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Coal Gasification, Power Generation, and Product Market Study

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EXECUTIVE SUMMARY

This Western Research Institute (WRI) project was part of a WRI Energy Resource Utilization Program to stimulate pilot-scale improved technologies projects to add value to coal resources in the Rocky Mountain region. The intent of this program is to assess the application potential of emerging technologies to western resources.

The focus of this project is on a coal resource near the Wyoming/Colorado border, in Colorado. Energy Fuels Corporation/Kerr Coal Company operates a coal mine in Jackson County, Colorado. The coal produces 10,500 Btu/lb and has very low sulfur and ash contents. Kerr Coal Company is seeking advanced technology for alternate uses for this coal. The results will have application to coal production throughout Wyoming and the region. This project was to have included a significant cost-share from the Kerr Coal Company ownership for a market survey of potential products and technical alternatives to be studied in the Rocky Mountain Region.

The Energy Fuels Corporation/Kerr Coal Company and WRI originally proposed this work on a cost reimbursable basis. The total cost of the project was priced at $117,035. The Kerr Coal Company had scheduled at least $60,000.00 to be spent on market research for the project that never developed because of product market changes for the company. WRI and Kerr explored potential markets and new technologies for this resource.

The first phase of this project as a preliminary study had studied fuel and nonfuel technical alternatives. Through related projects conducted at WRI, resource utilization was studied to find high-value materials that can be targeted for fuel and nonfuel use and eventually include other low-sulfur coals in the Rocky Mountain region.

The six-month project work was spread over about a three-year period to observe, measure, and confirm over time any trends in technology development that would lead to economic benefits in northern Colorado and southern Wyoming from coal gasification and power generation.

INTRODUCTION

Background

Western Research Institute (WRI) has characterized coal resources and performed concept and process investigations. The work performed under past contracts included projects of physical simulation of processes dealing with advanced fuels preparation, refining, coal production, coal process emissions monitoring, and extraction activities. This project was meant to be a study and precursor to larger projects that could be supported by Wyoming industries, other western state coal producers, and the U.S. Department of Energy (DOE) under WRI's JSR program. The goal of WRI is technology development that will sustain fossil energy production in this part of the West. In projects under previous contracts, WRI has focused on developing an economically and environmentally viable process to convert coal to gas and a suite of products, including high-Btu gas, high-aromatic condensables, and char (Cha et al. 1988). WRI's experience in underground coal gasification (UCG) and advanced exploratory research areas, has enabled WRI to realistically measure pilot process and environmental performance as well as perform the monitoring tasks for the production of added-value gas and other products such as high-aromatic condensables and char.

Most Midwestern electricity is generated with coal that costs about $20/ton. The average price of coal produced in southwestern Wyoming is approximately $18-21 per ton. This includes coals from the Hanna, Green River, and Hams Fork coal fields in Wyoming, as well as the North Park Coal Region in Colorado. The average price of coal produced in the northeastern portion of the state is approximately $6 per ton (Powder River Coal Field). However, sales of low-priced coal (FOB mine price less than $5) have increased every year since 1985. To continue to maintain a market share, these Rocky Mountain region coals should be examined in light of technology to add value and/or improve combustion characteristics.

Any new technology to add value or improve combustion in this region must also compete with projections of regional energy costs over the next 10 to 15 years. The average wholesale rate to the TRI-State G&T system of 34 rural utilities (18 in Colorado, six in Nebraska, and 10 in Wyoming) is 4.0 cents per kilowatt-hour at this time. Corporate strategy is to lower cost of coals to the generation and transmission companies so they can lower costs from $1.25 per million Btu to $.87 per million Btu.

One candidate coal resource in the region is located in a pristine area of northern Colorado south of the Wyoming border, 92 miles by rail from Laramie, Wyoming. Energy Fuels Corporation/Kerr Coal Company operates a coal mine in this resource in Jackson County, Colorado. The coal produces 10,500 Btu/lb and has very low sulfur and ash contents. The coal is expensive to mine ($20/ton) because it is located in a steeply dipping syncline. Transportation of the coal has been by rail from the mine to Laramie, Wyoming, where it is then distributed to market on the Union Pacific Railroad. Some of this Kerr coal was consumed for cement production and commercial heating in Laramie. In the event rail transportation is not available in the future, Kerr Coal Company was seeking advanced technology for alternate uses/products for the coal.

