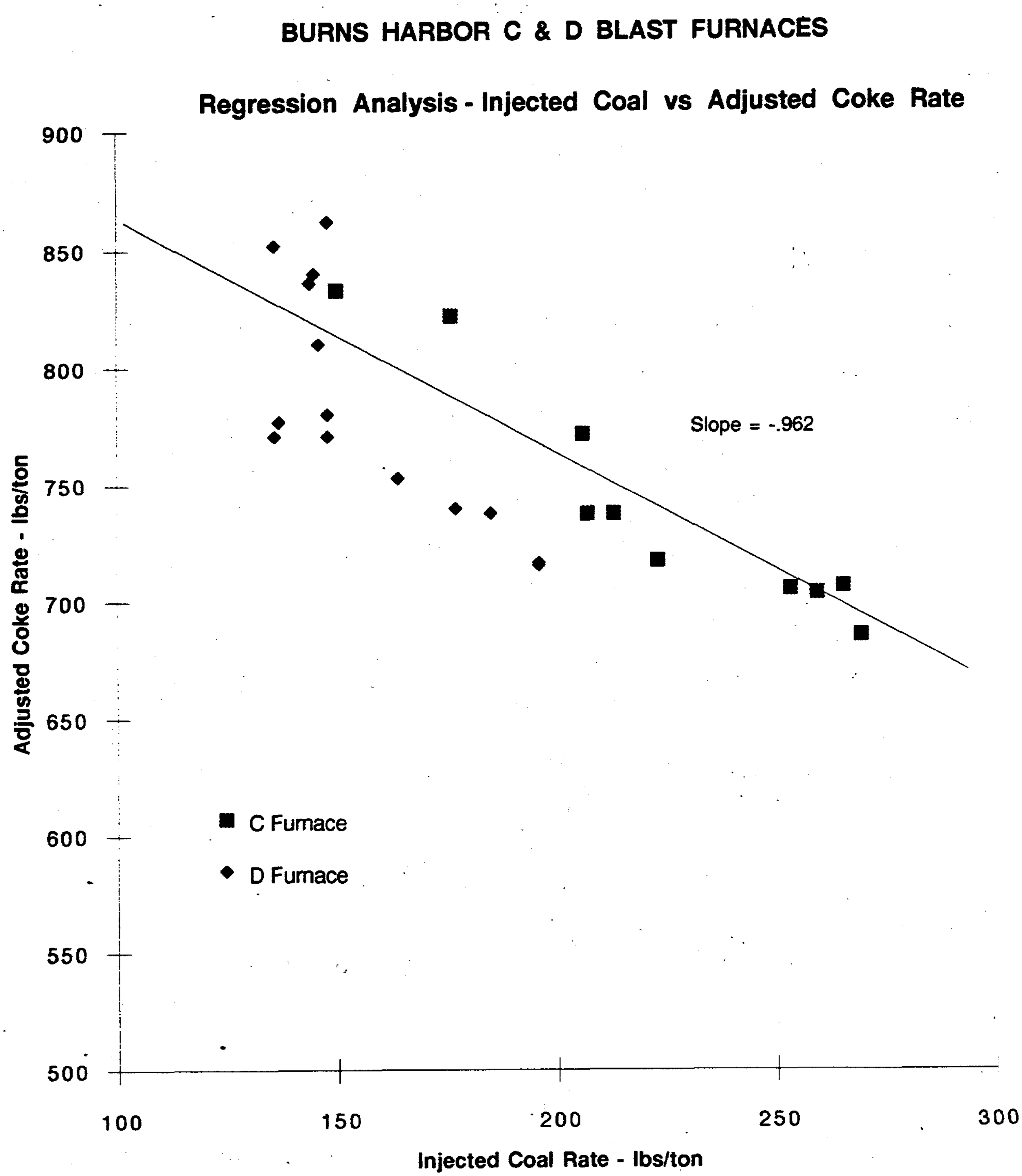


FIGURE 7



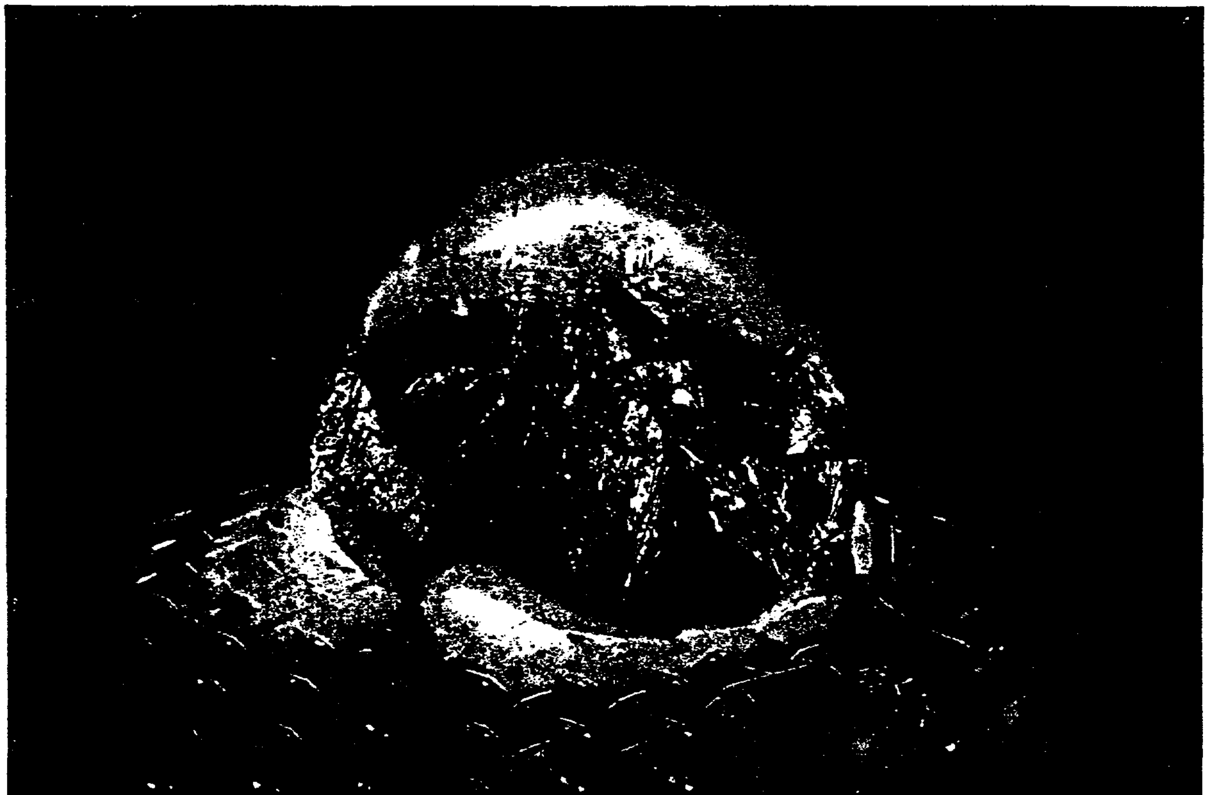
BURNS HARBOR C & D FURNACES - INJECTED COAL RATE vs PERMEABILITY
C Furnace for June 1995-September 1996
D Furnace for April 1995-September 1996
Permeability
2
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
50
100
150
200
250
300
Injected Coal Rate - lbs/ton

FIGURE 8



BURNS HARBOR C & D BLAST FURNACES
Regression Analysis - Injected Coal vs Adjusted Coke Rate
Adjusted Coke Rate - lbs/ton
900
850
800
750
700
650
600
550
500
100
150
200
250
300
Injected Coal Rate - lbs/ton
Slope = -.962
C Furnace
D Furnace

CPICOR™



Clean Power from Integrated Coal-Ore Reduction

By

Reginald Wintrell	**Geneva Steel**
Robert N. Miller	**Air Products**
Edmund J. Harbison	**Air Products**
Mark O. LeFevre	**Air Products**
Kevin S. England	**Centerior Energy**

INDEX

LIST OF FIGURES

DISCLAIMER

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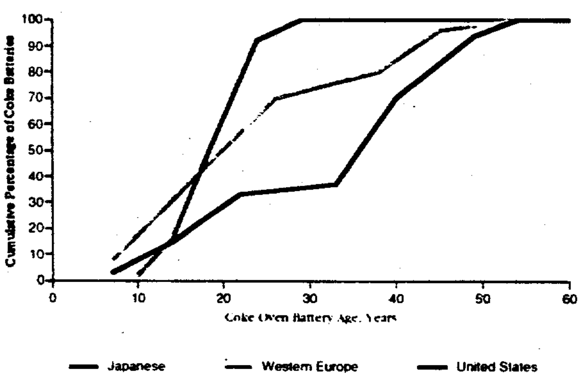
BACKGROUND

A growing coke shortage is impacting the U.S. ability to produce iron and steel. Driven by environmental concerns of the sixties, the government imposed increasingly stringent requirements upon the U.S. coking industry to substantially lower the level of airborne pollutants. The U.S. steel industry, subjected to the economics of the '70s and '80s and unable to justify the building of new coke units or the environmental modifications required to save its antiquated coking batteries, purchased foreign coke (Figure 1). The impact of this policy in the mid '90s has been a rapid depletion of the world's surplus in coke production. This depletion will be further impacted as the Clean Air Act Amendments of 1990 take effect.

Age of U.S. Coke Plants FIG.1



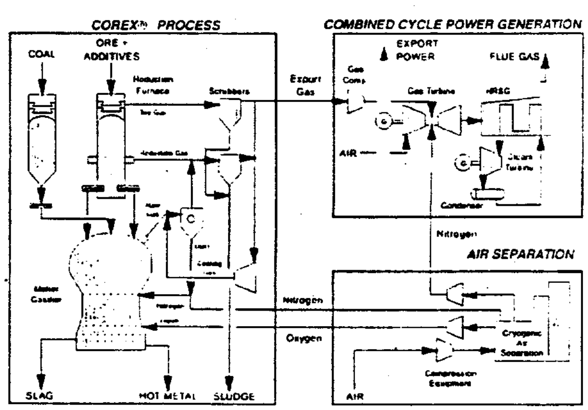
The U.S. steel industry, in order to maintain its basic iron production, is thus moving to lower coke requirements and to the cokeless or direct production of iron. The U.S. Department of Energy (DOE), in its Clean Coal Technology programs, has encouraged the move to new coal-based technology. The steel industry, in its search for alternative direct iron processes, has been limited to a single process, COREX®. The COREX® process, though offering commercial and environmental acceptance, produces a copious volume of offgas which must be effectively utilized to ensure an economical process. This volume, which normally exceeds the internal needs of a single steel company, offers a highly acceptable fuel for power generation. The utility companies seeking to offset future natural gas cost increases are interested in this clean fuel.

INTRODUCTION

The COREX® smelting process, when integrated with a combined cycle power generation facility (CCPG) and a cryogenic air separation unit (ASU), is an outstanding example of a new generation of environmentally compatible and highly energy efficient "Clean Coal" technologies. This combination of highly integrated electric power and hot metal co-production, has been designated CPICOR™. "Clean Power from Integrated Coal/Ore Reduction." A consortium of leading companies who recognized the dilemmas of the U.S. steel and utilities industries have jointly proposed to the U.S. Department of Energy a collaborative effort to commercially demonstrate the CPICOR process using an advanced U.S. combined cycle power generation unit (Figure 2). The consortium further proposed to demonstrate optimum efficiency by combining the power generation and air separation units. The proposal was accepted for negotiation under Clean Coal V utilizing a 3,200 tons per day COREX® unit.

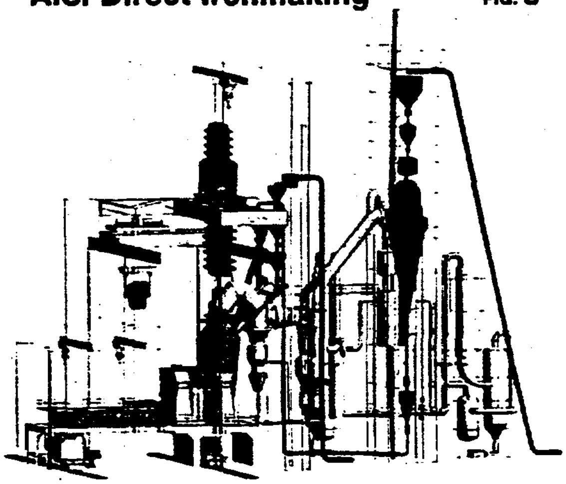
The consortium's selection of the COREX® process was based upon several factors. The U.S. urgently requires demonstration of direct iron production on a full commercial scale. The COREX®, as demonstrated by the operating unit at ISCOR and the unit under construction at Pohang, is the only process ready for upgrading to a production capacity suitable for the U.S. The Environmental Protection Agency requires an environmentally acceptable process. The COREX® process has fully demonstrated its compliance. The domestic steel industry is seeking economic operating incentives over the present coke plant/blast furnace route.

CPICOR Conceptual Flow Diagram FIG. 2



AISI Direct Ironmaking

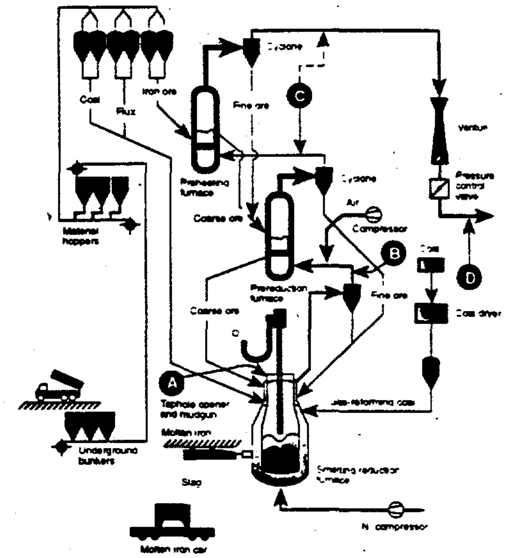
FIG. 5



Smelter vessel and lance
Offgas cleaning and tempering loop
Pre-reduction shaft furnace and ore feed
Coal feed system

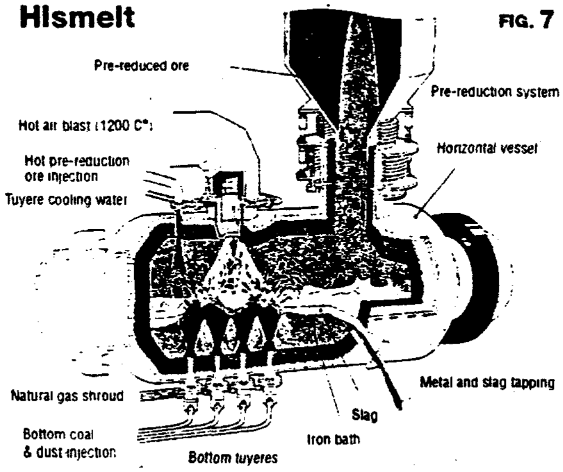
DIOS

FIG. 6



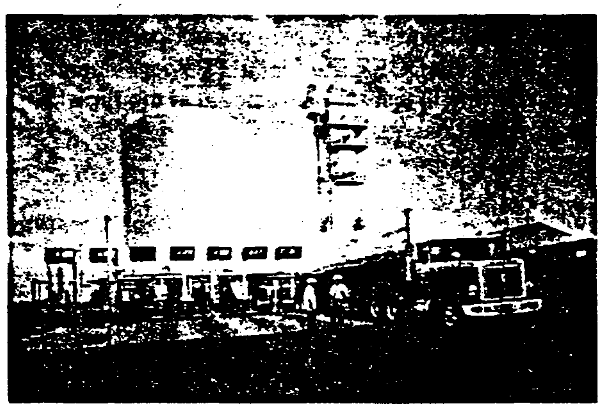
HIsmelt

FIG. 7



ASU Facility

FIG. 8



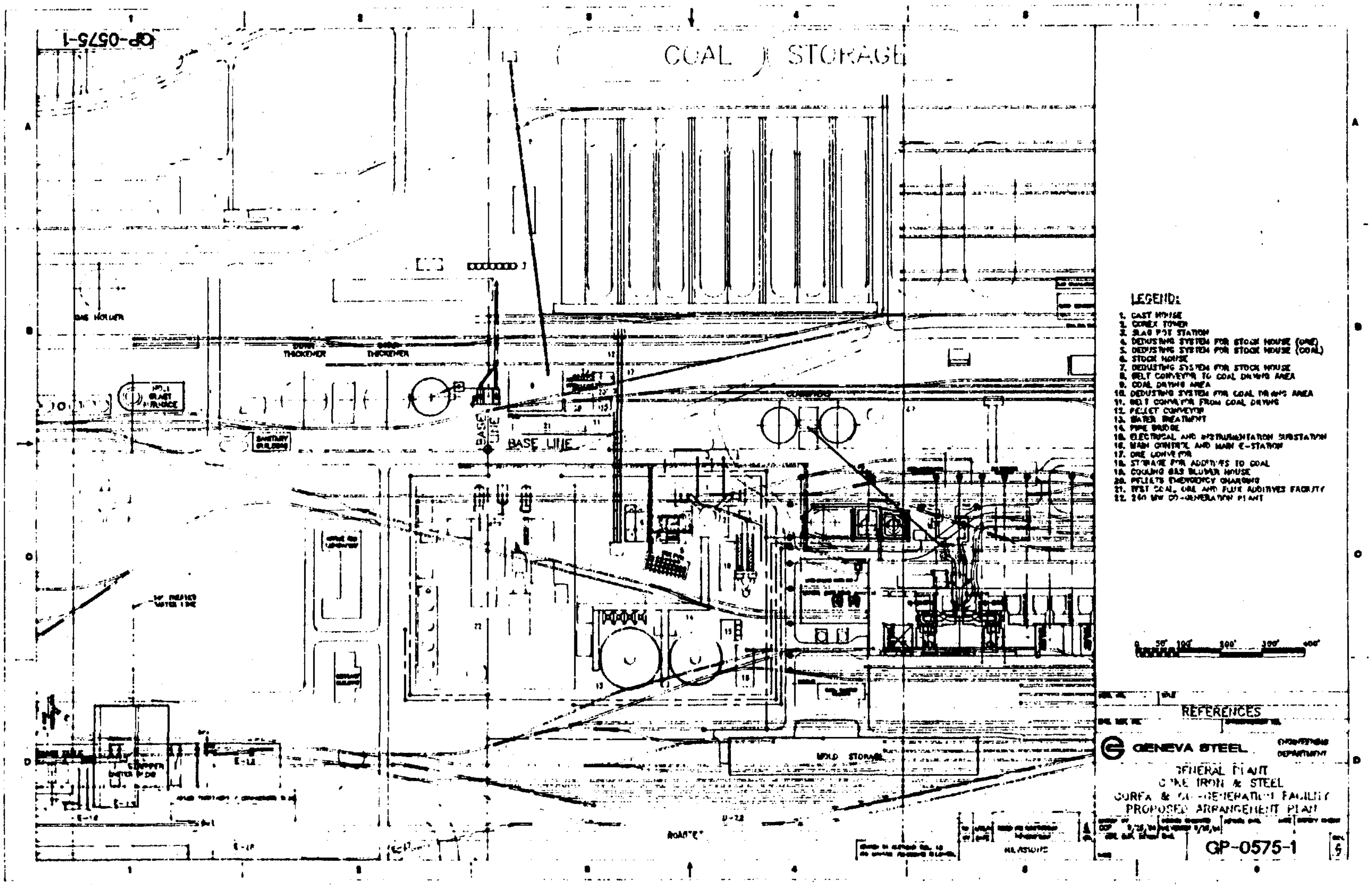
industry, hundreds of commercial oxygen plants have been built, and presently more than 70,000 tons per day of oxygen capacity exists in the U.S. The ASU is proven, reliable, and highly efficient and will be integrated with the CCPG and COREX® within the CPICOR process. CPICOR will expand the U.S. coal base by including a wider range of coals for the simultaneous production of iron and power and will provide an integrated environmental solution for the economical revival of our steel, coal and power industries.

PROJECT OBJECTIVES

The project objectives are to demonstrate a scale up of the COREX® and its commercial integration with the advanced combined cycle power generation system. To date, the COREX® process has demonstrated the ability to produce 330,000 tons of hot metal per year on lump ore, with the generated gas used for inplant heating purposes. To be commercially viable in the U.S., the value of the generated gas must be optimized, such as by partial integration with power generation, and the COREX®

Site Location

FIG. 9



reducing gas. The gas exits the melter/gasifier and passes through the dust separation cyclone before it is cooled to 850°C and transferred into the reduction shaft furnace. The reduction furnace is fed 5,170 TPD of iron ore and pellets and 622 TPD of raw fluxes. The charge is reduced or calcined by the ascending reducing gas. During the ascent, the sulfur contained in the gas reacts with the reduced iron and the calcined lime and dolomite. The reduced iron and the calcined fluxes are fed by water-cooled screws into the melter/gasifier. In the melter/gasifier, the reduced iron is melted by heat generated from the partial oxidation of the coal. The sulfur released during the smelting process is chemically captured in a calcium-rich, basic slag. The hot metal and slag are tapped periodically from the furnace hearth. The molten metal is sent directly to the steel mill for processing and the tapped slag (1,114 TPD) is recovered and used in the same manner as blast furnace slag.