Continuing operation of the Wyoming Colorado (WYCO) Railroad was highly uncertain as in December 1993, when Walden County Commissioners petitioned the State of Colorado for exemption with the Interstate Commerce Commission to abandon the railroad from Walden to the Wyoming State Line. In 1995, the railroad was abandoned.

The project also included the preliminary assessment of the steeply dipping Kerr resource for coal gasification and power generation technologies. Eventually, high-value material production could be tested for these low-sulfur western coals. WRI is exploring technical development involving mine-site power generation and coal upgrading that may prove commercially feasible.

Technical Approach

WRI and Kerr have explored potential markets and new technologies for the resource. The intent of Kerr was to perform the market research for this project ($60,000.00) and use the WRI technical screening alternatives to commercialize an emerging technology for the Jackson County mine operation. Kerr would decide which technology to proceed with based on the results of the scoping studies. WRI proposed the total $117,000 of the project in 1993 on a cost reimbursable basis. Only limited funds could be donated by Kerr, since the company was not in a position to provide the scheduled marketing effort and the WYCO railroad was suspending operations. Therefore the scope and depth of the study was limited.

OBJECTIVE

The objective of the coal gasification, power generation, and product market study was to develop the technical data for the potential fuel and nonfuel technology uses of a specific rocky Mountain Region resource. This information is intended to lead to other JSR projects to determine the feasibility of technical and economical alternatives for these coals.

WRI and Kerr believe that some Rocky Mountain region coals have advantages over other regional coal resources and have therefore recognized the need to plan for economic processes and increased competitiveness.

WRI approached the program with a plan for technology and product development. Aggressive testing and demonstration was aimed at establishing the real production and consumer costs. An ancillary environmental benefit was to also be derived for the project by making use of WRI's knowledge of coal byproduct reuse (e.g., fly ash as a cement replacement). The results of the project were to have had application to coal production and use throughout Wyoming and the Rocky Mountain region.

This overall program study was begun by grouping reasonable choices of technologies with an approach that would translate to cost to assess technical alternatives:

Mining, Stockpiling, and Shipping

Conventional
Hydrological
In-Situ Conversion
Pitch Binder

Value-Added Products

Metallurgical Coke
Charcoal Briquettes
Activated Carbon

Mine-Mouth Power Generation

Underground Coal Gasification and Gas Turbine
Integrated Gasification Combined Cycle
Mild Gasification

Main technology groups considered for power generation

- Pulverized coal firing and flue gas conditioning
- Circulating fluidized bed combustion boiler
- Pressurized fluidized bed combined cycles
- Integrated Gasification Combined Cycle (IGCC) options based on coal gasification

While the federal regulations on air quality have driven the use of gas-fired power generation, the use of circulated fluidized bed combustion of coal mixed with oil shale has been tested at a western Colorado site. Tri-State G&T invested in the acquisition of Colorado-Ute power plant assets as related to fuel sources and these results. This rural electric association has established a seven-year record of stable or reduced average rates to its 34 member consumers. The average wholesale rate to members is 4.0 cents per kilowatt-hour.

The direction of the project was dependent on cost sharing with Kerr Coal, existing markets, and WYCO transportation for any products generated in Walden, Colorado. This cost-shared work is needed to decide if technology development is feasible in this region for this stage of economic development and on this relatively small scale as discussed below. Since 1993, WRI has conducted surveys to gather background information on potential markets for power and value-added products generated from Rocky Mountain region coals. WRI has also periodically researched existing markets to recommend value-added or energy products with Kerr and other coal producers.

ACCOMPLISHMENTS

Project Description

The three-year project was begun with a preliminary study to develop jointly sponsored research (JSR) to further establish feasibility of the proposed alternatives to current coal production and sales at the Kerr Coal mine. This six-month project was also designed to mesh with the need for programs to develop reasonable technical alternatives for fuel and nonfuel uses of this Rocky Mountain region coal.

WRI and Kerr evaluated procedures for the proposed project(s) to identify potential markets for power and/or value-added products based on inputs from other studies in the literature (e.g., report on production of coproducts, Hogsett and Jha 1991). The work was examined in terms of:

(1) Preliminary evaluation of pilot-scale process. Based on laboratory evaluations of a given process, a pilot field prototype would be designed to develop costs of a test project.

(2) Cost and economic viability. As sufficient data became available, the cost and economic viability associated with an efficient conversion process was evaluated.

- For each product, process needs related to the resource were evaluated and volume of coal required and transportation costs were determined.
- Process development for potential products for the resource were evaluated
- JSR project cost estimates from technology assessment in the study were developed

Developments

The 1995 and 1996 legislative sessions of Colorado did not appropriate funds for economic development in North Park, Colorado. Therefore, rail transportation for products or raw coal that could have developed in this research and development by DOE and WRI, are discontinued. The Colorado-Wyoming railroad track will be salvaged for the value of the steel.

Studies by the Electric Power Research Institute (EPRI), show promise for the expanded use of Rocky Mountain region low-sulfur coal. Similar market studies by Sinor (1988), Willson et al. (1988), and Hogsett and Jha (1991) suggested that smaller power generation process development (20,000kw) could be used to initiate JSR projects. The composition of the coal from the Kerr operation is similar to that of other coals in southwestern Wyoming, so the background information collected during this project should be applicable to energy production or coal products from these coals as well.

Table 1. Average Coal Quality from Area Mines

Coal Field	North Park	Green River	Hanna	Powder River
Company	Kerr Coal	PacifiCorp	Cyprus Shoshone	Carter
Mine	Kerr	Jim Bridger	Shoshone No. 1	Caballo
Moisture, %	13.00	19.86	12.35	29.90
Ash, %	6.00	9.89	4.50	5.31
Fixed Carbon,	47.00	42.93	45.25	33.43
Volatiles, %	35.00	28.05	37.90	31.36
Sulfur, %	0.25	0.61	0.56	0.37
HHV, Btu/lb	10,600	9,400	11,449	8,450

Note: Data supplied by coal companies (as-received basis)

Some Engineering Considerations for a Power Generation Project

Increased efficiency at power plants of the future and the technology for improving efficiencies is available for reducing emissions. For example, conventional coal-fired power plants operate at 33-36% efficiency, whereas integrated combined-cycle processes operate at 45-50% efficiency. Indeed, power plant efficiencies for burning coal with combined cycles are comparable to those for burning natural gas. Improvements in coal-fired turbine technology, such as hot-gas cleanup systems and advanced construction materials, will contribute to the economic viability of coal-fired combined-cycle systems. This can occur by reducing fixed and variable power plant operating and maintenance costs.

WRI collected information relative to the possible installation of mine-site power generation or cogeneration alternatives at the Kerr mine and studied the feasibility of new process development. Kerr Coal Company, which is located in the generally pristine North Park area south of the Wyoming border, with its affiliate, Energy Fuels Corporation of Denver, has produced a report on the estimated air quality impact for a coal-fired power plant east of Walden, Colorado, and upwind of the Rawah Wilderness Area. Power generation technology would require careful selection. Estimates of emissions for a coal-fired boiler in this location are limited to 128 lb/hr. Also, the CAAA of 1990 will require that newer technology be utilized should a gas generation process be built and operated in North Park. Therefore, based on the federal regulations, the first impression is that this area would need a clean coal gasification process facility for power generation.

Because of the CAAA and emissions requirements, the demand for regional low-sulfur coal is likely to hold and power generation will therefore remain the primary use. Advanced power generation should begin to phase in over the next ten years. Global climate issues could influence the interest of the coal industry in considering processes that would improve efficiency and produce value-added products.

Electrical Power Requirements in North Park, Colorado

For the power generation project scenarios, WRI assumed a projected electrical load of approximately 20,000 kW and a possible growth over ten years to about 50,000 kW. Overall anticipated electrical demand at Walden is unknown; however, various activities had been proposed, including a visitors center and theme park, electrified rail systems to Steamboat Springs, Laramie, or Winter Park, and possible Colorado state government facilities. The most direct and straight-forward method for meeting this electrical requirement is the use of a simple open-cycle gas turbine set. This served as a starting point for process selection, with other options and variations to be selected as they became feasible.