The spent reducing gas (or top gas) leaves the reduction shaft essentially desulfurized and is quenched and cleaned through a series of wet scrubbers equipped with cyclonic separators. The cleaned export gas (1,770 MMBTU/hr) is delivered to the CCPG facility where it is compressed, mixed with air and nitrogen, and burned in a gas turbine/generator system. Process steam is generated in a heat recovery steam generator (HRSG) by extraction of heat from hot turbine exhaust gases and the combustion of surplus export gas. The steam produced in the HRSG drives an electric generator. This results in a total of 250 MW of generated power. Alternatively, a portion of the COREX® gas can be combusted within Geneva's plant for such processes as soaking pits, reheating furnaces, etc., with the major portion being used for combined cycle power generation.

In addition to demonstrating the use of COREX® gas in a CCPG unit, another key innovative feature of the CPICOR design is the potential integration of the gas turbine with the ASU. The ASU is designed to produce nitrogen and 3,000 TPD of high purity oxygen for the COREX® process. A portion of the nitrogen produced by the ASU may be delivered to the gas turbine, mixed with the compressed hot gas stream, and used to boost power output.

INHERENT ADVANTAGES OF CPICOR

CPICOR technology, by virtue of its integral co-production of hot metal and power, offers a number of distinct technical and economic advantages over the competing commercial technology. The conventional method of producing hot metal from ore and coal involves two separate processes:

1) **Cokemaking** — Coal is heated to drive off volatile matter and produce "coke" to be used as both fuel and reducing agent in a smelting operation.

2) **Blast furnace smelting** — Ore, coke, limestone, and hot air are charged to reduce the ore and produce molten iron.

Approximately 30% of the coke oven gas produced during cokemaking is used to provide heat for the cokemaking operation. The excess gas is typically sent to a utility steam boiler where it is mixed with the surplus off-gas from the blast furnace to generate power. At comparable hot metal production rates, this technology generates only about one-fifth the power produced by CPICOR technology.

Highly Efficient Use of Coal

The energy efficiency of the CPICOR technology is over 30% greater than the competing commercial technology when considering only the effective production of hot metal and electric power. The higher efficiency of the CPICOR technology is due to the more effective use of the sensible heat and volatile matter than the cokemaking/blast furnace process, i.e. 55 to 40%. In addition, the CCPG achieves energy efficiencies of nearly 50% compared to a maximum of 34% with conventional coal-based power systems equipped with flue gas desulfurization.

Dramatic Reduction in Emissions

CPICOR technology is less complex and environmentally superior to conventional processes. All criteria air pollutants, particularly the acid rain precursors, SO_x and NO_x, are reduced by more than 85%. This reduction is due largely to the desulfurizing capability of the COREX® process, efficient control systems within the CCPG facility, and the use of oxygen in place of air in the COREX® process. The gaseous emissions from the CPICOR plant, resulting from the combustion of air and export processes without sacrificing the flexibility for commercial operation and the reliability of power or hot metal production.

FEASIBILITY OF CCPG INTEGRATION

Although this is the first CCPG application to be fueled with COREX® export gas, the proposed design is based on proven technology. Similarly sized and larger CCPG facilities have been designed and are currently in reliable operation today with 94% to 97% availability. The steam pressure levels selected for the CPICOR design are typical of those which have been used in power generation facilities for years. The proposed gas turbine system is a proven, reliable design with a considerable number of the candidate models currently in operation. There are many heat recovery steam generator (HRSG) units of similar design and size in operating CCPG installations. Many steam turbine/electric generator sets of the type and capacity proposed for CPICOR currently exist in electric power generation facilities and have been in operation for years. All other major equipment items for the CCPG facility are likewise based on existing technology and similarly sized units (Figure 13).

The fueling of a CCPG system gas turbine with low-BTU gas produced by the COREX® process is unique. However, fueling gas turbines with medium and low-BTU fuel is a technology which exists commercially and is being studied, developed, and optimized by the gas turbine manufacturers. Consuming COREX® export gas in a turbine presents some technical challenges not encountered with fired boiler combustion cycles. Particulates greater than 5 microns and alkali metals can lead to turbine blade erosion. In combination with H_2S and SO_2, these materials can lead to hot metal corrosion of the combustor and inlet transition duct as well as blading of the turbine section. These potential problems are addressed by adequate scrubbing and filtration of the export gas in the CPICOR design. The use of proven and reliable wet scrubber technology will provide over 95% dust removal. Performance data from the ISCOR operation shows the COREX® export gas has contaminant levels within the gas turbine manufacturers' maximum specifications.

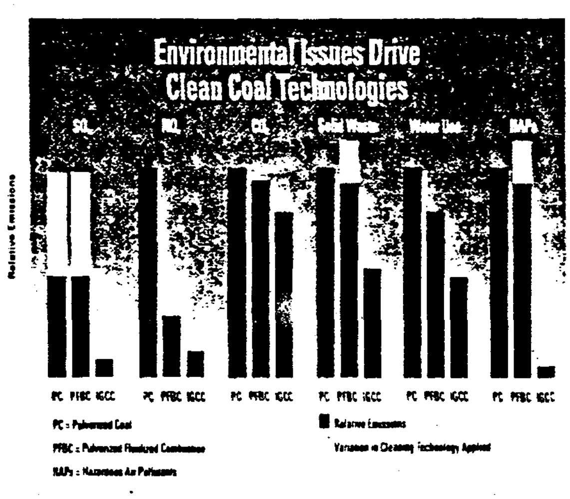
Considerable advancements have also been made in gas turbine hot section metal coatings. Cooling technologies have been developed to reduce the erosion and corrosion effects of firing offgases from processes such as COREX®. Westinghouse, Mitsubishi Heavy Industries (MHI), Siemens, ABB, General Electric, and European Gas Turbines (Ruston) all report capabilities to accept the COREX® export gas with only minor modifications to the gas turbine designs.

Combined Cycle Statistics

FIG. 13

Installed Combined Cycle Units

Installed Capacity (U.S.)	Over 66,000 megawatts
Operation Hours (U.S.)	Over 77 million hours
Power Range	Up to 350 MW per unit
Thermal Efficiencies	Up to 54+%
Availability	90 to 97%
Heat Rates	9000 to 6200 BTU/KWH



Coal Gasification Units

Plaquemines	two 104 MW units installed 1974
Cool Water	one 120 MW unit installed 1984
Emissions	1/10 of coal fired units

COMMERCIAL OUTLOOK

CPICOR is intended to replace commercial coke oven/blast furnace technology in the production of hot metal for use in steelmaking. The best candidates for utilizing CPICOR technology are existing integrated steel plants with blast furnaces and coke ovens nearing the end of their useful lives and located where the local electric utility requires additional capacity. While commercialization of the COREX® process is driven primarily by the need for an environmentally sound source of hot metal for the steel industry, the production of electric power from the COREX® export gas is key to the economic competitiveness of the technology. Thus, commercialization will be facilitated by the ability of this project to obtain an attractive price for the power created by the plant.

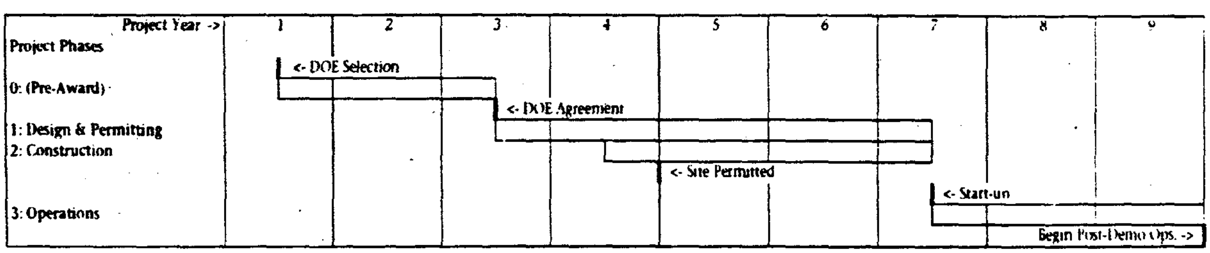
Conventional coke oven/blast furnace technology is too expensive to be utilized as replacement units or to expand domestic ironmaking capacity. Recent studies [2,3,4] conclude that no new coke batteries will be built in the United States. Of the existing 79 coke oven batteries, 40 are thirty years of age or older and are due for either replacement or major rebuilds.

As a consequence of the Clean Air Act Amendments of 1990, the emissions from existing coke ovens must be reduced substantially over the next several years. It has been estimated that the total capital investment for rebuilding or replacing current capacity could be in the range of $4 to $6 billion. The capital cost of coke ovens is about $166 per ton of equivalent hot metal capacity. Coupled to the cost of a blast furnace rebuild at $155 per ton equivalent hot metal capacity, the investment in a new COREX® facility at approximately $255 per ton compares favorably on a capital basis.

If the iron and steel industry is to continue to produce liquid iron in the form of hot metal, a new technology must be developed and installed. Future competition to COREX® is likely to come from the new direct ironmaking processes being developed in both Japan (the DIOS process, Figure 6) and in the U.S. (the AISI process, Figure 5). Both of these processes produce iron and a lower calorific value export gas directly from iron ore and coal. However, the development of the COREX® technology is 8 to 12 years ahead of these other processes. Consequently, COREX®/CPICOR should become the technology of choice as domestic ironmaking capacity reaches the end of its useful life.

Project Time Line

FIG. 14



Role Of The Liquids From Coal Process In The World Energy Picture

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ABSTRACT

ENCOAL Corporation, a wholly owned indirect subsidiary of Zeigler Coal Holding Company, has essentially completed the demonstration phase of a 1,000 Tons per day (TPD) Liquids From Coal (LFC™) plant near Gillette, Wyoming. The plant has been in operation for 4½ years and has delivered 15 unit trains of Process Derived Fuel (PDF™), the low-sulfur, high-Btu solid product to five major utilities. Recent test burns have indicated that PDF™ can offer the following benifits to utility customers:

- Lower sulfur emissions
- Lower NO_x emissions
- Lower utilized fuel costs to power plants
- Long term stable fuel supply

More than three million gallons of Coal Derived Liquid (CDL™) have also been delivered to seven industrial fuel users and one steel mill blast furnace. Additionally, laboratory characteristics of CDL™ and process development efforts have indicated that CDL™ can be readily upgraded into higher value chemical feedstocks and transportation fuels.

Commercialization of the LFC™ is also progressing. Permit work for a large scale commercial ENCOAL® plant in Wyoming is now underway and domestic and international commercialization activity is in progress by TEK-KOL, a general partnership between SGI International and a Zeigler subsidiary.

The Project[1], which was cost shared by the U.S. Department of Energy under Round Three of the Clean Coal Technology program, achieved its remaining long-term objectives in the past year. These included delivery and testing of pure PDF™ in a major Eastern U.S. bituminous coal boiler, operation of the plant for long periods at greater than 90% availability and processing of an alternate source coal. Plans are to continue operation of the ENCOAL® plant for several purposes:

- testing the viability of alternate commercial scale equipment
- delivery of additional test burn quantities of products
- training operators for the commercial plant
- providing additional design data for the commercial plant

A no-cost extension to the Cooperative Agreement has been approved for six months to complete the required project close-out reports. This paper covers the historical background of the Project, describes the LFC™ process and describes the worldwide outlook for commercialization.

[1] Contract No. DE-FC21-90MC27339, ENCOAL Corporation, P. O. Box 3038, Gillette, WY 82717; Telefax (307) 682-7938

Acknowledgements

ENCOAL Corporation wishes to acknowledge the participation of D.O.E.'s project manager, Mr. Douglas M. Jewell, whose guidance and technical advice contributed to the success of the ENCOAL® project during the design, construction and operation activities over the past six years.

BACKGROUND INFORMATION

Objectives

Beneficiation of low sulfur Powder River Basin (PRB) subituminous coal is being demonstrated by the ENCOAL® Mild Coal Gasification Project using the LFC™ process. The LFC™ Technology employs a mild gasification process, that is mild pyrolysis at relatively low temperatures, to produce both liquid and solid fuels with environmentally superior properties. The demonstration plant has been in the testing and operations mode for more than 4½ years and has completed all of its original long-term goals.

ENCOAL's overall objective for the Project is to further the development of full sized commercial plants using the LFC™ Technology. In support of this overall objective, the following goals were established:

- Provide sufficient products for full-scale test burns
- Develop data for the design of future commercial plants
- Demonstrate plant and process performance

- Provide capital and operating cost data
- Support future LFC™ Technology licensing efforts

Significant progress has been made on the first four goals, and the commercialization and technology licensing efforts are in progress. This paper highlights several areas of immediate interest to potential customers and licensees. These include the status of the ENCOAL® Project, plant operating experience, plant reliability, product properties, technology development and remaining challenges. Most importantly, the status of the commercialization of the LFC™ Technology is reviewed.

General Description

ENCOAL® Corporation is a wholly owned subsidiary of Bluegrass Coal Development Company, (formerly named SMC Mining Company), which in turn is a subsidiary of Zeigler Coal Holding Company. ENCOAL® has entered into a Cooperative Agreement with the United States Department of Energy (DOE) as a participant in Round III of the Clean Coal Technology Program. Under this agreement, the DOE has shared 50% of the cost of the ENCOAL® Mild Coal Gasification Project.

The Cooperative Agreement was extended in October 1994 for an additional $18,100,000 bringing the Project total to $90,600,000 through September 17, 1996. A no-cost extension in September 1996 moved the Cooperative Agreement end date to March 17, 1997 to allow for completion of final reporting requirements. A license for the use of LFC™ Technology has been issued to ENCOAL® from the technology owner, TEK-KOL, a general partnership between SGI International of La Jolla, California and a subsidiary of Zeigler Coal Holding Company.

The ENCOAL® Project encompasses the design, construction and operation of a 1,000 TPD commercial demonstration plant and all required support facilities. The Project is located near Gillette, Wyoming at Triton Coal Company's Buckskin Mine. Existing roads, railroad, storage silos and coal handling facilities at the mine significantly reduced the need for new facilities for the Project.

A substantial amount of pilot plant testing of the LFC™ process and laboratory testing of PDF™ and CDL™ was done.[1] The pilot plant tests showed that the process was viable, predictable and controllable and could produce PDF™ and CDL™ to desired specifications. Key dates and activities in bringing the project from the pilot plant stage to its current status are:

- Through early 1987: Development of the LFC™ process by SGI.
- Mid 1987: SMC Mining Company (SMC) joined with SGI on further development.
- Mid 1988: Feasibility studies, preliminary design, economics and some detailed design work by SMC.
- June 1988: Submittal of an application to the State of Wyoming for a permit to

construct the plant - Approved July 1989.

- August 1989: ENCOAL® Project submitted to the DOE as part of Round III of the Clean Coal Technology Program - Selected in December 1989.
- September 1990: Cooperative Agreement signed. Contract awarded to The M. W. Kellogg Company for engineering, procurement and construction.
- October 1990: Ground breaking at the Buckskin Mine site.
- April 1992: Mechanical completion - commissioning begun.
- June 1992: First 24 hour run in which PDF™ and CDL™ were produced.
- November 1992: SMC Mining Company and its subsidiaries, including ENCOAL®, acquired by Zeigler.
- April 1993: ENCOAL® achieves two week continuous run.
- June 1993: Plant shut down for major modifications.
- December 1993: Plant recommissioned with added deactivation loop.
- July 1994: Completed 68 day continuous run - plant operational.
- September 1994: First unit train containing PDF™ shipped and burned successfully.
- October 1994: Two year extension and additional funding approved by DOE.
- April 1996: Shipped first unit train containing 100% PDF™.
- May 1996: Suçessfully burned PDF™ in a fully instrumented major U.S. utility boiler.

Although designed for 1000 TPD feed, the plant is currently processing 500 TPD of subituminous PRB coal due to capacity limitations in the deactivation loop. The plant produces 250 TPD of PDF™, which has the high heat content of Eastern coals but with low sulfur content, and 250 barrels/day of CDL™, which is a low sulfur industrial fuel oil. While CDL™ is different from petroleum derived oils in its aromatic hydrocarbon, nitrogen and oxygen content, it has a low viscosity at operating temperatures and is comparable in flash point and heat content.

Not a pilot plant or a "throw-away", ENCOAL's processing plant is designed to commercial standards for a life of at least 10 years. It uses commercially available equipment as much as possible, state-of-the-art computer control systems, BACT for all environmental controls to minimize releases and a simplified flowsheet to make only two products matched to existing markets. The intent is to demonstrate the core process and not make the project overly complicated or expensive.

The ENCOAL® Project has demonstrated for the first time the integrated operation of several unique process steps:

- Coal drying on a rotary grate using convective heating
- Coal devolatilization on a rotary grate using convective heating
- Hot particulate removal with cyclones
- Integral solids cooling and deactivation
- Combustors operating on low Btu gas from internal streams

- Solids stabilization for storage and shipment
- Computer control and optimization of a mild coal gasification process
- Dust suppressant on PDF™ solids

Utility test burns have shown that the fuel products can be used economically in commercial boilers and furnaces to reduce sulfur emissions significantly at utility and industrial facilities currently burning high sulfur bituminous coal or fuel oils. Ultimately, installation of commercial scale LFC™ plants should help reduce U.S. dependence on imports of foreign oil.

Process Description

Figure 1 is a simplified flow diagram of ENCOAL's application of the LFC™ Technology. The process involves heating coal under carefully controlled conditions. Nominal 3" x 0" run-of-mine (ROM) coal is conveyed from the existing Buckskin Mine to a storage silo. The coal from this silo is screened to remove oversize and undersize materials. The 2" x 1/8" sized coal is fed into a rotary grate dryer where it is heated by a hot gas stream. The residence time and temperature of the inlet gas have been selected to reduce the moisture content of the coal without initiating chemical changes. The solid bulk temperature is controlled so that no significant amounts of methane, carbon monoxide or carbon dioxide are released from the coal.

The solids from the dryer are then fed to the pyrolyzer where the temperature is further raised to about 1,000°F on another rotary grate by a hot recycle gas stream. The rate of heating of the solids and their residence time are carefully controlled, because these parameters affect the properties of both solid and liquid products. During processing in the pyrolyzer, all remaining water is removed, and a chemical reaction occurs that results in the release of volatile gaseous material. Solids exiting the pyrolyzer are quickly quenched to stop the pyrolysis reaction, then transferred to a small surge bin that feeds the vibrating fluidized bed (VFB) deactivation unit.

In the VFB unit, the partially cooled, pyrolyzed solids contact a gas stream containing a controlled amount of oxygen. Termed "oxidative deactivation," a reaction occurs at active surface sites in the particles reducing the tendency for spontaneous ignition. The heat generated by this reaction is absorbed by a fluidizing gas stream which is circulated through a cyclone to remove entrained solids and a heat exchanger before being returned by a blower to the VFB. Oxygen content in the loop is maintained by introducing the proper amount of air through a control valve. Excess gas in the loop is purged to the dryer combustor for incineration.