WRI also assumed for the basic analysis in this power generation project scenario that the plant would have an annual capacity factor of 80% (which is high and suggests near base-loading). In this case, the facility would generate 134.27 MM kW•hr/yr of power, and we assumed that natural gas was available at $2.50/Mscf. Capital cost would depend on debt-equity ratios and the nature of the financing. If financed privately, interest rates near 15% were appropriate for estimating purposes. If financed through a municipal authority with tax-free bonds, rates near 8% were probably more appropriate. For scoping purposes at this stage of developing an estimate, we assumed capital charges annually of ten percent.

The Basic Gas Turbine System

A simple gas turbine system is shown in Figure 1. For this discussion, we assumed a General Electric model LM 2500 gas turbine operating with approximately an inlet temperature of 2000°F and a pressure ratio of around 12. In a basic gas turbine system, air enters the compressor, exits at nearly 200 psig, and flows to a combustor where fuel is added. At full load, 208.7 MM Btu/hr is required,

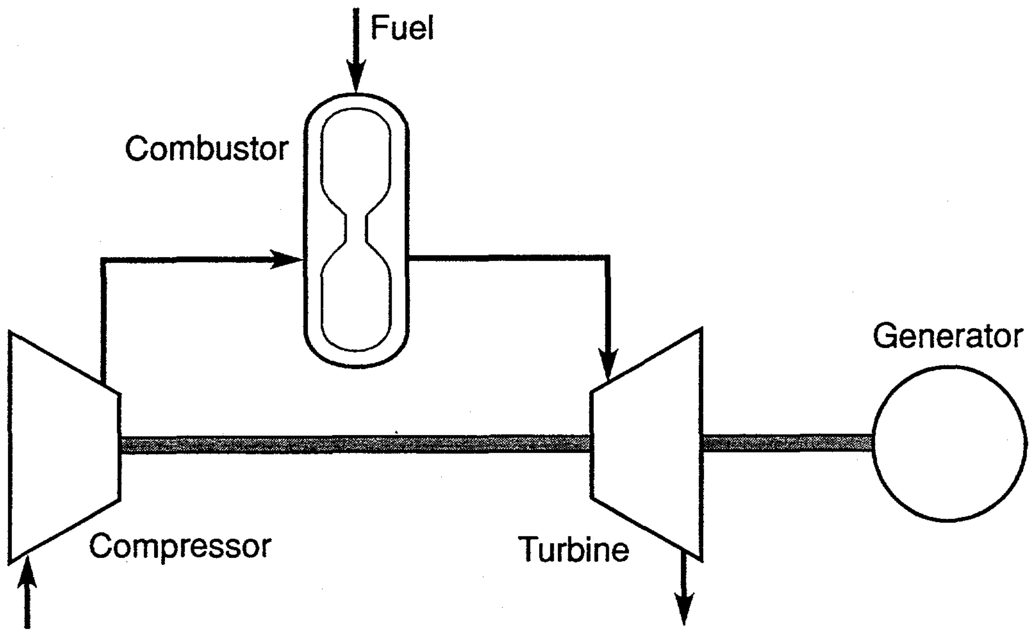

Figure 1: A Basic Gas Turbine System

either as a distillate or natural gas. The hot combusted fuel and excess air enter a gas turbine where they are expanded to atmospheric pressure and their temperature is reduced to about 980°F. The expansion of the hot gases develops approximately 19,160 kW of electricity at the generator. Overall, the turbine operates at about a 30% efficiency in converting thermal energy to power and has a heat rate of approximately 10,900 Btu/kW-hr.

Our present economic information on such a system needed to be updated, so these economics should be viewed as soft and valid for scoping purposes only. In 1986, the installed cost for this type of turbine set was about $20 million, so for purposes of this preliminary discussion we assumed $25 million for power generation equipment. Annual maintenance is approximately $250,000, and four shifts of three operators plus a supervisor are required. This yields annual operation and maintenance costs of roughly $600,000.

With these parameters, order-of-magnitude power generating costs are:

Item	Cost, $/MWhr
Fuel Cost, Natural Gas	2.72
Operation & Maintenance	0.45
Capital Charges @ 10%	1.86
Preliminary Total	**5.03**

At this stage of analysis, such figures are not unreasonable, and would suggest that further analysis is warranted. A disadvantage of the basic gas turbine system is that while inexpensive, it is thermally wasteful. In the present configuration, more than 500,000 lb/hr of gases with temperatures near 1000°F would be vented. If additional energy loads can be identified, this thermal energy can be recovered as either steam or power.