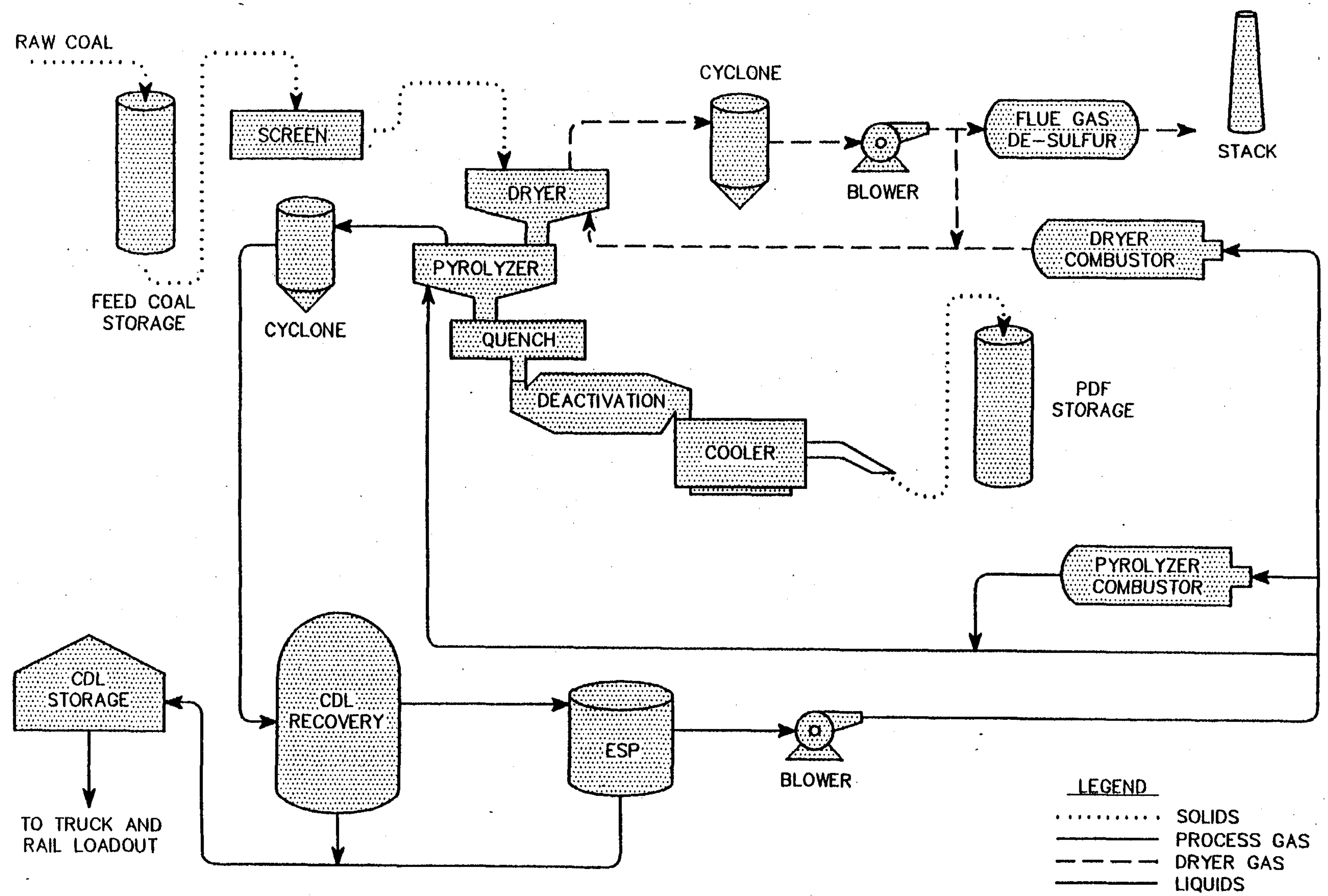

FIG. 1 : SIMPLIFIED PROCESS FLOW DIAGRAM

Following the VFB, the solids are cooled to near atmospheric temperature in an indirect rotary cooler. A controlled amount of water is added in the rotary cooler to rehydrate the PDF™ to near its ASTM equilibrium moisture content. This is also an important step in the stabilization of the PDF™. The cooled PDF™ is then transferred to a storage bin. Because the solids have little or no free surface moisture and, therefore, are likely to be dusty, a patented dust suppressant is added as PDF™ leaves the product surge bin. Patents are pending on both the oxidative deactivation and rehydration steps.

At the present time, the PDF™ is not completely stabilized with respect to oxygen and water upon leaving the plant. The PDF™ must be "finished" by a short exposure to atmospheric conditions in a layered stockpile prior to being reclaimed and shipped. In addition to atmospheric stabilized PDF™, a stable product can be made by blending run-of-plant PDF™ with either ROM coal or the atmosphere stabilized PDF™, but there is a Btu penalty. ENCOAL® has recently completed pilot-scale equipment tests that successfully perform this finishing step using process equipment. The design uses commercially available equipment to be installed just downstream of rotary cooler mentioned above, and will effectively stabilize PDF™ on a continuous basis. Installation of this equipment is currently scheduled in 1997.

The hot gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled in a quench column to stop any additional pyrolysis reactions and to condense the desired liquids. Only the CDL™ is condensed in this step; the condensation of water is avoided. Electrostatic precipitators recover any remaining liquid droplets and mists from the gas leaving the condensation unit.

Almost half of the residual gas from the liquid recovery unit is recycled directly to the pyrolyzer, while some is first burned in the pyrolyzer combustor before being blended with the recycled gas to provide heat for the mild gasification reaction. The remaining gas is burned in the dryer combustor, which converts sulfur compounds to sulfur oxides. Nitrogen oxide emissions are controlled via appropriate design of the combustor. The hot flue gas from the dryer combustor is blended with the recycled gas from the dryer to provide the heat and gas flow necessary for drying.

The unrecycled portion of the off-gas from the dryer is treated in a wet gas scrubber and a horizontal scrubber, both using a water-based sodium carbonate solution. The wet gas scrubber recovers the fine particulates that escape the dryer cyclone, and the horizontal scrubber removes most of the sulfur oxides from the flue gas. The treated gas is vented to a stack. The spent solution is discharged into a pond for evaporation. The plant has several utility systems supporting its operation. These include nitrogen, steam, natural gas, compressed air, bulk sodium carbonate and a glycol/water heating and cooling system. Figure 2 is a plot plan for the ENCOAL® Plant facilities including the Buckskin Mine rail loop that is used for shipping products.

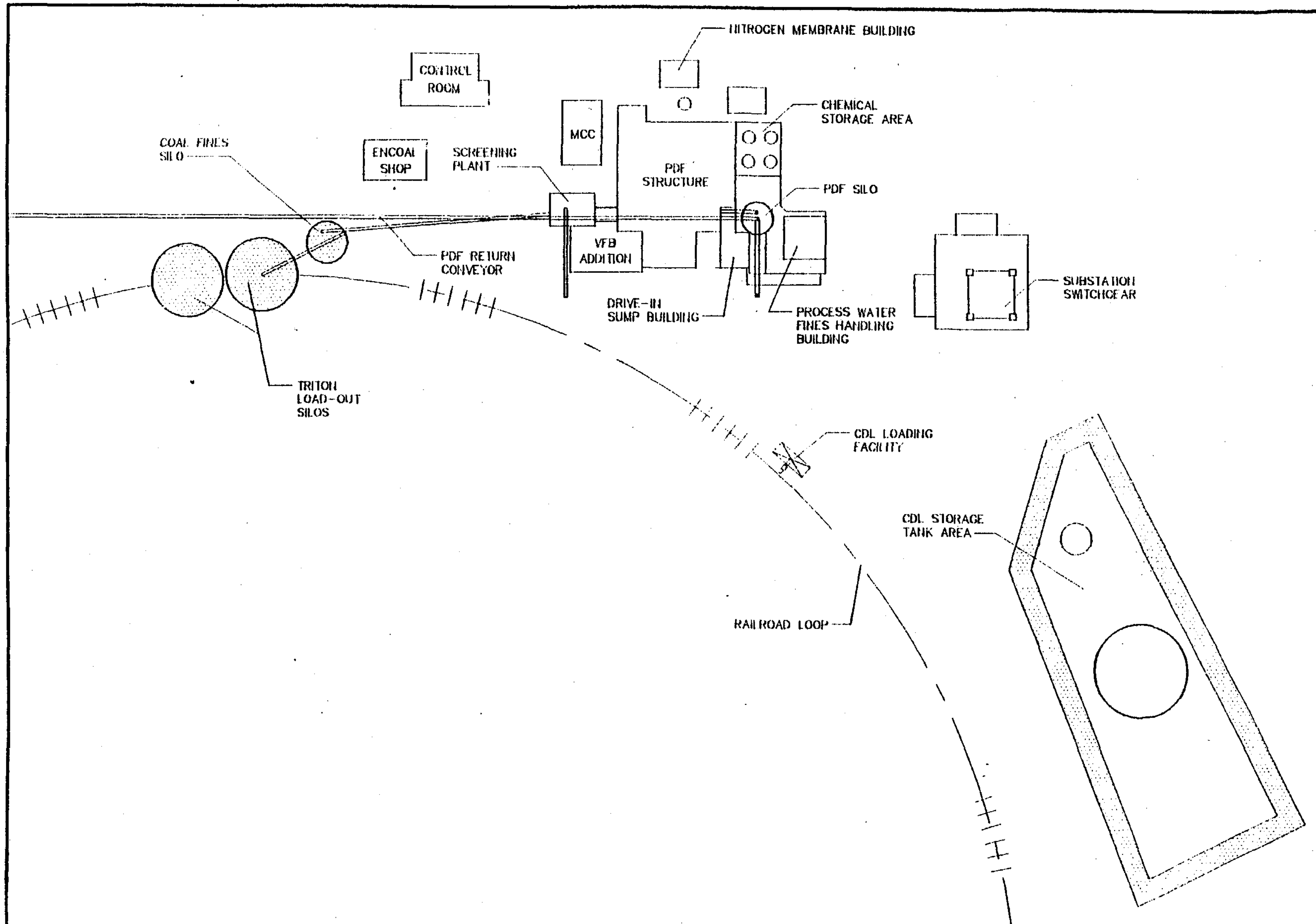

FIG. 2 : ENCOAL PROJECT PLOT PLAN

PLANT OPERATING EXPERIENCE

Production History

ENCOAL's LFC™ plant and facilities have now operated in an integrated mode producing PDF™ and CDL™ for more than 12,000 hours. The major pieces of equipment, including the large blowers, combustors, dryers, pyrolyzer and cooler have operated fare more hours overall considering hot standby and ramping operations. This equipment has been demonstrated to operate reliably. Steady state operation exceeding 90% availability has been achieved for extended periods for the entire plant, albeit at 50% of plant capacity, and the plant is currently operational. Although some testing is still ongoing, all of the plant production of PDF™ and CDL™ is for test burns. Table 1 summarizes the plant operations over the last 4½ years.

	1992	1993	1994	1995	1996*
Raw Coal Feed (Tons)	5,200	12,400	67,500	65,800	59,500
PDF™ Produced (Tons)	2,200	4,900	31,700	28,600	30,500
PDF™ Sold (Tons)	-0-	-0-	23,700	19,100	32,700
CDL™ Produced (Bbl)	2,600	6,600	28,000	31,700	27,500
Hours on Line	314	980	4,300	3,400	3,200
Average Length of Runs	2.2	8.2	25.9	38.0	N/A**

***	Through November 15, 1996**
****	Not Applicable; Plant in operation.**

Table 1. ENCOAL® Plant Performance

Product recoveries from the feed coal have varied somewhat from the original projections. In the case of PDF™, recovery has been slightly lower. This is because more fines are generated in the process than expected and they are not all currently recovered. CDL™ recovery is higher than expected by 10-15%, apparently due to a more efficient liquid recovery system than the one used in the pilot plant.

Product Test Burns

Commercialization of both the solid (PDF™) and liquid (CDL™) products from the ENCOAL® Plant took a major step forward in 1994. PDF™ was shipped in trainload quantities for the first time to utility customers. The results of these shipments demonstrated that utility and industrial users can plan for test burns of PDF™ with confidence. Use of CDL™ in the industrial low sulfur residual fuel oil market was also demonstrated.

In September 1994, ENCOAL® commenced shipment of PDF™ to utility customers via the Burlington Northern railroad. Shipments made to the first customer, the Western Farmers Electric Cooperative in Hugo, Oklahoma, started at a 15% blend level and ranged up to 30%. The upper level of these blends was determined by the heat content limit in the customer's boiler. Shipments to a second customer, Muscatine Power and Water in Muscatine, Iowa, started at 40% PDF™ and ranged up to 91%. The rail cars in this shipment were capped with a small amount of ROM Buckskin coal. Capping is one way to control loss of fine material during shipment. Because the ROM coal becomes blended with the PDF™ upon unloading, it ends up as a 91% blend.

With these first shipments, ENCOAL's goals were to demonstrate its ability to coordinate with the Buckskin Mine in loading and shipping consistent blends, to ship PDF™ with dust generation comparable to or less than ROM Buckskin coal, and to ship PDF™ blends that are stable with respect to self heating. Furthermore, ENCOAL® intended to demonstrate that PDF™ could be transported and delivered to customers using regular commercial equipment. With respect to utilization, the goal for these shipments was for customers to burn trial amounts (½ unit train minimum) of PDF™ blends with minimal adjustment of equipment. These goals have all been met as reported in a more detailed test burn report[2].

In 1995, ENCOAL® shipped two additional trains to Muscatine and initiated shipments to a third customer, Omaha Public Power District (OPPD) in Omaha, Nebraska. Three unit trains were shipped to OPPD containing approximately 25% PDF™. This customer has been burning PRB coal in a boiler designed for bituminous coal for some time, and the increased heat content of the PDF™ blends helped increase plant output.

In 1996, ENCOAL® began shipping unit trains containing 100% PDF™ for the first time. As of the end of October 1996, two 100% PDF™ unit trains have been delivered to two separate utilities for test burns. The first was burned in Indiana-Kentucky Electric Cooperative's (IKEC) Clifty Creek Station, which is jointly owned by American Electric Power (AEP). The PDF™ was blended with Ohio high sulfur coal at the utility and burned in the Babcock & Wilcox open-path, slag-tap boiler with full instrumentation. Blends tested ranged between 70 and 90% PDF™, and burn results indicated that even with one pulverizer out of service, the unit capacity was increased significantly relative to the base blend. More importantly, there was at least a 20% NO_x reduction due to a more stable flame. Completion of this test burn achieved a major DOE Cooperative Agreement Milestone of testing PDF™ at a major U.S. utility. This goal is discussed further in an independent third party test burn report.[6] The remaining 100% PDF™ unit train was sent to Union Electric near St. Louis, MO. PDF™ shipments through October 1996 are documented in Table 2.

Coincident with PDF™ shipments was a broadening of the customer base for the liquid CDL™ product. To date, ENCOAL® has shipped CDL™ to eight different customers. With the exception of one steel mill injectant test, the CDL™ has been blended and used as fuel oil. CDL™ has proven to be acceptable in the fuel oil market through these test burns.[2] However, since the price of fuel oil is currently very low, upgrading of CDL™ into more profitable products has been studied. Initial testing of CDL™ has shown that extraction of higher value products is both technically and economically feasible. Detailed characterization of the CDL™ and evaluation of several upgrading processes have already been completed. Other processes continue to be studied, but in general, upgrading of CDL™ will yield specialty chemical feedstocks and transportation fuels. Further work on upgrading is planned in 1997. Table 3 summarizes the CDL™ tank car shipments thus far.

DATE LOADED	CUSTOMER	BLEND (%PDF™)	TONS SHIPPED			HEAT CONTENT (Btu/lb)
			PDF™	COAL	BLEND	
09/17/94	W. Farmers	14.4	922	5,448	6,370	8,760
09/24/94	W. Farmers	21.2	1,080	4,020	5,100	8,910
10/01/94	W. Farmers	25.1	1,508	4,493	6,001	8,940
10/10/94	W. Farmers	31.9	1,603	3,241	5,024	9,310
10/24/94	W. Farmers	24.0	2,665	8,426	11,091	9,060
11/23/94	Muscatine	39.0	1,957	3,122	5,079	9,630
11/29/94	Muscatine	66.6	3,423	1,713	5,136	9,670
12/13/94	Muscatine	90.7	10,576	1,082	11,658	10,000
04/23/95	Muscatine	33.0	3,979	8,094	12,073	9,127
05/05/95	Omaha PPD	24.4	2,711	8,412	11,123	8,940
05/11/95	Omaha PPD	24.0	2,669	8,464	11,133	8,939
05/13/95	Omaha PPD	26.0	2,952	8,398	11,350	8,854
08/16/95	Muscatine	94.0	6,750	434	7,184	9,873
04/25/96	IKEC (AEP)	100.0	9,739	0	9,739	10,682
07/22/96	Union Electric	100.0	11,260	0	11,260	10,450

Table 2. Summary of Trains Shipped Containing PDF™ *(Through 10/31/96)*

CUSTOMER	# OF CARS	DESTINATION	USE
Dakota Gas	87	Beulah, ND	Industrial Boiler
Texpar	3	Milwaukee, WI	Small Boilers
3 M Company	14	Hutchinson, MN	Industrial Boiler
Kiesel	2	St. Louis, MO	Blend W/ #6 Oil
US Steel	2	Chicago, IL	Steel Mill Blast Furnace
Michigan Marine	18	Detroit, MI	Blend W/ #6 Oil
M&S Petroleum	40	Lake Charles, LA	Fuel Oil Blend
Baka Energy INC.	6	Houston, TX	Fuel Oil Blend

Table 3. Summary Of CDL™ Tank Car Shipments ***(Through 11/15/96)***

CHALLENGES

A detailed review of equipment and plant modifications through July 1995 has been presented[1,3,5]. Table 4 summarizes the major challenges that have been overcome and the solutions implemented.

AREA OF PLANT	DEFINITION OF PROBLEM	SOLUTION
Electrostatic Precipitators	Insulator Failures	Modified Insulators, Improved Temperature Control
Material Handling	Plugging and Spillage	Modified S-belts & Chutes
PDF™ Quenching and Steam Condenser	Oil and Coal Dust, Too Small	Added Scrubber, Added 2 Larger Exchangers
Dryer and Pyrolyzer	Sand Seal Failures	Replaced With Water Seals
Combustors	Unstable Operation	Revised Control System
Pumps and Blowers	Sizing Problems, Mostly Too Small	Replaced With Larger Equipment
Changing Process Variables	Initial Plant Design Parameters Were Off	Adjusted Operating Set Points
PDF™ Dust Collection	Dusty Conditions On Product Side of Plant - No Scrubbers	Added Two Wet Scrubbers
PDF™ Deactivation	Could Not Produce Stable PDF™ In Original Equipment	Added VFB Deactivation Loop Equipment
Process Water System	Accumulation Of Oily Fines In Process Equipment	Installed Clarifier, Floc & Vacuum Filter
Cyclone Fines Handling	Loss Of Excessive Amounts Of PDF™ In Cyclone Fines, Labor Intensive Clean-up	Recovered VFB Deactivation Fines Into PDF™ Product, Reduced Handling System
VFB Drag Conveyors	Excessive Wear and Maintenance Intensive	Redesigned High Wear Points, Modified Discharges To Reduce Plugging
Plant Operability And Maintenance	Difficult Access, Labor Intensive Clean-up, Inflexible To Operate	Piping Revisions, Access Platforms And Doors, Relocate Valves

Table 4. Summary Of Plant Modifications

Still to be solved are several challenges involving plant capacity, PDF™ deactivation, and removal of coal fines from the CDL™. In addition, CDL™ upgrading even on the small scale of the ENCOAL® plant, appears to be economically attractive as well as something that needs to be tested before application in a large commercial plant. Data collection and designs are complete for the plant capacity improvements and PDF™ finishing projects, and work on the other projects scheduled for next year is in progress.

PDF™ Deactivation

Total product deactivation remains a key challenge. At the present time, the PDF™ is not completely stabilized in the plant but has to be "finished" by a short exposure to atmospheric conditions external to the plant. ENCOAL® has recently completed pilot-scale equipment tests that successfully performed this finishing step using process equipment. The design uses commercially available equipment to be installed just downstream of the rotary cooler, and will effectively stabilize PDF™ on a continuous basis. Installation of this equipment is currently scheduled in 1997.

Plant Capacity

One known bottleneck remains that prevents attainment of full design capacity of 1,000 TPD. The VFB loop is the limiting factor, since it was designed for 50% of plant capacity. A second unit was planned once the effectiveness of the PDF™ deactivation process was demonstrated. After the PDF™ finishing equipment mentioned above is installed, the addition of the second VFB may be required to reach full plant capacity.

CDL™ Upgrading

The ENCOAL® plant was intentionally designed to capture a single, wide-boiling-range liquid product, CDL™ , as opposed to making multiple liquid fractions. This was done to simplify the operation, lower the capital cost and reduce the risk associated with the added complication of liquid separations. It was determined that this would be evaluated after the basic LFC™ Technology had been demonstrated. Attention has now been turned to CDL™ upgrading since the plant has moved into a production mode.

Some preliminary feasibility and design work has indicated that upgrading of the CDL™ both in the ENCOAL® plant and on a commercial scale makes economic sense; indeed it may be required to produce products that can be sold in quantity in existing markets. The M. W. Kellogg Company developed a design and cost estimate for modifying the existing plant for upgrading CDL™ in 1995. The design used information from laboratory studies and a complete CDL™ chemical characterization to develop the a workable process.

The basic concept is to produce three commercially viable streams; (1) a transportation grade fuel feedstock that would include most of the aliphatic compounds present in CDL™, (2) a tar acid fraction that would include the cresylic acids, phenols and light aromatics and (3) a heavy residual bottom that would be suitable as anode binder pitch. This concept is currently being considered for implementation in the ENCOAL® plant to demonstrate its potential for commercial- sized LFC™ plants as well as to enhance the economics of continued operation of the existing plant.

CDL™ Solids Removal

The pyrolyzer loop cyclone was specifically designed to remove the coal fines from the gas stream prior to recovery of the CDL™ in the quench tower and ESP's. However, the cyclone does not effectively remove all of the fines, and the CDL™ consequently has 2 to 4% entrained solids. All CDL™ upgrading schemes identified to date have indicated that the fines in the CDL™ are undesirable. The fines must therefore be removed or reduced in quantity in order to meet customer requirements for any sale other than fuel oil. Testing of various methods of solid/liquid separation techniques is ongoing, and installation of a system at the ENCOAL® plant is scheduled in 1997.

PDF™ Properties

After 4½ years of operation and production of 97,900 tons of PDF™, the properties of PDF™ that can be produced in the plant are fairly well defined. The variables that are controllable to some extent in the process are the heat content, volatiles, and moisture. The components dictated by the composition of the feed coal are ash, sulfur, size consist, and hardness. The LFC™ process has little impact on the ash composition or ash fusion temperature. Test data have been presented in previous reports[3] that show the variability of the PDF™ with process conditions. Table 5 represents the averages of the PDF™ that are currently being made at the ENCOAL® plant.