Waste Heat Recovery

A simple, straightforward method for increasing the efficiency and the output of a gas turbine is through the addition of a heat recovery steam generator (HRSG). The gases leaving the turbine are essentially hot air, thus either unfired, supplementary-fired, or fully-fired HRSGs can be added. Definitions of the terms are as follows:

- Unfired is self-explanatory - the hot gases flow from the turbine to the steam generator where their sensible heat is recovered before venting.
- Supplementary-fired HRSGs refer to units in which additional fuel is added, and additional firing is achieved, provided that temperatures in the unit do not exceed 1700°F anywhere in the unit (for purposes of metallurgy).
- Fully-fired units utilize all of the oxygen in the turbine exhaust for combustion (subject to 10% excess air) and thus employ the gas turbine efficiently as a combustion air preheater.

A properly sized HRSG allows incremental expansion of the facility to occur as external load or demand increases. For example, if steam conditions are set at 630 psig and 755°F, an unfired unit is capable of producing 64,500 lbs of steam/hr. With supplemental firing, steam output can be increased to 123,600 lbs/hr and fully-fired steam output is 390,500 lbs/hr. This steam can be used either directly for additional power generation or in combination with extraction steam turbines if consumptive steam is required by other users.

The economics of such a system are dependent on the user load demands and profiles and would have to be developed in a more detailed study. Steam generation requires both consumptive and cooling water, and this may not be desirable for Walden. If this is the case, a recuperative gas turbine cycle may be more appropriate.

Recuperative Gas Turbine Systems

In a recuperative gas turbine system (See Figure 2), the hot exhaust is not vented from the turbine but is used instead to heat the gas leaving the compressor en route to the combustor. The recuperator transfers the sensible heat in the turbine exhaust to preheat the combustion air, thereby

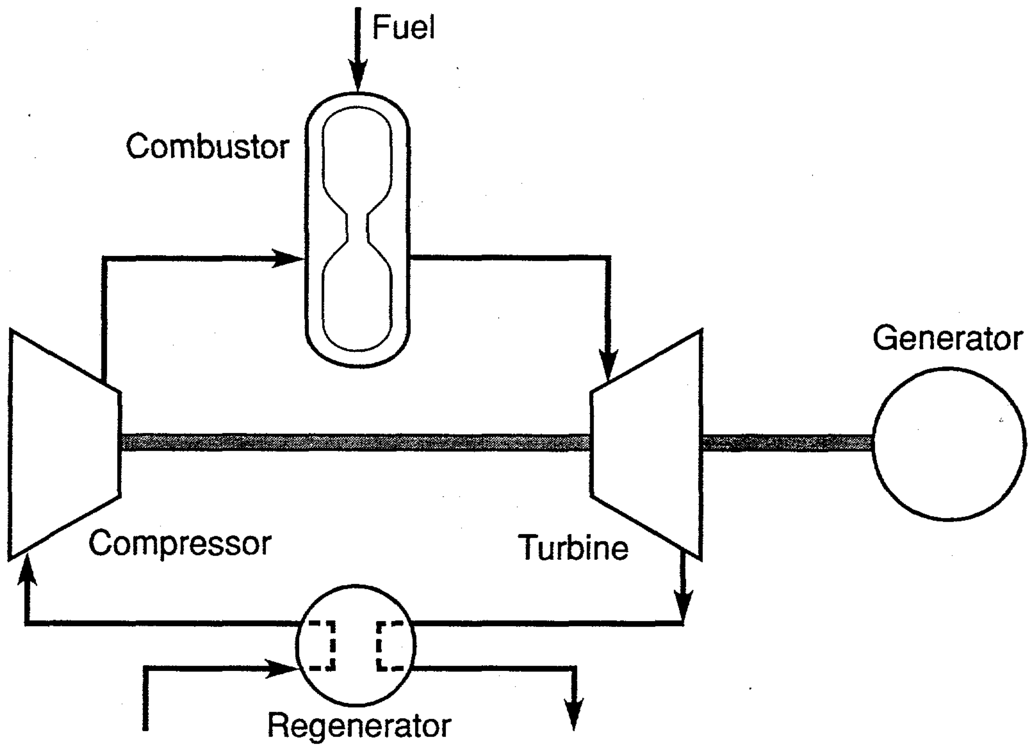

Figure 2: Recuperative Gas Turbine System

lowering the fuel required for a constant level of power generation. As compression raises gas temperatures, high compression ratios lower the amount of sensible heat that can be recovered. Thus, recuperative gas turbine systems generally operate at lower pressure ratios than do open cycle systems. These considerations become important when fuel sources other than distillates or natural gas are considered. An economic evaluation requires a trade-off between the capital charges associated with the heat exchanger and the cost of the fuel savings achieved through its use.