PROXIMATE ANALYSIS	PLANT RUN	LAYDOWN BLEND	TARGET
Heat Content (Btu/lb)	11,112	10,682	11,400 - 11,600
Moisture (%)	9.81	10.1	8 - 9
Ash (%)	7.56	7.9	6 - 9
Volatile Matter	25.93	26.7	21 - 24
Fixed Carbon (%)	56.70	54.8	57 - 60
Sulfur (%)	0.41	0.52	0.51 Maximum
OTHER			
Hardgrove Grindability	47	43	45 - 50
#Sulfur/MMBtu	0.37	0.40	0.45 Maximum
#SO_2/MMBtu	0.74	0.81	0.90 Maximum
Ash Mineral Analysis	Same as coal	Same as coal	Same as coal
Ash Fusion Temperature	2220°F	2220°F	2220°F

Table 5. Average Representative Properties of PDF™

CDL™ Properties

Like PDF™, the properties of CDL™ are influenced by the pyrolyzer operation. However, the properties of CDL™ are also influenced by operation of equipment in the pyrolysis gas loop, including the pyrolyzer cyclone, the quench tower and the electrostatic precipitators. These directly affect the amount of water and sediment in the CDL™. Again, a significant amount of data has been presented in previous reports[3], so only the following summary table is presented here. A significant amount of work has been done on the detailed chemical characterization of CDL™ for the upgrading project discussed above. This work is ongoing and will be the subject of future reports.

	CDL™	Low Sulfur Fuel Oil
API Gravity (°)	1.3 - 3.2	5
Sulfur (%)	0.3 - 0.5	0.8
Nitrogen (%)	0.6	0.3
Oxygen (%)	6.2	0.6
Viscosity @ 122°F (cs)	280	420
Pour Point (°F)	66 - 90	50
Flash Point (°F)	165	150
MBtu/gal	140	150
Water (wt %)	0.5	<1
Solids (wt %)	2 - 4	<1
Ash (wt %)	0.2 - 0.4	<1

Table 6. Average CDL™ Quality

COMMERCIALIZATION

ENCOAL® Corporation has a sublicense for the LFC™ Technology from the TEK-KOL Partnership. The Partnership, owned by SGI International and a subsidiary of Zeigler Coal Holding Company, is responsible for the commercialization and licensing of the LFC™ Technology and thus is carrying out ENCOAL's obligation under the Cooperative Agreement. Under the TEK-KOL Partnership Agreement, SGI International is designated as the Licensing Contractor responsible for licensing and promoting the LFC™ Technology. Zeigler is the administrative partner responsible for preparation of lease agreements and contracts.

Commercialization of the LFC™ Technology consists of marketing the products, PDF™ and CDL™, to interested consumers at prices that will support the construction of commercial plants. Concurrently, the LFC™ Technology must be licensed to the prospective plant owners. These may or may not be the same as the consumers of the products. The technology and product marketing activities are closely interwoven and are carried out by both TEK-KOL partners. For the most part, ENCOAL® carries out all Zeigler partnership activities.

In order to determine the viability of potential LFC™ plants, TEK-KOL has already completed several detailed commercial plant feasibility studies (called Phase II studies as described previously [3]). These studies include plant design, layout, capital estimates, market assessment for co-products, operating cost assessments, and overall financial evaluation. Operation of the ENCOAL® plant provided the basis for estimating operating cost and commencing product market development, and unlike most upgrading projects, full-scale shipment and test burns made possible by the near-commercial size of the ENCOAL® plant has provided actual market information for the basis of these studies. Operating experience of the ENCOAL® facility was also used for the design basis and capital estimates. In February 1996, TEK-KOL and Mitsubishi Heavy Industries (MHI) signed an agreement to jointly produce Design and Engineering Cost Estimates for commercial LFC™ plants. This arrangement combines the scientific, engineering, and operating experience of the TEK-KOL staff with the engineering and design experience of MHI to produce a comprehensive study. To date, three detailed LFC™ Phase II studies have been completed by the TEK-KOL/MHI team. These studies are discussed below.

Domestic Markets

The most promising markets for the application of the LFC™ Technology in the U.S. are the subituminous coal deposits in the Powder River Basin. Close behind are the subituminous reserves in Alaska's Beluga field, lignites in North Dakota, followed by Texas lignites near San Antonio. Testing on all of these coals has been conducted in the TEK-KOL Development Center (Center) Sample Production Unit (SPU) with favorable results.

Application of the LFC™ Technology to swelling or agglomerating coals is not feasible at this time, so most of the central and eastern U.S. coals are not candidates. Removal of sulfur by the LFC™ process has proven to be significant, especially when the sulfur form is highly organic, but these bituminous coals would still be too high in sulfur after processing to meet the amended clean air act requirements. Central and eastern U.S. coals are also more costly to mine than western subituminous coal, leaving less margin for upgrading. For these reasons, central and eastern U.S. coals do not appear to be promising candidates for LFC™ processing.

Powder River Basin. A large portion of the extensive U.S. coal reserves lie in the Powder River Basin in Montana and Wyoming. Subituminous and low in sulfur, this coal is ideal for processing via the LFC™ Technology. That is a major reason the ENCOAL® plant was located near Gillette. The southern end of the PRB in Wyoming is of special interest because the sulfur and ash are especially low. Here the PDF™ product may have an increased value for metallurgical applications or as a super compliance blending material.

Overall, the PRB has the lowest mining costs in the U.S. and, being a long distance from the major utility markets, has the highest transportation costs. This combination yields a large differential value between the raw material cost and the delivered cost. The high incremental value, a well developed transportation infrastructure, qualified, available labor force and a large number of operating mines mean that the opportunities for installation of commercial LFC™ plants are very good for the PRB.

A Phase II technical and economic feasibility study was completed on one potential PRB site in 1996. This study was for a commercial-size LFC™ plant to be located at Triton Coal Company's North Rochelle Mine site. The site includes three 5,500 ton feed coal/day LFC™ modules, a 240 MW cogeneration plant, and CDL™ upgrading facilities integrated with the mine-site infrastructure. Results of the study indicated that the project has a financible rate of return *(>15%)* without any government subsidies, price supports, or tax credits. In other words, the LFC™ products compete in current markets at current prices. However, the aid of government tax incentives would help offset the financial risk associated with a project of this magnitude. This study was recently refined in order to confirm the project economics, and to assemble design information for submittal of permit applications required by the State of Wyoming to allow construction to begin. An air permit application was submitted in November 1996 followed by Land Quality and Industrial Siting Permits around the end of the year.

Alaska. There are two promising areas in Alaska for the installation of commercial LFC™ plants, namely the Beluga fields and the Healy deposits. Both areas have extensive reserves, are largely subituminous in nature and have low ash and sulfur. The Beluga coal is very near the Cook Inlet with the possibility of a deep water port for exports. However there is essentially no infrastructure to produce these reserves and this would be a costly venture. Current owners of the three main lease areas have not been able to attract buyers of the coal in the current market. Mine development would have to be included in any LFC™ plant venture.

At Healy, there is an existing producing mine and coal is shipped by rail to the coast for export. The Healy coal has been tested at the Center with good results. However the cost of mining is fairly high, transportation costs are high and there is no local market. The PDF™ and CDL™ from a project in this area may have difficulty competing with other locations.

North Dakota Lignite. Significant reserves of lignites are present in the Williston Basin of North Dakota and tests on some of them indicate good potential for LFC™ processing. Lab tests have indicated that good quality PDF™ and acceptable yields of CDL™ are produced using LFC™ Technology. Most recently, these coals have been further tested at the Center for mechanical strength during processing, also with positive results.

Overall, the economics of commercial LFC™ plants for the North Dakota lignites appear attractive. The coal seams are relatively thick and the sulfur and ash content are low, although not as low as the PRB. However, North Dakota is closer to some important markets. This coal is being considered for an alternate coal test in the ENCOAL® plant.

Texas Lignite. Numerous tests on Texas lignites have been conducted at the Center. With some lignites, the PDF™ quality and CDL™ recoveries have proven to be acceptable. However, other Texas lignites, although extensively available, are not considered to be viable candidates because of poor coal quality. Coal quality combined with proximity of the existing lignite mines near power plants designed to burn ROM material, makes the application of an LFC™ plant unlikely in the near future. Interest in exporting upgraded Texas lignites into other markets, or applying an LFC™ facility to replace an existing coal drying process would be two most likely scenarios for a Texas based facility.

<u>International Markets</u>

TEK-KOL is also actively pursuing international opportunities for applying the LFC™ Technology. Primary areas of immediate interest are in China, Indonesia, and Russia. These areas have been identified by TEK-KOL as the most likely to develop in the near future, and accomplishments in these areas are discussed in more detail below. Other potential international applications for the

LFC™ Technology *(such as the Pacific Rim, Southeast Asia, India and Pakistan, Eastern Europe, and Australia)* that have previously been discussed[5], have been identified by TEK-KOL as longer range development projects. For this reason, progress in these areas is not discussed in this paper.

China. China is the largest producer as well as the largest consumer of coal in the world. Over a third of the coal production occurs in the three northern provinces of Shanxi, Shaanxi and Inner Mongolia. However, due to significant transportation infrastructure problems, it is not always possible to move the coal within China to meet local needs. As a result of the extremely high economic growth in the southern and eastern coastal regions of China accompanied by a parallel demand for new electrical power, there are predictions that China may require imports of coal in the range of 10-50 million tons per year by 2010. Furthermore, the predictable result of burning such prodigious quantities of coal, much of it high in sulfur, is an environmental problem of such magnitude that it is a major concern not only of the Chinese government but also for the governments of neighboring countries and, indeed, the world.

For these reasons, China is viewed as one of the prime candidates for application of the LFC™ Technology. The LFC™ Technology offers China the opportunity:

- to more efficiently and effectively employ its vast resources of coal
- to conserve scarce and valuable railroad assets as a result of the moisture reduction aspect of the LFC™ Technology
- to vastly expand its exports into the world steam coal and metalurgical markets and, thereby, generate much needed foreign revenue
- to augment valuable and increasingly scarce petroleum assets through the production of CDL™
- to reduce the extremely severe pollution problems associated with burning high sulfur coal

The LFC™ Technology has been actively promoted in China for several years with the Ministry of Coal Industry (MOCI) and officials of regional coal mine administrations by explaining the value of employing the LFC™ Technology and developing potential commercial plant projects. Although China has huge quantities of bituminous and anthracite coal, it also has great reserves of subituminous and lignite coals that are ideal candidates for upgrading using the LFC™ Technology. MOCI expressed keen interest in the advantage to China offered by the LFC™ Technology and representatives of SGI International have visited various mining areas in China that could be potential sites for LFC™ projects.