Alternate Fuel Systems Technology

Gas turbines without regeneration are commercially available for distillate and natural gas fuels. Thus, hardware availability and reliability for a power generation project at Walden can be considered virtually risk-free. Because of the likelihood that rail transportation would not be available, the intent of the Kerr Coal Company would be to fuel the system with coal gas derived either from surface or underground coal gasification at the mine mouth. The easiest way to evaluate this alternative is to determine whether coal gasification can provide a clean fuel gas at 200 psig to the turbine combustor for less than $2.50/MM Btu.

At full load, the turbine combustor requires approximately 200 MM Btu/hr of fuel. For this estimate we assumed that the heating value of the coal is 20 million Btu/ton and its price is $20/ton. At a gasifier hot gas efficiency of 80%, 12.50 tons coal/hr would be required. Since the turbine requires very clean gas, a hot gas cleanup system will probably be necessary, raising costs and lowering efficiencies. To be conservative, we assumed the overall system hot gas efficiency to be about 67%, thus requiring the use of 15 tons coal/hr.

In this engineering consideration, the gasifier must be provided with steam and an oxidant, in this case air. Both of these are readily available from the power generating equipment. Connecting the compressor to the turbine shaft can also provide, with a boost, the gasifier air, and the HRSG (unfired) can provide the gasifier steam. Therefore, separate units are not necessary, and the gasification capital equipment consists only of that necessary to conduct gasification and cleanup operations, as well as equipment to feed and remove solids from the gasifier. This equipment would probably have to be custom designed, but for budgetary purposes, we assumed that an additional $10 million would be adequate to accomplish this. Again as a budget estimate, we allowed $750,000 for operating and maintenance expense and assumed 10% capital charges.

With these parameters, order-of-magnitude fuel gas costs are:

Item	Cost, $/MM Btu
Fuel Cost, Coal @ $20/ton	1.50
Operation & Maintenance	0.47
Capital Charges @ 10%	0.63
Preliminary Total	**2.60**

As before, at this stage of analysis, such figures suggested that further analysis was warranted. This study then gave consideration to both surface and underground coal gasification (UCG) processes. The Kerr coal mine area would need a clean process for power generation. Also, the CAAA of 1990 has required best available control technology be utilized, should a power generation process be built and operated in North Park.

The questions addressed at that point of development were:

(1) Can UCG technology be matched to gas turbine technology in this application?

(2) Will this combination be economically competitive with conventional mining and electric power generating techniques?

This activity could begin with in-depth analyses of the literature and consultation with DOE program management. In the last two decades, a number of UCG field demonstration tests were conducted in the United States, of which most were funded in part by the U.S. DOE Office of Fossil Energy and all were conducted by organizations that are now WRI. The steeply dipping bed at Rawlins, Wyoming, is similar in geologic setting to the coal resources at Kerr Coal's Mine near Walden, Colorado. The Rawlins I field test used air as the oxidant, as would be likely for on-site power generation at the Kerr Mine. Later experiments, which received higher levels of funding as a result of the successes of Rawlins I, investigated steam/oxygen injection and gasification.

The Rawlins I demonstration successfully operated a test burn that was completed in early December 1979. Thirty tons per day of a 23-ft thick subbituminous B coal seam dipping 63° was gasified for 30 days using injected air as the oxidant. The test demonstrated that the UCG process is capable of producing a low Btu product gas with a heating value of 120-180 BTU/scf with a process efficiency of 75%. The coal was ignited at a depth of 400 ft, with gasification proceeding up the steeply dipping bed for about a 100 vertical ft during the 70-day experiment. The production gas well head pressure ranged from 90 to 160 psig. Later field tests conducted by WRI showed that the UCG process pressure controlled underground contamination of water in the process vicinity. Water contamination in the vicinity of UCG is reduced by maintaining process pressures at slightly less than the hydrostatic pressure head or roughly 1/2 psi per ft of UCG reactor depth. These results suggest that the Rawlins UCG demonstrations could have been operated at up to 200 lbs of pressure without significantly affecting ground water quality.