Indonesia. Approximately 93% of Indonesia's reported 36+ billion metric tons of reserves are in the form of subituminous and lignite coal. Significantly, though, this accounts for over 97% of the identified recoverable reserves in all of the Asian countries. These reserves are split approximately 70% on the island of Sumatra and 30% on the island of Kalimantan. In fact, the Indonesian reserves have not been definitively studied yet and there exists some question as to the full extent of the identified and hypothetical reserves. On a positive note, the vast majority of the mines are open-cut operations enjoying thick seams and are mostly located near the coast or close to a navigable river, facilitating ready access to international as well as domestic markets.

Indonesia's rapid economic growth during the past decade has fueled an increase in the demand for electrical power that has grown at 11-15% per year. Furthermore, although Indonesia has been a major exporter of oil, as a result of the surging domestic growth and the limited oil reserves, it is predicted to become a net importer of petroleum by the year 2000. While a significant portion of the coal production will be destined to feed the growing domestic electrical power and industrial needs, Indonesia also requires the foreign exchange credits which will result from increasing the export market. Consequently, it is under strong pressure to better exploit its vast reserves of subituminous and lignite coal.

Toward this end, work has been ongoing in Indonesia for over five years to promote the advantages of the LFC™ Process in answering many of Indonesia's needs. The coal industry is dominated by P.T. Tambang Batubara Bukit Asam (PTBA), the state coal mining corporation which operates under the Ministry of Mines and Energy. The structure of the industry includes the state-owned mines operated by PTBA, national companies contracted by PTBA under coal concession contract agreements, private domestic companies operating under mining concessions issued by PTBA and a few local area coal cooperatives.

Employment of the LFC™ process to upgrade low-rank coal would permit Indonesia, which is closer to Japan, South Korea, Taiwan and Hong Kong, to become very competitive in the steam coal markets. A Phase I study on some thirteen different samples indicated that several of the coals of the Tanjung Enim region of South Sumatra were good-to-excellent candidates for upgrading using the LFC™ process. Indonesia, which is short on invesment capital, submitted a request to the U.S. Trade and Development Agency (TDA) for a grant for a Phase II study. This grant was approved by the TDA, and a Phase II study was completed in September 1996. This project included one to three LFC™ modules with a range of 40 to 100 MW of cogeneration, along with CDL™ upgrading facilities, transportation infrastructure, and living quarters. The study did not include the development and operation of the adjacent mine. Economics of the PTBA study were encouraging, and efforts to sign a contract with PTBA to conduct a more detailed investigation are underway.

Additionally, one Phase II study on a site adjacent to a P.T. Berau Lati Mine in East Kalimantan was completed. The study included a single LFC™ module, 40MW cogeneration plant, and a CDL™ upgrading facility that was located adjacent to the existing mine river shipping station. This one module LFC™ plant case resulted in moderate economics due to its limited throughput and relatively high operating cost. The Lati Mine coal was determined to be exceptional candidate for upgrading using the LFC™ Technology. However, local infrastructure issues, including the price of feed coal, must be resolved before the situation becomes favorable for a profitable development of a commercial LFC™ project.

Opportunities continue to be pursued in Indonesia from Aceh at the northern tip of Sumatra to lignite mines in Sulawesi. The value of the LFC™ Technology to Indonesia parallels very closely the advantages mentioned for China. Where China enjoys huge production capabilities in all forms of coal, it is especially important to Indonesia to upgrade the vast reserves of subituminous and lignite coals in order to participate effectively in the world steam coal market. Much of Indonesian coal is already naturally low in sulfur, so the resulting PDF™ is particularly attractive to markets in Japan. Work is continuing with MHI and other Japanese firms interested in cooperating in the development of projects in Indonesia and the rest of Asia.

Russia. Russia accounts for about 60% of the coal production of the former Soviet Union with almost all the rest coming from Ukraine and Kazakhstan. The increasing importance of coal to the fuel and energy balance of Russia must be viewed with the understanding of the major drop in crude oil production and decreased growth rate of gas production. Representatives of the Russian coal group ROSUGOL and the Kemerovo Coal Certification Center in south central Siberia have been evaluating a project using the LFC™ Technology in the Kemerovo region. Following a visit to SGI's offices in La Jolla, California and the ENCOAL® Plant in Gillette, Wyoming, Russian representatives signed a letter of intent to proceed with Phase I and Phase II studies for an LFC™ project. The Russian delegation was particularly excited about the value added by the production of CDL™ which is so important in view of reduced oil production. The Phase I study was completed in late 1995, and indicated that the coals tested were suitable for LFC™ upgrading. Work on a Phase II study is expected to begin in 1997 pending Russian agreement to proceed. If successful, this Russian endeavor could be the first of many projects in this country with huge potential reserves.

Long Term Impact Of LFC™ Commercialization

The LFC™ Technology is uniquely positioned in the world coal conversion and upgrading market to impact two widely used fossil energy forms, namely solids and liquids. Many technologies have successfully demonstrated the conversion of coal to synthetic gases which are in turn used as a clean energy source. Others have demonstrated the manufacture of hydrocarbon liquids from these synthetic gases to serve as chemical or transportation fuel feedstocks. Still other technologies have demonstrated the technical feasibility of direct conversion of coal to hydrocarbon liquids. Although not truly coal conversion, coal upgrading by removal of undesirable constituents like water, sulfur and ash has also been extensively demonstrated on a commercial scale by numerous technologies. The LFC™ Technology alone produces both an upgraded solid product and hydrocarbon liquids.

Economic conditions for typical commercial coal conversion and upgrading projects are generally absent without some form of political intervention, such as price supports, grants, subsidies or artificial market constraints. While tax credits would be helpful on the first LFC™ plant to offset risks, commercial LFC™ plants can compete in today's markets at today's prices with attractive rates of return. Therefore, countries with significant indigenous coal reserves (like the U.S.) or countries with significant investment or material supply interests (like Japan), should be able to use the LFC™ Technology to further economic growth.

Of course there are practical limits to the application of the LFC™ Technology. Some of the criteria for successful commercial projects can be generally stated as:

- Significant coal reserves - greater than 150 million ton block for a 3 module LFC™ plant
- Non caking, non agglomerating coal - like most low rank coals
- Low mining costs
- Low ash and inorganic sulfur content
- Located near navigable water or other reasonably priced accessible form of transportation

- Favorable political climate
- Markets for products for products at acceptable prices

There are many coal deposits in the world today which meet all of these criteria.

Consumers of solid and liquid energy products, which more and more is a world-wide market, should see significant advantages in the products from commercial LFC™ plants. The benefits for the consumer can be summarized as:

- Reduced dependance on petroleum based liquid products and the widely variable prices in that market
- Reduced environmental impact from the burning of PDF™ and CDL™ in the form of lower SO_x and NO_x as demonstrated by test burns. LFC™ plants are also very environmentally benign
- Lower fuel costs for power plants and industrial boilers on a fully utilized basis
- Long term, stable fuel supply
- Unique characteristics for metallurgical and ferroally markets
- For consumers with coal reserves, incresed use of domestic resources

Given the widespread availability of qualified candidate coals and the numerous benefits that accrue to consumers of the LFC™ products, commercialization of the LFC™ Technology should be able to make a major long term positive impact on the world energy picture. TEK-KOL and the commercial LFC™ plant development team are actively pursuing these opportunities.

FUTURE WORK

The next step in the Project is to continue to deliver high quality, pure PDF™ to utility customers and potential steel industry and ferroally users for test burns. These deliveries will aid in the development of future PDF™ markets and help secure product contracts for commercial LFC™ plants. Work on installing PDF™ finishing equipment, plant capacity upgrades, and CDL™ solids removal systems are expected in 1997. Installation and operation of these systems will provide the operation data and experience important for the final design and construction of a commercial LFC™ facility.

The goal is to maintain better than 90% availability on the plant this year and complete any remaining major plant modifications by the end of 1997. Efforts to commercialize the LFC™ Technology will continue both at home and abroad. The evaluation of CDL™ upgrading will also continue and a decision made about proceeding with an ENCOAL® plant modification.

CONCLUSIONS

The ENCOAL® Project has completed most of its goals. Essentially all the major Cooperative Agreement Milestones have been met, and final reporting requirements will be completed in early 1997. The debugging phase is complete and steady state operation has been achieved. The LFC™

Technology is essentially demonstrated and marketable PDF™ and CDL™ are being produced.

Significant quantities of both products have been shipped and successfully used by customers, thus proving them to be acceptable fuel sources in today's markets. Efforts to commercialize the LFC™ Technology, both domestically and internationally, are in progress.

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GLOSSARY

AEP	American Electric Power
AS	American Society of Testing Methods
°API	American Petroleum Institute measure of oil density
BACT	Best Available Control Technology
Btu	British Thermal Unit
Center	TEK-KOL Development Center in Perrysburg, Ohio
CDL™	Coal Derived Liquid
CO	Carbon Monoxide
CH_4	Methane
DOE	U. S. Department of Energy
ENCOAL®	ENCOAL® Corporation, a wholly owned subsidiary of Bluegrass Coal Development Co., which is a wholly owned subsidiary of Zeigler Coal Holding Co.
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitators
IKEC	Indiana-Kentucky Electric Cooperative
lb.	Pound
LFC™	Liquid From Coal
MHI	Mitsubishi Heavy Industries, Hiroshima, Japan
MMBtu	Million British Thermal Units
MOCI	Ministry of Coal Industry
MT	Metric Tonnes
N/A	Not Available
NO_x	Nitrogen Oxides
OPPD	Omaha Public Power District, Omaha, Nebraska
OSHA	Occupational Safety & Health Administration
PDF™	Process Derived Fuel
PRB	Powder River Basin
ROM	Run-of-mine
S-Belt	Vertical conveyor with flexible sidewalls and rubber buckets
SGI	SGI International, La Jolla, CA
SMC	SMC Mining Company, Evansville, IN *(name changed to Bluegrass Coal Development Co.)*
SO_2	Sulfur Dioxide
SPU	Sample Production Unit, TEK-KOL Development Center
Std. Dev.	Standard Deviation
TEK-KOL	A general partnership between SGI International and a subsidiary of Zeigler Coal Holding Company
TGA	Thermogravimetric analysis, procedure for analyzing coal and PDF™
TPD	Tons Per Day
vs.	Versus
WP&L	Wisconsin Power and Light
wt.	Weight
#	Pound