A typical gas turbine requires inlet pressures of approximately 200 psi. UCG-produced gas would have to have pressures in this range, and the implication is that gas reactors for this production would therefore be operated at 400-ft depth. Very deep gasification may require multistaging of turbines, perhaps with intermediate combustors. The temperature of the gas leaving the production well head is typically less than 1000°F, which is an advantage of UCG in gas cleanup control technology over surface gasifier processes.

Based on current geological data, the Kerr Coal Company mine appears to an excellent candidate for UCG technology from a technical feasibility view. The economic viability remains to be determined. Most economic studies in the literature address steam/oxygen gasification. A study of the simpler, less capital-intensive air injection system at the production level for a 20 MW scale should be done over a range of capacity factors.

Environmental permitting of a UCG site can be a long, expensive process. The permitting may be too expensive for a small plant, since economy of scale is not reached until many units/modules have been brought online. These costs, along with the political considerations of this economically disadvantaged locality, need to be addressed before a major commitment is undertaken.

Surface gasification for gas turbine power generation and co-generation opportunities are well worth investigation as part of a preliminary feasibility study. A preliminary feasibility study would include laboratory testing of the coal, as combustion testing and characterization of the Kerr coal would be required before conceptual designs for a commercial plant could be developed. Moisture and ash characteristics, agglomeration characteristics, and heating value when the coal is converted for use as a gas or in some non-fuel product.

An analysis in 1979 by Stanford Research Institute (A.J. Moll, 1979) suggests that the economic feasibility of UCG and turbine generators at the Kerr Coal mine is within reach. Economic alternatives for Kerr coal could be analysed through a JSR project comparing up to five utilization scenarios. Additional investigation has produced sufficient data to permit clarification of these feasibility considerations, an engineering study of approximately $1,000,000 will be developed.

CONCLUSIONS

This preliminary feasibility analysis suggests there are no insurmountable technical obstacles to surface or underground coal gasification development with gas turbine power generation at the Kerr Coal mine near Walden, Colorado. Certainly, the loss of the railroad should provide an impetus to efficiently use this coal resource. The preliminary economics of this type of projects are within reach, given an incentive provided by the State of Colorado. Of major concern at this stage of the analysis is determining the users of the facility's power (and steam) and developing better estimates of the project's capital and operating costs. More detailed process designs requiring engineering studies are needed.

In this project, WRI has focused on power generation with improved fuels from technology to produce efficient processes and to utilize the byproducts of coal combustion. Technology development at WRI has dealt with the physical simulation of processes and the monitoring projects with western coals, advanced fuels preparation, refining, coal processing and drying, coal combustion emissions monitoring, and environmental control activities.

The range of coal resource characteristics and technology in the Rocky Mountain region that could be improved has been explored with some producers and utilities. This limited study shows that the current economy will not support an investment for new technology for power generation or value-added products from coals for this region. For example, the capitol and current market forces will not support an integrated gasification combined cycle (IGCC) project on a localized or regional basis.

Railway transport for the Kerr Coal Co. mined coal has been discontinued. Federal, state and local leaders are receptive to ideas for the utilization of this coal resource. At first glance, more electricity for the power grid would not appear to be needed in this economically depressed region, which means the power would have to be consumed locally. Kerr Coal Company contracted with Leonhart Corporation of Denver, Colorado, to further investigate air quality requirements for more options for utilizing the resource, as Colorado state support was in the balance.

Kerr Coal Co. has an economic motive to commercialize some type of emerging technology for the now-defunct mining operation in this pristine area of Jackson County, Colorado. WRI and Kerr have evaluated data to assess gasification process requirements and coal-powered electricity generation projects. Kerr will make investment and technology decisions based, in part, on the results of these studies. For reasons of environmental compliance, and no new power generation project appears to be viable. These observations and this limited air quality study by Kerr Coal has illustrated how current environmental regulations have inhibited energy growth.

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